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Evaluation of the Primary Cement Operation on the Production Casing in the Ekofisk Field and the Eldfisk Field

Preface

The work of this thesis was performed at ConocoPhillips' offices in Tananger. I want to thank ConocoPhillips and the Well Engineering and Support Group for giving me the opportunity to write this thesis.

I would like to thank my supervisor at ConocoPhillips, Karen Bashford for excellent guidance during my work and for shearing your knowledge with me.

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Finally, I would like to thank all my fellow students during the five years at the University of Stavanger for great motivation and all the social events.

Abstract

The foremost goal of primary cementing is to provide zonal isolation in a well. Cementing of the casing/liner set right above the reservoir on the Ekofisk and Eldfisk fields are associated with a lot of challenges. Depletion and water flooding of a reservoir makes drilling and cementing increasingly difficult. At the Ekofisk and Eldfisk fields, the operational window above the reservoir is very narrow and difficult to predict due to the regression of fracture pressure the last 200 ft above the reservoir. This coupled with the natural faults and fractures in this area makes lost circulation a hindrance to provide zonal isolation. Cement history on the two fields shows that there is a very low chance of achieving required casing cement isolation.

Historical practices within the last two years have been analysed trying to find the root causes of any failure to meet the company requirements. A review of potential solutions to solve the issue has been presented. Different studies have been made, including hydraulic simulations, to come up with suggestions on how to reach the cement target for the two fields. In addition, simulations on how to cement the entire Miocene section were performed.

A study performed in WellPlan™-Opticem revealed that there still exist some challenges before the cement design and real time jobs can be properly imported and analysed in the software. During the work lack of cement job data storage system was discovered. A new way of cement data storage was suggested and established.

Collection and analyses of cement jobs during the last two years on the M-wells was performed in order to investigate if there was a trend between lost circulation and different parameters. No clear trend was found.

Hydraulic simulations were performed to investigate how different parameters impact the equivalent circulating density. A colloidal light weight cement was utilized in the simulations. The main results from the simulations showed that; Warp OBM is superior to Versatec OBM system from a well cementing perspective, the expandable liner hanger imposed a very high ECD and the liner hanger dimensions needs to be taken into account in hydraulic simulations. The overall outcome of the simulations indicates a possible solution on how to cement back to the previous casing shoe.

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1 Introduction

Primary cementing is the process where cement slurry is pumped down into the well and placed in the annulus between a casing and the formation and left there to cure. The main objective of primary cementing is to provide zonal isolation in a well. To achieve this objective a hydraulic seal must be created between the casing and cement and between the cement and the formation, while at the same time prevent fluid channels in the cement sheath. Without complete isolation in the wellbore, the well may never reach its full producing potential. This makes primary cementing one of the most important operations on a well. The primary cementing procedure should therefore be carefully planned and executed.

On the Ekofisk and Eldfisk fields the cementation of the production casing or production liner is challenging. The production casing/liner is set right above the reservoir and the cement acts as a secondary barrier element for the lifetime of the well. ConocoPhillips Norway (COPNO) has a current requirement to have the top of the cement (TOC) a minimum of 330 ft above the production packer in a completed well. Over the last two years less than 50 % of the wells have met the cement target.

The overburden on the Ekofisk and Eldfisk fields contains gas in some of the layers. If this gas is not sealed off it can cause high pressure in the annulus between the production casing and the previous casing shoe (B annulus). Proper primary cementing of the production casing has been a critical factor in well delivery and lifetime operability for several years at Ekofisk and Eldfisk. The problem is so severe that wells delivered 2-4 years ago have B annulus pressures resulting in closing in well and loss of production. Therefore, it is critical to improve the cementation procedure.

Producing formations in the same field or general vicinity can cause depleted and subnormal formation pressures because of the extraction of formation fluids. Due to the level of production from certain areas in Ekofisk and water injection the reservoir is definitely depleted, which may lead to increased drilling risks right above and in the reservoir.

The fracture gradient profile on the Ekofisk and the Eldfisk fields experiences a regression immediately above the top of the reservoir. This reduction of the fracture pressure may be increased as a result of the depletion of the reservoir leading to a different stress state in the formation. The theory states that the fracture pressure which is the minimum horizontal stress, decreases with depletion. There has been published a lot of work on this subject confirming that the decrease is predominantly linear with the depletion.

In the Greater Ekofisk Area the fracture pressure decrease seems to propagate in the Våle formation. The regression can be seen as a transition between the overburden, with relatively undisturbed conditions, and the depleted reservoir. The risk of inducing losses during cementation should therefore, in theory, be larger in the zones were the depletion, in the top of the reservoir (Ekofisk formation), is large.

The history of primary cementing shows that the overall reason for not reaching the TOC target is lost circulation. The potential for lost circulation at the top of the reservoir is high due to extensive natural faults and the regression in fracture pressure gradient right above the reservoir. This thesis focus on this work is to investigate the possibility of improving the cementation by reducing the ECD. First, an introduction to the Ekofisk and the Eldfisk fields with special emphasis on the difficulties of achieving a good cement job on the casing set in the Våle formation is given. Then a chapter with some basic theory about lost circulation included. In chapter 5, theory about basic well cementing is given.

The aim the of this thesis is to investigate different ways to reach the target of having a good cement sheath with full zonal isolation from the casing shoe to 330 ft above top the production packer (or Top of Balder formation). This has been done by reviewing published work in addition to software modelling. Different software types have been utilized to look at hydraulics and cement displacement.

The required 330 feet measured depth of cement above the production packer is to ensure that a secondary barrier exists between the reservoir and the un-cemented production casing annulus if the production casing below the production packer develops a leak. Note that since the requirement is 330 ft of effective (good) cement a larger volume should be pumped to compensate for cement contamination and displacement inefficiency .Minimum volumes should be calculated based on the well configuration and surface facilities. Small volumes have a high risk of complete contamination and volumes smaller than 40-50bbls are not recommended by either COPNO or the cement provider.

The requirement of having cement in the annulus to the top of the Balder formation (approximately 5000 ft TVD) is to ensure that a secondary barrier exists between the reservoir and the un-cemented production casing annulus in the case of fractures in the Lower Rogaland Group. It is critical to stop crude from flowing up the B annulus. The re-pressurization of the field, during water injection makes the need even more urgent. Data from earlier work shows that the fracture gradient starts declining approximately 350 - 400 ft TVD above the top of the Ekofisk formation top.

A proposal has been made by staff within the drilling group to extend the TOC for the production casing to cover the entire Miocene section i.e cementing back into the previous casing string. This is a step change in the cementing practices for COPNO. Recommendations based on options available on how to move towards this long term objective is given in the thesis.

In order to look at suggestions on how to cement the entire Miocene section (i.e. cement up in the previous shoe) a modelling of different scenarios was done in CemFacts. CemFacts is another simulation program that basically works like OptiCem. CemFacts was used due to issues with WellPlanTM-OptiCem.

2 The Ekofisk Field and the Eldfisk Field

2.1 Introduction

The Ekofisk field is located in block 2/4 in the southern part of the Norwegian sector of the North Sea. Figure 4 1 shows the position of the Ekofisk Field. The field was discovered in 1969 and production started in June 1971. The Ekofisk field is the largest of the Central Graben chalk fields (1989) The original oil-in-place and original gas-in-place volumes were estimated to 6.4 billion barrels oil and 10.3 TSCF gas, respectively (Bashford, 2008). Water injection into the Ekofisk field commenced in the end of 1987 (Berg & Liland, 1999).

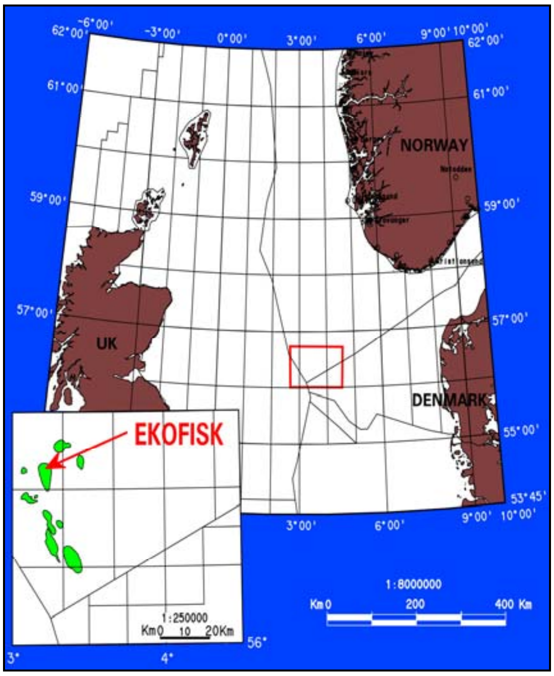


Figure 2-1 Map of the Ekofisk field location (Mikalsen, 2008)

The Eldfisk field is located in block 2/7 in the southern part of the Norwegian sector of the North Sea, and was discovered in 1970. Production at the Eldfisk Field started in 1979. Original oil-in place and original gas-in-place were estimated to about 2.96 billion barrels and 4.4 TSCF, respectively. Waterflooding of the reservoir started in 2000. Most of the vertical wells and injectors have been sidetracked to optimize the production from the reservoir (Green, Johnson, & Hobberstad, 2003)

The Eldfisk Field consists of three structures, the Bravo structure to the north, the Alpha structure to the south, and the East Eldfisk that is located east of the Alpha structure. The area of the field is approximately 29 km^2 with a producing interval of 1000 ft.

The East Eldfisk structure is a subtle domal uplift located Northeast of the Alpha structure. East Eldfisk is being reviewed for potential development as part of the upcoming Eldfisk Phase II project. Currently one ERD well is producing from East Eldfisk (Bashford, 2008).

2.2 Geological Setting

The Central Graben, where the Ekofisk and Eldfisk fields are located, was initiated in Late Triassic time by a major period of rifting. This crestal extension and subsidence continued through the Jurassic time creating a fault where thick highly organic Kimmerigde shales were deposited. The Kimmerigde shale is the principal source rock throughout the North Sea and is the source rock for the Ekofisk and Eldfisk fields. The subsidence continued gradually throughout the Cretaceous time and lead to the transition of deposition of shale in shallow waters to deepwater chalk by the end of early Cretaceous (Van Den Bark & Thomas, 1981) and (J.A.Dangerfield & D.A.Brown, 1987). By late Cretaceous Maastrichtian age chalk deposition was widespread in the North Sea. By the end of Danian age over 3000 ft of chalk was accumulated in the Ekofisk area forming the reservoir of the Ekofisk field (Van Den Bark & Thomas, 1981).

2.3 Reservoir Description

The reservoir rock at the Ekofisk and Eldfisk fields is a fine grained limestone. This chalk mainly consists of spherical calcareous exoskeletons called coccospheres. Coccospheres are debris from pelagic unicellular gold-brown algae called coccolithophores (Sulak & Danielsen, 1989),(Van Den Bark & Thomas, 1981) and (J.A.Dangerfield & D.A.Brown, 1987). The coccospheres are made of a number of very tiny platelets called coccoliths (J.A.Dangerfield & D.A.Brown, 1987) See Figure 2-2. Coccoliths are wheel shaped elements that range from 10 to 30 μm in size. Coccospheres are rarely preserved in the sediments. However, complete coccoliths are relatively common, but the majority is broken up into platelets which are their basic calcite crystal constituents (Sulak & Danielsen, 1989)

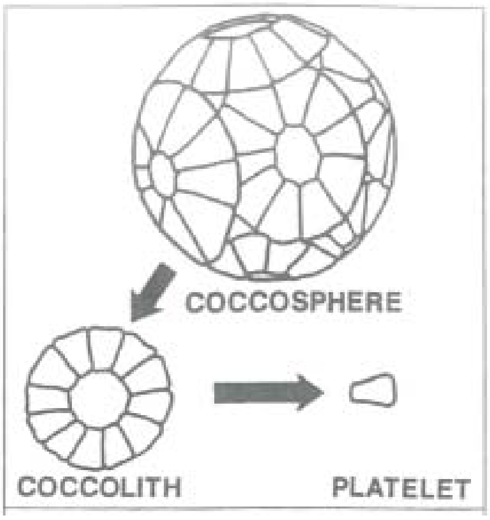


Figure 2-2 Coccospheres, coccolith and platelets (Sulak & Danielsen, 1989)

2.3.1 The Ekofisk Field

The Ekofisk reservoir is an elongated elliptical anticline, with the major axis in the north/ south direction. A cross section of the dome structure of the reservoir can be seen in Figure 2-3. The reservoir is approximately 6.5 miles in length in the N-S axis and 3 miles along the E-W axis. The top of the reservoir at lies at 9500 ft TVD at the crest and 10200 ft TVD on the the flanks (Mitchell et al., 2004; Nagel, 1998). The reservoir thickness varies between 300 ft and 1000 ft (Mitchell et al., 2004). A map of the reservoir on the Ekofisk field is shown in Figure 2-4.

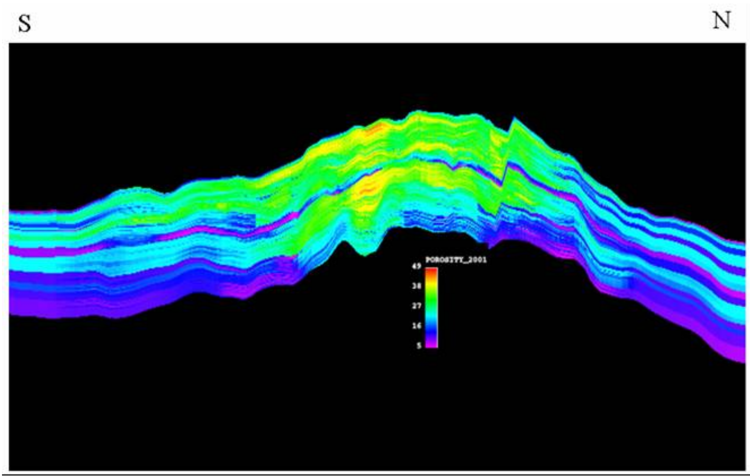


Figure 2-3 Cross section of the Ekofisk reservoir (Bashford, 2008)

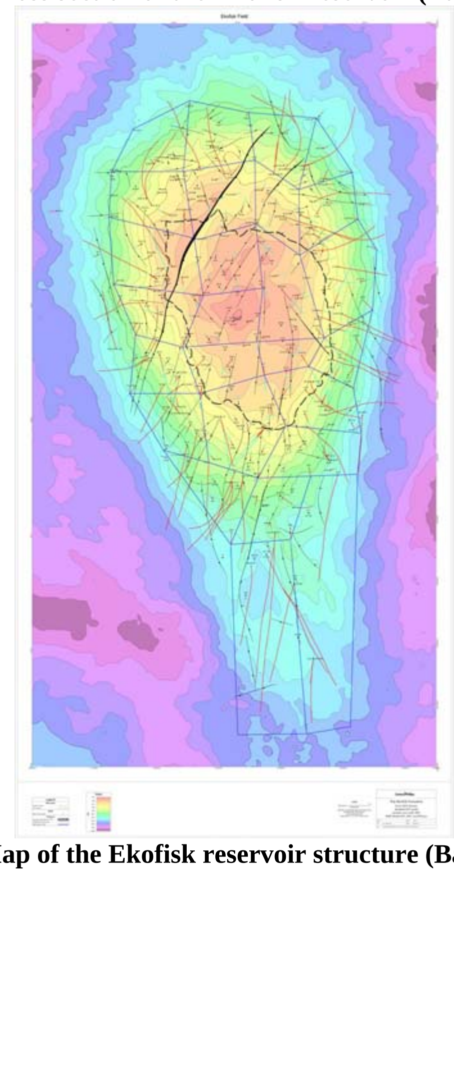


Figure 2-4 Map of the Ekofisk reservoir structure (Bashford, 2008)

Faults and fractures are important for fluid flow in the Ekofisk reservoir, by increasing the permeability significantly, making channels and forming barriers. The permeability in the chalk ranges from 1 to 5 mD but the extensive natural fracturing has resulted in an effective permeability of as much as 100-150 mD (Bashford, 2008; Nagel, 1998). Figure 2-5 shows the massive faulting in the Ekofisk field. Over 400 faults have been mapped and approximately 100 of these have been incorporated in the reservoir flow model. The largest fault is the fault in the north west of the field which continues into the overburden (Figure 2-4) (Bashford, 2008). The faults have been causing problems when drilling and cementing wells in this area. Some of the major losses are most likely connected to these faults. Faults located near the production casing setting depth can result in massive losses. If losses are taken here during drilling, a part of the mud column can be lost. This can result in a kick and loss of well control. For future wells it will be important for the geologists to predict where the faults are. It this way these hazardous areas can be avoided when planning the casing setting depth.

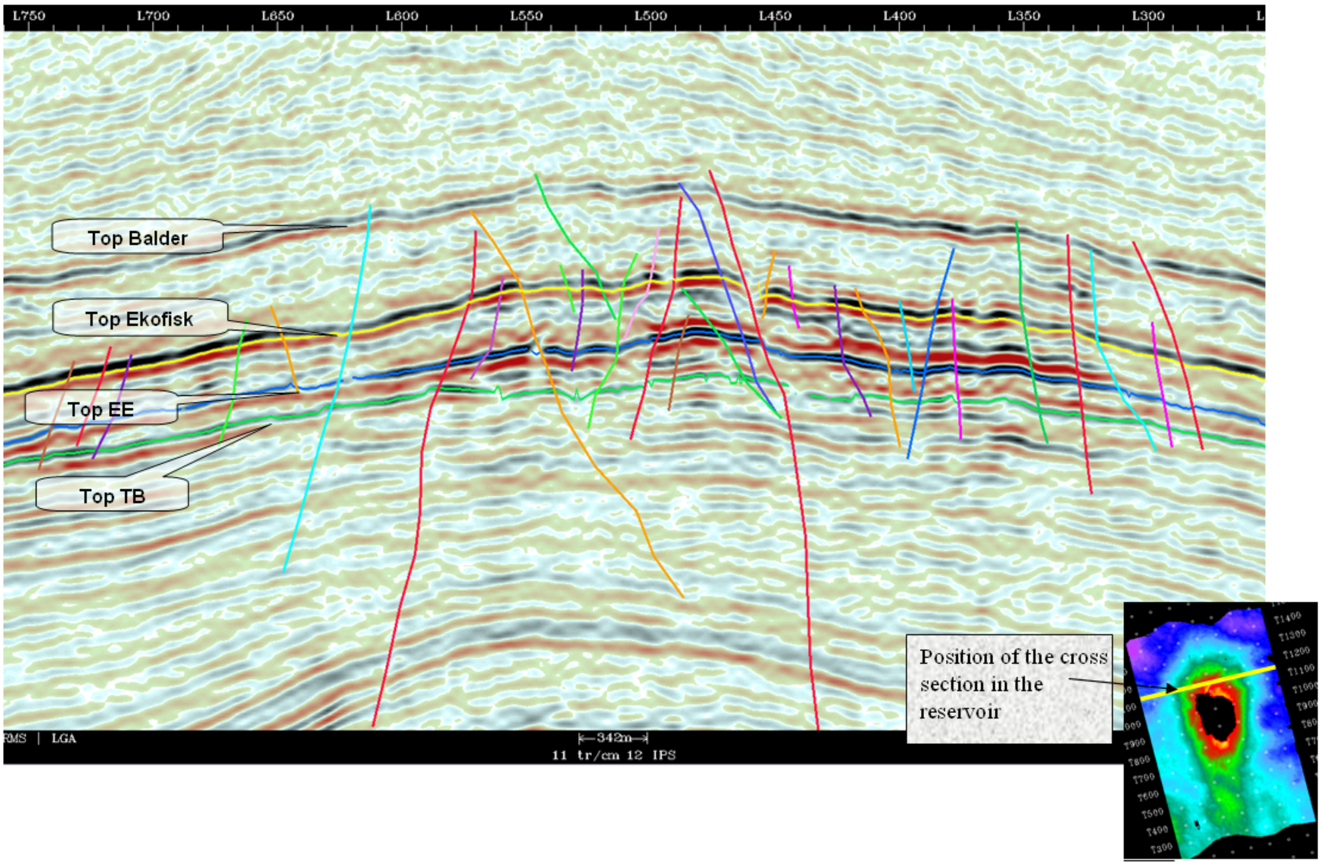


Figure 2-5 Fractures in the reservoir at the Ekofisk Field (modified (Knight, Sinet, Krantz, & Seiffert, 2008))

Characterization of the fractures is mainly based on core and image log studies to generate quantifiable estimates of fracture type and density. Still, some challenges remain when it comes to describing the fracture frequency near faults, the fracture length and aperture (Knight et al., 2008).

The Ekofisk reservoir consists of two hydrocarbon bearing formations, the Ekofisk formation and the Tor formation. These two fractured chalk horizons are separated by a 30 to 60 ft, low porosity layer, called the Ekofisk Tight Zone. Except for a minor number of fractured areas, this layer prevents fluid migration between the formations (Nagel, 1998), (Hermansen, Thomas, Sylte, & Aasboe, 1997)

The Ekofisk formation is from Danian age and the top of the formation is located at about 9600 ft TVD and ranges in thickness from 350 to 500 feet TVD (Hermansen et al., 1997). The Ekofisk formation is divided into five layers: Upper Porous Layer (EA), Tommeliten Tight Zone (EB), Reworked Danian Layer (EC), Reworked Maastrichtian Layer (ED) and Ekofisk Tight Zone (EE). The five Ekofisk formation layers layers differ in thickness, lithology and reservoir properties (Lawrence, Pekot, & Gersib, 1987; Mitchell et al., 2004). The porosity in the productive zones varies between 30 to 45% (Bashford, 2008). The porosity is high in the crest of the reservoir structure and declines to the flanks (Mitchell et al., 2004; Nagel, 1998). Approximately two thirds of the estimated 6.4 billion STB hydrocarbon pore volume in place is found in the Ekofisk formation (Hermansen et al., 1997).

The Tor formation is of Upper Maastrichan age in the Cretaceous period and is divided into three main units; TA, TB and TC. The TA layer is the best producing layer (Bashford, 2008), and approximately half of the total oil production from the Ekofisk field comes from this layer (Lawrence et al., 1987). The TB layer is a producing layer for wells with Total depth (TD) in the crestal part of the field. On the flanks this layer has a too high water saturation to be produced. The TC layer is a tight non-productive layer (Lawrence et al., 1987). Conventional deviated wells are normally drilled to the upper part of the TC layer (Bashford, 2008). The Tor formation varies in thickness from 250 to 500 ft. The porosity in this formation varies from less than 30 to 40 % (Hermansen et al., 1997).

2.3.2 The Eldfisk Field

The Eldfisk field is a chalk reservoir with high porosity and low permeability. Porosity values range from 30 % to 40 % in the reservoir. The matrix permeability varies between 0.02 mD to 10 mD. Fractures in the reservoir increase the permeability, and the permeability can in some areas approach 25 mD or higher. The initial reservoir pressure was 6800 psia. Static Bottomhole temperature is 268°F (Green et al., 2003). Depth of the main reservoir varies between 9800 ft TVD and 12000 ft TVD.

The Eldfisk field produces hydrocarbons from three naturally fractured chalk formations; the Ekofisk formation, the Tor formation and the Hod formation. The Hod formation is of reservoir quality only at the Alpha structure (The crest of Alpha structure is located at approximately 8800 ft TVD and the crest of the Bravo structure is at approxiamtely 9100 ft TVD. The free water level at the Eldfisk Field is estimated to be at 10300 ft TVD.

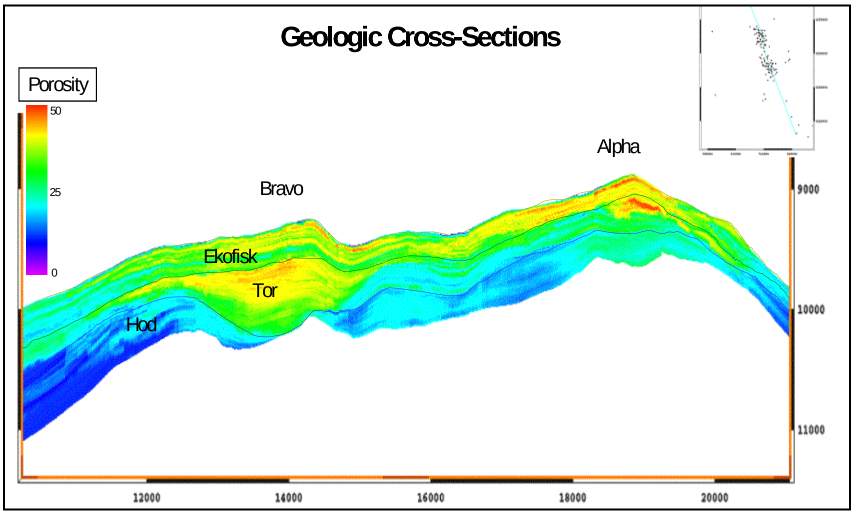


Figure 2-6 Cross section of the Eldfisk field (Bashford, 2008)

The Ekofisk formation has a fairly even thickness across the Eldfisk structure. The subdivision of the Ekofisk formation is constrained by the presence of field extensive marker horizons. The two most striking of marker horizons clearly subdivide the formation into 3 main units: the upper, middle, and lower Ekofisk formation (EU, EM, and EL). This is similar to the subdivision of the Ekofisk formation found in the Ekofisk field. However, the chalk properties found within these intervals do not necessarily match. The Lower interval on the Eldfisk field can be characterised as a fairly low porosity unit, while the same interval on the Ekofisk field represents the main reservoir interval. In the Middle Ekofisk time, thick layers of high porosity gravity flows were deposited where the Eldfisk Field is located. However, on the Ekofisk field, the middle layer in the Ekofisk formation is dominated by highly variable quality chalks. The Upper formation is evenly distributed on the Eldfisk field, only a slight increase in thickness can be seen on the Alpha structure compared to the Bravo structure. This is probably because of better preservation of the porosity due to a structural higher location of the Alpha structure compared to the Bravo structure. The character of the Upper Ekofisk formation is very similar in both the Ekofisk field and the Eldfisk field. The Upper Ekofisk formation in both fields shows a stepwise decline of the chalk properties upwards into the overburden. The Upper layer is slightly thicker in the Ekofisk field than in the Eldfisk field, this may be because of the more basinal location of the Ekofisk field.

The Tor formation is characterized by high porosity chalks. The thickness of the formation varies dramatically from 20 ft to more than 600 ft. This, together with the homogeneous nature of the Tor chalk makes the subdivision of this layer difficult.

The Hod formation can be subdivided into four layers. Production from the Hod formation is limited because of poor reservoir properties (Bashford, 2008).

2.4 Subsidence

Subsidence of the Ekofisk field was discovered in 1984. The subsea under the Ekofisk Complex had then subsided some 10 ft. The subsidence, when discovered, was quite unexpected. Before this time it was believed that productivity was linked to reservoir compaction by means of reducing the production, i.e. as long as productivity did not decline, compaction was not occurring.

Today, the subsidence in the reservoir on the Ekofisk field is about 36 ft. Reservoir compaction and surface subsidence are not occurring at the same rate. Compaction of the reservoir rock leads to a decrease in gross reservoir height and the top of the reservoir moves downwards. As the top of the overburden moves downwards, the overburden will follow. Eventually, the seabed moves downwards also, but this occurs at a slower rate. The net result is that the overburden is effectively increasing in overall height (Bickley & Curry, 1992). Due to this stretching of the overburden, the subsidence seen on the surface today is 30 ft. The subsidence data on the Ekofisk field is collected from bathymetry data, GPS at the surface, and from well monitoring (2/4-C-11 A and 2/4-C-11) that measures the compaction (Moe, 2009). On the Eldfisk field there is no well that is monitoring the subsidence. This makes the subsidence of the reservoir there more uncertain. Bathymetry data and GPS show that the subsidence on Eldfisk is about 10 ft (Hagen, 2009).

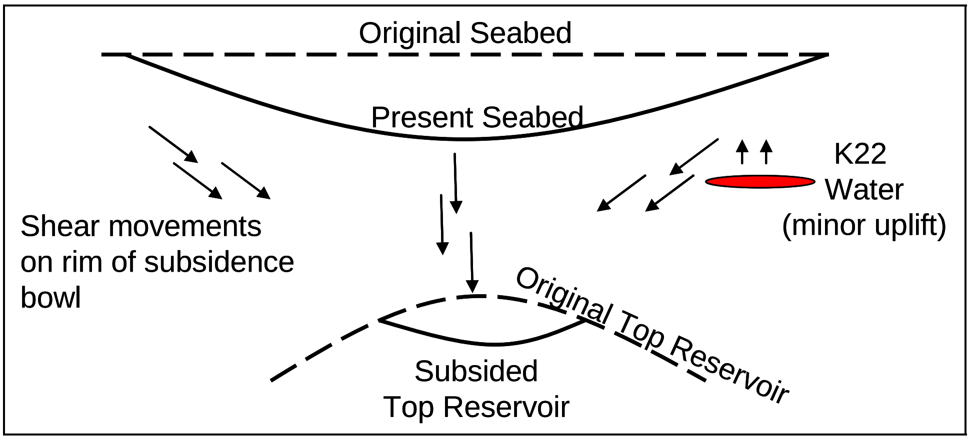


Figure 2-7 Subsidence of the Ekofisk field (Bashford, 2008)

Subsidence of the Ekofisk and Eldfisk fields is due to compaction and weakening of the reservoir rock and the stiffness in the overburden rock structure. The major effect of the seabed subsidence is the compaction of the reservoirs as the hydrocarbons are produced and the pore pressure declines. When the pressure in the pores decreases the reservoir rock matrix must be able to carry more and more of the weight of the overburden. The rock matrix is too weak to support the entire weight of the overburden and the matrix begins to fail, which causes compaction (Sulak & Danielsen, 1989)

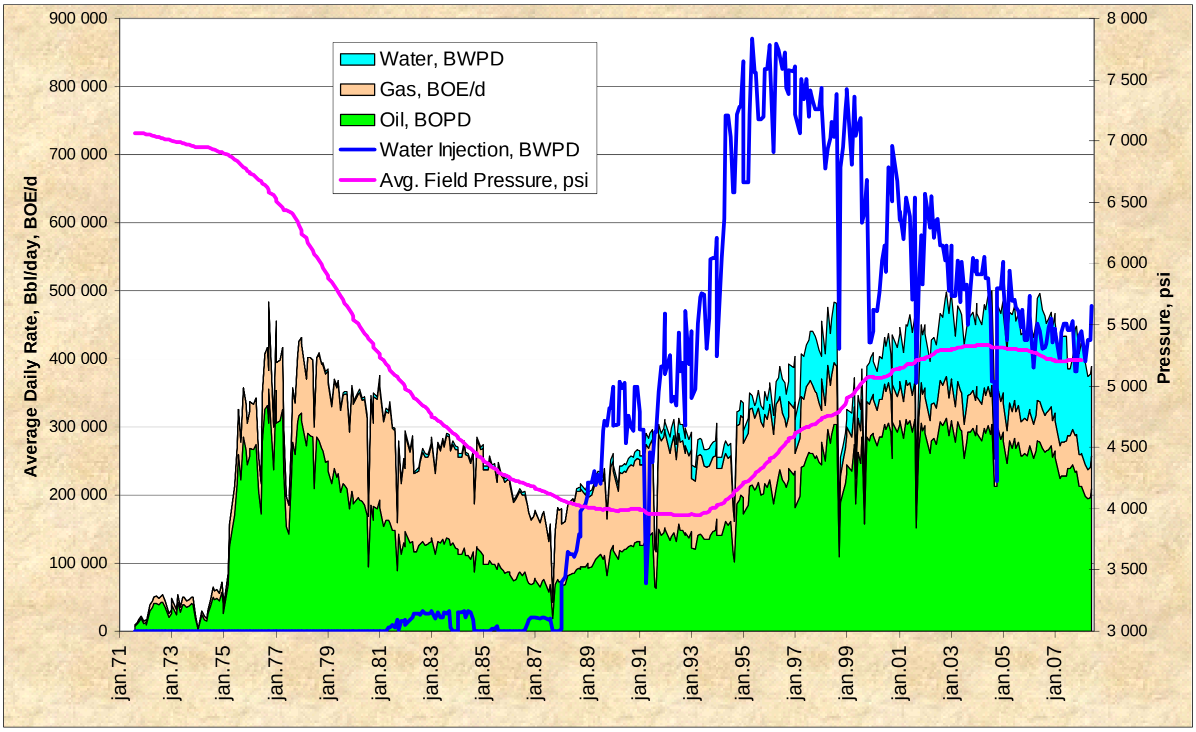


Figure 2-8 Production rate, Water injection rate and pore pressure change during the production of the Ekofisk Field (ConocoPhillips, 2009)

Water injection in the Ekofisk field started in 1987 to give pressure support and to prevent compaction. The injection of water has been a great success and the oil recovery is now around 50% (Austad, Strand, Madland, Puntervold, & Korsnes, 2008). One of the consequences with water injection is its ability to modify chalk strength and affect chemical compaction (Sulak & Danielsen, 1989). After water injection commenced, the compaction of the reservoir continued in the water flooded areas even though the reservoir was repressurized by the injection of seawater. Thus, seawater appeared to have a so called water weakening effect on the chalk. There is today no doubt that the sea water has a special interaction with chalk at high temperatures. This effect has an impact on the oil recovery and rock mechanics (Austad et al., 2008).

The strength of a rock is to a great extent dependent on the porosity and silica content. However, many studies have shown that the strength of chalk is determined by the saturation fluid. As early as in 1989 it was discovered that water has a pronounced weakening effect on chalk. From that time and until today, many different studies have been conducted to research the effect water flooding has on chalk. One thing that is certain is that water injection modifies the chalk strength and affects chemical compaction. The latest studies on chemical aspects of the interaction between seawater and chalk indicates that surface active components in seawater like Ca^{2+}, Mg^{2+} and SO_4^{2-}, plays an important role in wettability modification and rock mechanics (Austad et al., 2008; Heggheim, Madland, Risnes, & Austad, 2005)

Figure 2-8 above shows the average daily rate versus time and reservoir pressure on the Ekofisk field. It can be seen from the figure that the initial reservoir pressure drops from about 7200 psi in 1971 to approximately 4000 psi in 1993. After this, the water injection rate is increased and the reservoir pressure is repressurized up to about 5200 psi.

The arch effect is another result of the reservoir subsidence. The compaction and subsidence of the reservoir will transfer some load from the crest of the field to the flanks of the field, creating a stress arch. The stresses on the flanks are increasing due to these shear movements (Sulak & Danielsen, 1989) This can be seen in Figure 2-9 below.

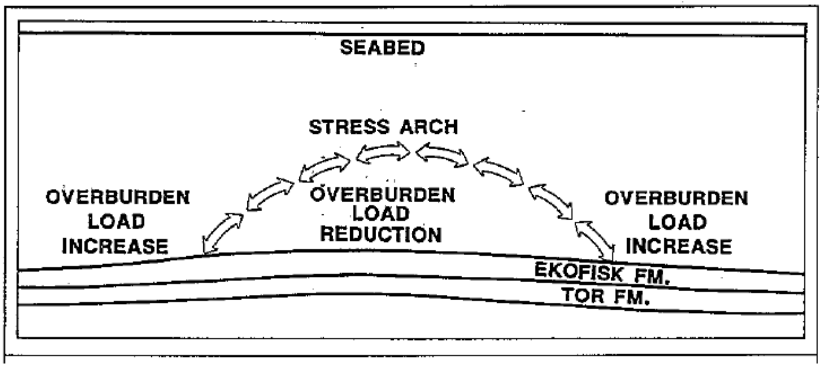


Figure 2-9 Stress arch (Sulak & Danielsen, 1989)

The minimum horizontal stress, σ_h, varies across the fields as a function of position in the structure. On the Ekofisk field the lowest magnitudes of σ_h exist on the crest and the highest on the flanks, particularly on the outer north and south flanks(Teufel & Rhett, 1991). Due to the depletion of the reservoir, the formation above has a lower fracture pressure than prior to production. This will be further explained in chapter 2.6.1

Both the Ekofisk field and the Eldfisk field are undergoing compaction and subsidence, but the subsidence is more severe on the Ekofisk field. This may be due to earlier start of the production on the Ekofisk field. The subsidence and the compaction of the fields have an effect on the lifetime of the wells and on the conditions in the overburden. The casings are mechanically deformed and bent because of the changes in the formation related to the compaction. Therefore, it was previously believed that production casings should be cemented with a small amount of cement, which was enough to prevent u-tubing when the shoetrack was drilled out, but were in lack of providing long term zonal isolation. This was done to reduce the forces acting on the casing in the overburden. Studies had indicated that by minimizing the connection between the casing and the borehole, the well would be more robust in a subsiding reservoir situation. “In the overburden, particularly in the lower layers, the overburden elongates and shifts horizontally between the layers. Cemented casing is subjected to the same elongation and tensile loading results. The tensile loading can be enormous and cause a drastic decrease in hydraulic collapse resistance. Cemented casing also experiences tremendous localized bending and shear forces due to the lateral shifts in the formations” (Bickley & Curry, 1992). Previously the 12 ¼” hole, which is drilled to just above top of the reservoir was underreamed from right above the Balder formation to total depth of the section. This was to compensate for the lateral movements of the rock caused by subsidence. In order for the underreaming to be effective, the casing should be able to move freely in the open hole. “Rigidly cementing of the casing would prevent this moving and cause casing deformation, even with relatively small horizontal movements in the formation”(Bickley & Curry, 1992). The small amount of cement placed at the production casing shoe was therefore designed to be sufficiently weak to allow the casing to “float” in the cement (Bickley & Curry, 1992).

The substantial compaction and subsidence are the primary reasons for the multiple well failures in the history of Ekofisk and Eldfisk. The second reason for the numbers of wells with mechanical integrity problems, is this old practice of cementing only the very bottom of the production liner or casing at top of the reservoir. Many wells were delivered with only 10-20 ft of cement around the shoe. It is today clear that this strategy did not deliver the required reduction in well failures, and many wells were seen to suffer with annulus pressures. A decision was therefore made in 2007 to increase the amount of cement required in the production casing annulus. In the long term perspective, the aim is to provide an still improved cementation of this interval (Bashford, 2008). This includes cementing the entire overburden section, especially the Miocene level.

2.5 Overburden

The formation between the seafloor and the top of the reservoir, the Ekofisk formation is defined as the overburden. The overburden stratigraphy on the Ekofisk field and the Eldfisk field is divided into three lithographic sequences; Nordland group, Hordaland group, and Rogaland group

Table 2-1 Stratigraphy of the overburden (Mitchell, Nagel, Onyia, & VanDeVerg, 2006)

Age		Group		Formation	OW pick name
Recent		Nordland			
Tertiary	Pliocene	Nordland			
Tertiary	Miocene	Nordland			
Tertiary	Miocene, Oligocene	Hordaland		Lark	14AL
Tertiary	Eocene	Hordaland		Horda	18AL
Tertiary	Eocene	Rogaland		Balder	20BA
Tertiary	Paleocene	Rogaland		Lista	21SA
Tertiary	Paleocene	Rogaland		Sele	22LA
Tertiary	Paleocene	Rogaland		Våle/Maureen	25VL
Tertiary	Paleocene	Rogaland		Dense Lower Våle	25.5 DLV
Tertiary	Paleocene	Danian	Chalk	Ekofisk	EA1
Tertiary	Paleocene	Danian	Chalk	Ekofisk	EA2

In Table 2-2 below is the approximately overburden layer depth TVDSS given for the Ekofisk and Eldfisk fields. As it can be seen from the table, there are only small changes in the depth between the two fields. This also goes for the lithology and composition.

Table 2-2 Overburden layer depth

Layer	Approximately Depth TVDSS [ft]	
	Ekofisk Field	Eldfisk Field
Overburden TD range	9500 -10200	8800 - 9800
Nordland group	0 - 5000	0 - 5000
Hordaland group	5000 - 9000	5000 - 8000
Rogaland group	9000 - 10200	8000 - 9800

2.5.1 Nordland Group

The Nordland group is the uppermost group of the overburden and extends from the seafloor down to the middle Miocene unconformity. The group is characterized by poor sorted silt (till) of clay, silt, sand sediments, pebbles and even boulders occurs as well in the shallowest sections below sea-bottom. A lower frequency of limestone beds are encountered in the Nordland group than in the underlying mud rich formations in the Hordaland and Rogaland groups (Mikalsen, 2008).

The 14AL seismic marker in the Nordland group consists of shale with low permeability and represents a geologic unconformity. In the 14AL surface the overpressure ramps faster than in the zone from top of overpressure at ~3300 ft TVD. A seismic cross section of the Nordland group shows a high number of faults right below the 14AL marker. This is one of the reasons why well collapses in the overburden often are found to occur in this zone. Extensive faulting can be found in the flanks of the field where the greatest slip movement has occurred due to subsidence (Mikalsen, 2008). The potential for losses during drilling and cementing of wells are therefore expected to be higher on the flanks of the fields. The 14 AL marker also represents acts as a seal for the Miocene and reservoir gas leaking up through the overburden. This is further explained below in part about the Hordaland group

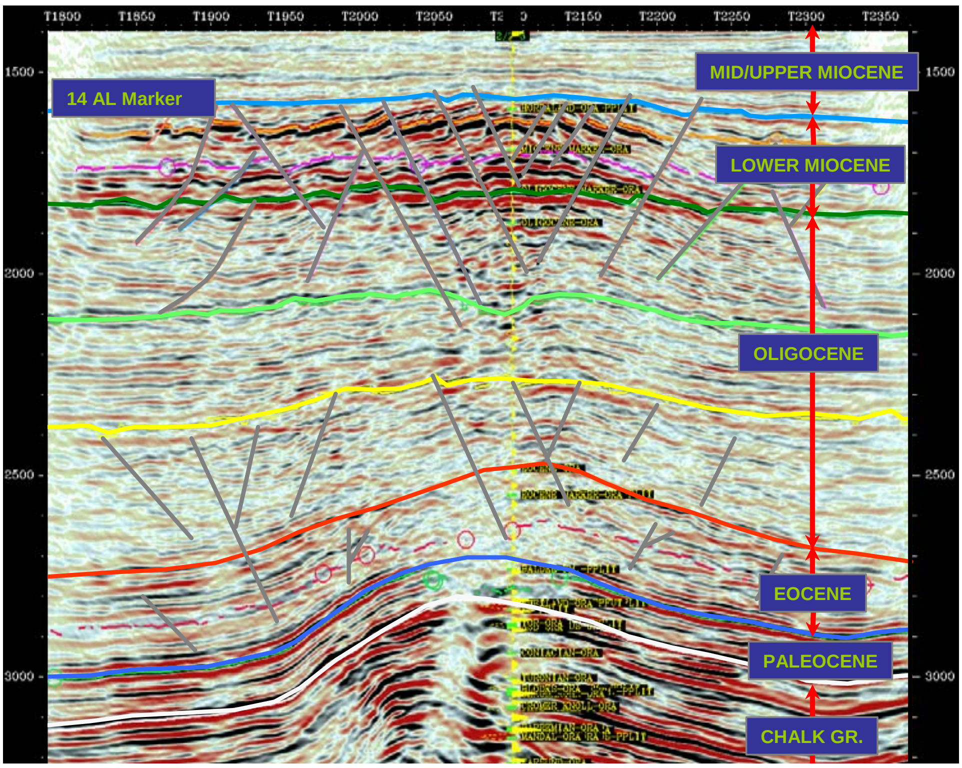


Figure 2-10 Seismic cross section of the Nordland group (Mikalsen, 2008)

2.5.2 Hordaland Group

The Hordaland group is Eocene Miocene in age and is made up of the Lark formation and the underlying Horda formation.

Features of the two formations can be found Table 2-3 below.

Table 2-3 Hordaland Group (modified (Mikalsen, 2008)

Formation Name	Thickness	Description	Drilling / Well Hazards
Lark Formation	2800 to 3400 ft	Mudstone. The interval is locally silty with frequent limestone stringers, especially near the base.	The Lark is highly overpressured and contains gas and oil from the underlying reservoirs.
Horda Formation	600 to 900 ft	Mudstone. More heterogenic than the Lark, with both silt and limestone stringers.	Lower gamma ray response than the overlying Lark Formation.

The formations in the Hordaland group is characterized by well collapses and lost circulation. The group is potentially unstable due to the high number of small-scaled normal faults showing a polygonal pattern. See Figure 2-10. (Mikalsen, 2008)

Over the last two years, COPNO has experienced problems getting the casing to TD in a number of wells drilled. The effects of this are poor cement jobs and hole stability issues in the next section, even if the mud weight is increased. In some cases, the casing is packed off before it reaches TD. It can therefore be problematic to perform a conventional primary cement job and pump cement around the shoe. To avoid disturbing the overburden and to reduce the well control problems, it is critical to have focus on getting the casing to the right setting point (Mikalsen, 2008).

In the Ekofisk field there are also limestone stringers throughout the overburden which have significantly different compressive strength than the surrounding shales. In the period from 2006 to 2008 these stringers have become much more of a drilling hazard than previously. Pack-offs are common in the stringers and local hole stability issues have been seen around certain areas of the field (Mikalsen, 2008).

<u>Gas in the Overburden</u>
The presence of gas above the reservoir is a well known phenomenon on the Ekofisk and Eldfisk fields (Nagel, 1998). It is in the area from the Lower Miocene to the Eocene where highest concentration of gas in the overburden is observed during drilling. The 14AL level acts as a semi seal for the Miocene level and the reservoir gas leaking up through the overburden. The formation located below the 14AL level therefore displays higher concentration of gas than the formation above. The Miocene level is characterized by an anticline structure draped over the reservoir and has a four way closure, which act as a hydrocarbon trap. The 14AL structure is located at 5300 ft TVDSS at the crest and around 500 ft TVD deeper on the flanks (Mikalsen, 2008).

The Ekofisk field is seismically obscured over the crest of the reservoir caused by gas and differential pressure compartments. Differential pressure compartments are most likely created in the undercompacted overburden formations. The overburden is undercompacted due to late rapid sedimentation. The gas is a combination of in-situ gas and gas which has migrated from the reservoir over geological time. The gas content is generally low and unable to produce, but it is occasionally creating drilling challenges at the Miocene formation (Mikalsen, 2008).

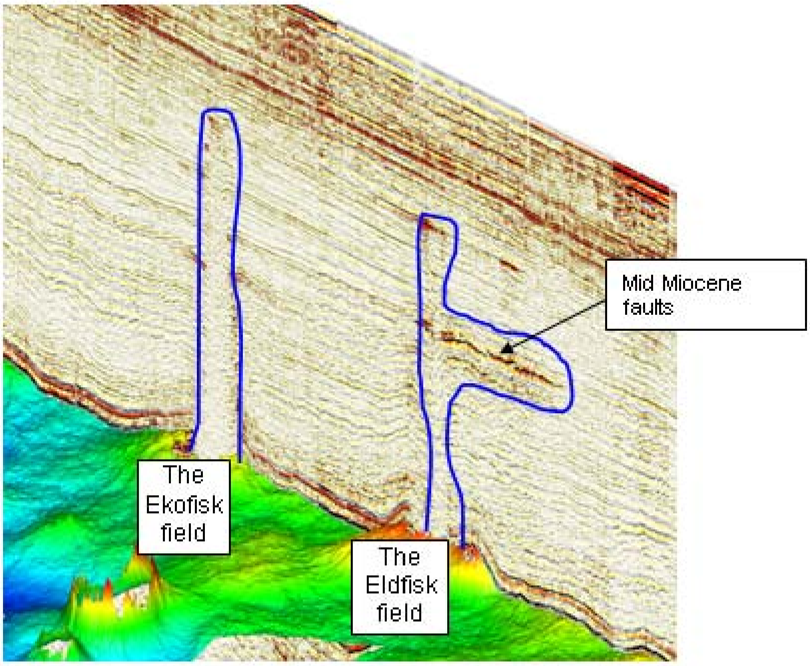


Figure 2-11 SOA on the Ekofisk and Eldfisk Fields (modified) (Mitchell et al., 2006)

The extent of the seismic-obstructed area, SOA, is shown in Figure 2-11 relative to the position of the reservoir. Note that in the Eldfisk field the faulting in the mid Miocene has allowed gas and overpressure to migrate laterally, thus enhancing the size of the SOA [3, 26]

An important future challenge will be to obtain seismic resolution in this area. Attempts have been made with vertical seismic profile (VSP), microseismic, and ocean bottom cable (OBC) (Mikalsen, 2008). COPNO is now installing, *Life of field seismic (LOFS)*, across the Ekofisk field to monitor 4D seismic (Bashford, 2009)

Today, the amount of gas observed in the overburden is seen higher in the formation than before. Earlier, there was limited gas volumes observed above the 14AL marker, but recently there have been observed higher amount of gas above this marker in some areas of the Ekofisk field. The gas concentration during drilling seems to be more unpredictable today than earlier due to stress changes in the overburden fractured formations. (Mikalsen, 2008) One reason for these observations might be gas and crude migration through micro annuli in the cement sheath around the production casing.

The X platform in the Ekofisk field has always reported overall higher gas readings than the other platforms most likely because of its position right above the SOA area (Bashford, 2009) Recently the gas readings from the X-platform are even higher. Two recent wells on the X-platform had crude kicks. These kicks may be caused by gas leaking up the in the B-annulus. As the reservoir is waterflooded, the reservoir pressure increases. This will makes any leakage even worse. To improve the cementing practices it is very critical to avoid kicks during sidetracking in the future.

2.5.3 Rogaland Group

The Rogaland group is consisting of the Balder, Sele, Lista and Våle formations. The group ranges in thickness from 300 ft to nearly 600 ft. The formation consists of shale which contains siltstone and sandstone streaks (Mikalsen, 2008). Since 2004, the setting depth of the production casing in the Eldfisk and Ekofisk fields has been 67% into the Våle formation. This setting depth is in the "Dense Lower Våle formation". The setting depth is picked based on log readings (comparing and looking at other wells nearby), ROP , lithology etc. with the final exact depth being determined by a combination of Micropalaeontology and Palaeontology (bugs + pollen) description. The reason for picking this setting depth is to hold back the unstable overpressurized Lista formation and to allow drilling the reservoir chalk with a lower mud weight (Bashford, 2008; Mitchell et al., 2004). This will be further described in section 2.6.4. Table 2-3 below gives a brief overview of the Rogaland formations.

Table 2-4 Rogaland Group (Mikalsen, 2008; Mitchell et al., 2006)

Formation Name	Thickness	Description	Drilling / Well Hazards
Balder Formation	20 to nearly 50 ft thick	Mainly tuffaceous shale (ash bed). Friable sand was also encountered in the interval in well 2/7-2.	Compared to the marine shale above and below, the Balder Formation ash bed is more competent, indicated by less washout, and has a higher density, lower porosity, and faster sonic transit time.
Sele Formation	100 ft to over 200 ft	Claystone and shale.	High GR.
Lista Formation	100 to 200 ft	Shale/marl.	Unstable formation. Particularly problems were seen when the formation was drilled with water based fluids. Prone to caving.
Upper Våle	20 to 30 ft	Marl.	Low GR, hole stability issues.
Dense Lower Våle	approximately 30 ft in average		Losses due to extensive fracture propagation from the reservoir compaction.

2.6 Operational Window

The operational window, often referred to as the mud window or drilling window, is defined as the difference between the pore pressure gradient and the fracture pressure gradient. If the pressure in the wellbore is less than the pore pressure in the formation the well may collapse or pack off. A wellbore pressure that is lower than the pore pressure may also result in a kick. A kick is an unintentional influx of formation fluids into the wellbore. The worst case scenario is an uncontrolled kick. An uncontrolled kick, called a blowout, can damage the installation, the environment and worst of all the people working in the area. This occurred in the early days of drilling on Ekofisk, which highlights the importance of avoiding high-risk areas. If the pressure in the wellbore exceeds the fracture pressure, the well will fracture and lost circulation may occur (Mikalsen, 2008). This illustrates the importance of having the pressure in the well between the pore pressure and the fracture pressure. It is physically impossible for the pore pressure to exceed the fracture pressure. The operational window will therefore always be equal to or larger than zero, for any orientation and inclination(Kårstad & Aadnoy, 2005). Figure 2-12 is a simple illustration what can happen if the mud weight is not kept within the mud weight window .

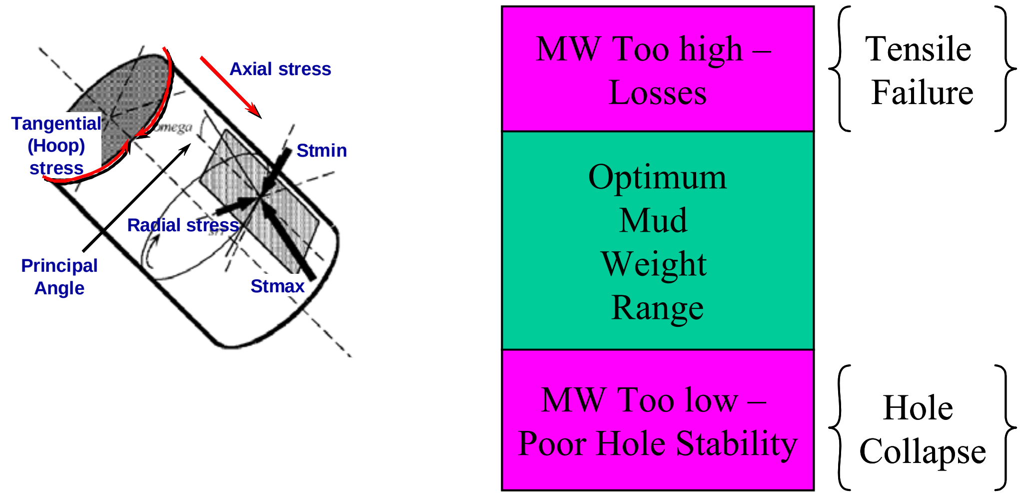


Figure 2-12 Mud window and stresses around an arbitrary oriented wellbore (Bashford, 2008)

2.6.1 Depletion of the Reservoir and Changes in the In-Situ Stresses

Gas and oil reservoirs will experience a drop in reservoir pressure due to production. This drop will change the stress state in the reservoir, which will change the fracture pressure and the collapse pressure, i.e. operational window (Bernt Sigve Aadnoy, 1991).

A simple model to estimate changes in the fracture and collapse pressures due to pore pressure depletion were derived by Aadnøy (1991). The model is based on the assumption that the rock matrix stress increases when the pore pressure drops. The model assumes linear elastic and isotropic rock properties, and that the field depletion is homogeneous. Equations for both the critical fracture pressure and the critical collapse pressure for depleted reservoirs were developed. In this thesis a description of the result when it comes to hydraulic fracturing, will be outlined since the fracture pressure is a limiting factor when it comes to cementing in the Ekofisk and Eldfisk field.

To find the changes in the operational window due to depletion, Aadnøy (1991) used the principal stress principle on a compaction model. The effective stress principle states that the total stress, is the sum of the pore pressure and the rock matrix stress,

$$\sigma' = \sigma - \beta \cdot P_o,$$

where σ' is the effective stress, σ is the total stress, β is the Biot constant, normally ranging from 0 to 1, and P_o is the pore pressure. This principle has its limitations as it determines the stresses with no references to history.

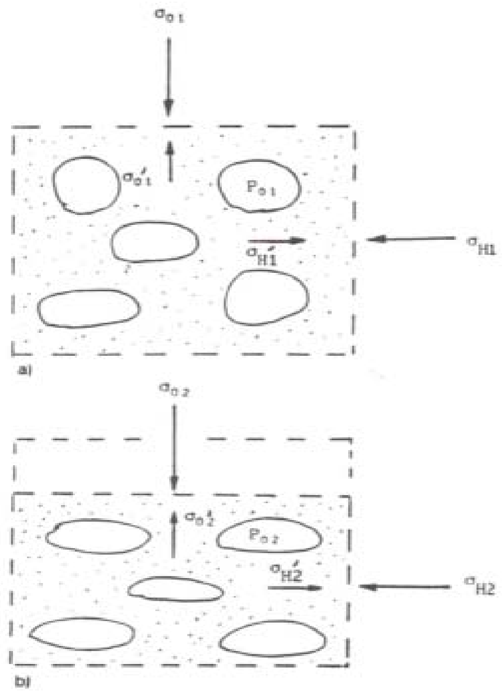


Figure 2-13 Depletion (a) Before depletion (b) After depletion (Bernt Sigve Aadnoy, 1991)

Figure 2-13 illustrates the in-situ stress state before and after a field is set on production. The total overburden stress denoted σ_{o1} acts downwards. The effective overburden stress in denoted σ'_{o1}. The horizontal stresses in the formation are set equal and denoted σ_{H1}. The pore pressure, p_{o1}, acts inside the pores of the rock. The vertical overburden stress is then given by

$$\sigma_{o1} = \sigma'_{o1} + p_{o1}. \qquad (2.1)$$

Throughout the life and production of the well the pore pressure will drop. The overburden stress after depletion is,

$$\sigma_{o2} = \sigma'_{o2} + p_{o2}, \qquad (2.2)$$

where

σ_{o2} is the vertical overburden stress after production,
σ'_{o2} is vertical effective overburden stress after depletion, and
p_{o2} is the pore pressure after the depletion.

The overburden stress is assumed to be the total weight of the overlying material and constant during the depletion

$$\sigma_{o1} = \int_0^D \rho(z) g dz = \sigma_{o2} \, .$$

This means that when the reservoir is depleted, the vertical rock matrix will increase when the pore pressure decreases. The change in vertical matrix can be found by combing equation (2.1) and (2.2),

$$\sigma'_{o2} - \sigma'_{o1} = -(p_{o2} - p_{o1})$$

or,

$$\Delta\sigma'_o = -\Delta p_o \, .$$

This increased vertical matrix stress will due to the Poisson's ratio, *v*, also increase the horizontal stress. The horizontal stress increase is,

$$\Delta\sigma_a = \Delta P_0 (a - 2\nu) \big/ (1 - \nu) .$$

Inserting the horizontal stress change into the general fracture pressure equations gives the corresponding changes in the fracture pressure. The expression for the fracture pressure then becomes

$$\Delta p_{wf} = \frac{1 - 3\nu}{1 - \nu} \Delta p_o \, .$$

In the Ekofisk field the maximum change in pore pressure was found in chapter 2.4 to be 3000 psi. Assuming a Poissons ratio of 0.15 which is a typical factor for chalk, the change in fracture pressure becomes

$$\Delta p_{wf} = \frac{1 - 3\nu}{1 - \nu} \Delta p_o = \frac{1 - 3 \times 0.15}{1 - 0.15} \times 3000 psi = 1941 \text{ psi.}$$

This means that the fracture pressure at the Ekofisk field theoretically has decreased 1941 psi due to the maximum decrease in pore pressure of 3000 psi caused by the production of the field.

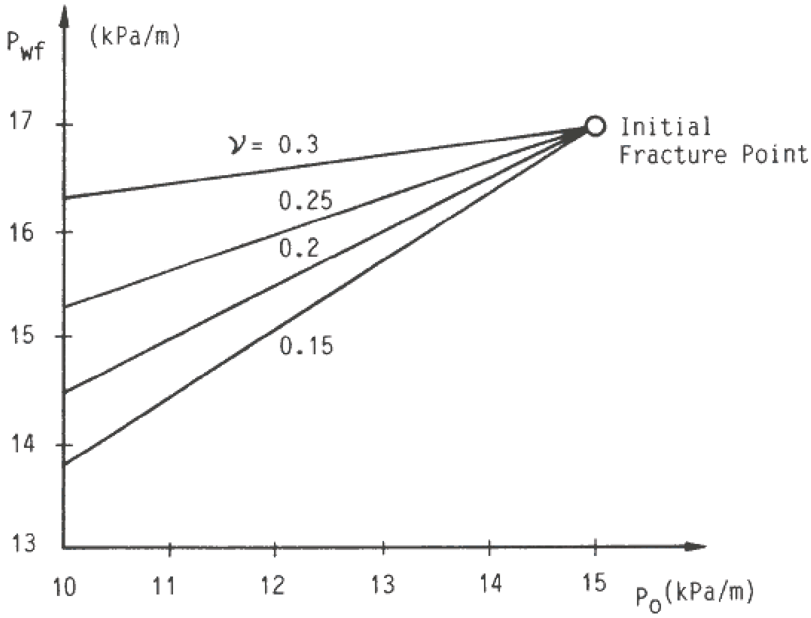


Figure 2-14 Reduction in fracture gradient versus depletion (Bernt Sigve Aadnoy, 1991)

Figure 2-14 shows the predicted changes in fracture pressures versus the pore pressure depletion for a hypothetical case (Bernt Sigve Aadnoy, 1991). In this case, the pore pressure was initially 15 kPa/m and the measured fracture gradient was 17 kPa/m. When the reservoir is produced and depleted the pore pressure will decrease. If the pore pressure gradient of the reservoir decreases to 10 kPa/m, the fracture pressure gradient decreases from 17 KPa/m to 13.8 KPa/m, for a chalk reservoir ($v = 0.15$)

This shows that depletion of the reservoir will decrease both the pore pressure and the fracture pressure. Depletion of a field will, in other word, make the fracturing of the well more critical and collapse less critical.

Considering relaxed depositional environments, the tectonic effects are often neglected, and the horizontal in-situ stress field is assumed to be due to compaction only. This simplification only looks at the hydrostatic or isotropic stress field in a horizontal plane and assumes that the horizontal stresses are equal in all directions. For a deviated wellbore, this implies that there are no directional abnormalities for the same wellbore inclination, and that the same leak-off value is expected in all geographical directions. In a relaxed depositional environment, the overburden stress is larger than the horizontal stresses and the fracture gradient will decrease with increasing hole inclination. However, this ideal situation may not always be the case. Often a more complex stress situation exists. In most real cases the horizontal stress field varies with direction, and there exists two different horizontal stresses. This stress state is called anisotropic which means that the stresses differ with direction. This stress state can be caused by global geological processes like plate tectonics, or more local effects, like salt domes (e.g. the Ekofisk field), topography or faults. Both the Ekofisk field and the Eldfisk field has an anisotropic stress state (Aadnøy, 1996).

2.6.2 Borehole Inclination and Changes in the Fracture Gradient

The maximum value of the fracture pressure may occur in a wellbore inclination different from zero. This is decided by the magnitude of the in-situ stresses and their transformation properties in 3-D space. Kårstad and Aadnoy showed that "If the horizontal in-situ stresses are unequal, and the well is drilled in a direction different from the major horizontal in-situ stress, the behavior of the borehole principal stresses and their shear stresses will result in a maximum fracture equation (2005),

$$p_{wf} = \sigma_x + \sigma_y - 2(\sigma_x - \sigma_y)\cos(2\theta) - 4\tau_{xy}\sin(2\theta) - \frac{\tau_{\theta z}^2}{\sigma_z - p_0} - p_0 .$$

Inclination of the maximum fracture pressure must in general be computed numerically, but the absolute maximum fracture pressure for a well can be computed analytically. The absolute maximum fracture pressure will always occur in direction of the minimum horizontal in-situ stress, and is determined by the singularity of the equation(Kårstad & Aadnoy, 2005),

$$\frac{\partial p_{wf}}{\partial \theta} = 0$$

where p_{wf} is the fracture pressure in the well and θ is the angular position on borehole wall from x-axis (Figure 2-15).

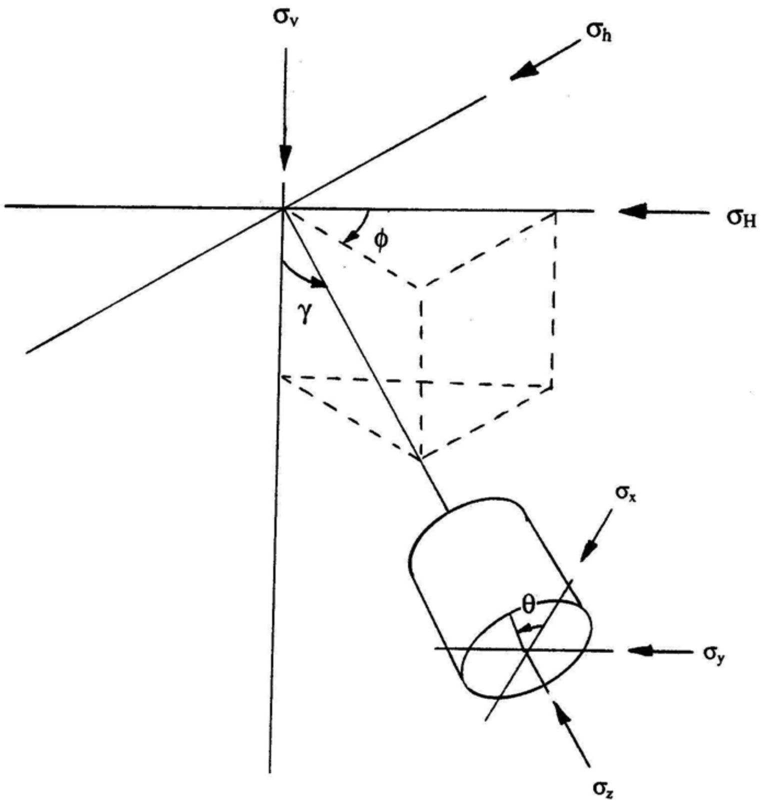


Figure 2-15 In-situ stresses, the transformed stresses and their relative orientation (Bernt S. Aadnoy, 2003)

Under these conditions, the inclination will be determined by the equation,

$$\gamma = \sin^{-1}\left(\sqrt{\frac{(\sigma_H - \sigma_h)(\sigma_v - p_0)}{(\sigma_v - \sigma_h)(\sigma_H - p_0)}}\right).$$

In real cases the shear stresses are often lower than the normal stresses. The squared shear stress components may therefore be neglected. The inclination that gives the maximum inclination pressure is then given by the expression below (Kårstad & Aadnoy, 2005):

$$\gamma = \tan^{-1}\left(\sqrt{\frac{(\sigma_H - \sigma_h)}{(\sigma_v - \sigma_h)}}\right)$$

Hydraulic fracturing of a wellbore is initiated when the stresses change from compression to tension. Increased wellbore pressure will reduce the hoop stress (i.e. change the stress towards tension). Fracturing of a formation will therefore occur at high wellbore pressures.

Kårstad & Aadnøy (2005) showed that the pore pressure/collapse pressure is less dependent on the inclination of the well than the fracture pressure. As a result of this, the fracture pressure dominates the behaviour of the operational window. The fracture gradient is often believed to be decreased with increased wellbore inclination. However, for anisotropic stress states, this might not be the case. The operational window is strongly dependent of the normal in-situ stresses and the direction of the well.

It is physically impossible that the pore pressure in a formation exceeds the fracture pressure. This means that the operational window is always larger or equal to zero. Figure 2-16 shows how the pore pressure and the fracture pressure vary with well inclination. The least value the operational window can have is defined as the stability margin, δ . The stability margin may be determined if the cohesive strength τ_0 is known. τ_0 , represents the degree of cementation of the formation. If stability problem exist, the stability margin is often smaller than the cohesive strength.

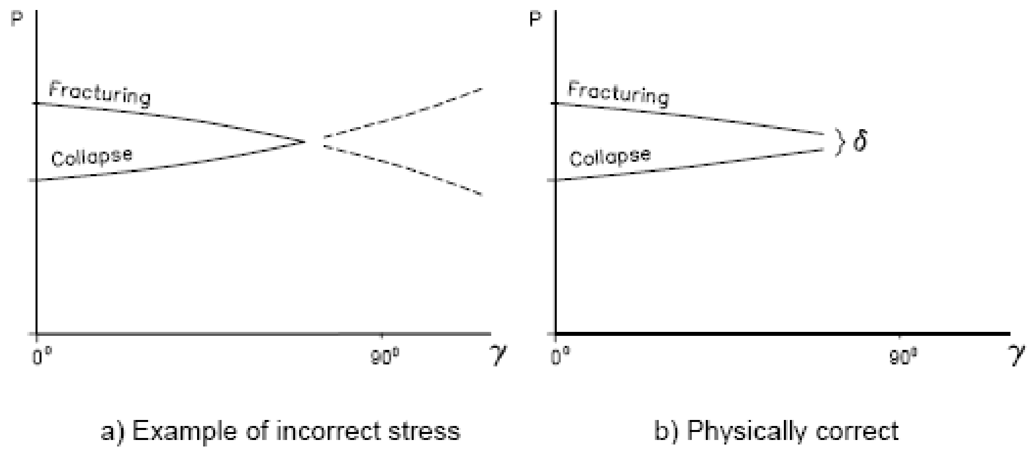


Figure 2-16 Fracturing and collapse pressures versus borehole inclination (Kårstad & Aadnoy, 2005)

2.6.3 Production Casing Setting Depth in the Ekofisk and Eldfisk Fields

The production casing is in this thesis defined as the casing or liner that is situated closest to the production tubing. This thesis has looked at the production casing/liner set immediately above the reservoir. The production casing is usually a 9 5/8” casing when drilling from the Ekofisk X rig or the Eldfisk Alpha rig. The Ekofisk M rig, on the other hand, often runs a 10” liner as their production casing. The Ekofisk K rig (Kilo) and the Eldfisk Bravo rig run 7 ¾” liners. The production casing design studied in this thesis is the 9 5/8” casing and the 10” liner.

The Våle formation is the last formation drilled before the reservoir section and it consists of a mixture of shale and very fine-grained carbonate. The Våle formation is a transitional horizon between the overlying Lista formation which is made up of shale and the more pure chalk of the underlying Ekofisk formation. The Våle formation varies in thickness from 45 ft to 91 ft giving an average of 62 ft. The upper part of the Våle is typically more shaly than the lower part.

The common drilling practice on the Ekofisk and Eldfisk fields is to set the production string about 67 % into the Våle formation. This setting depth is also referred to as top of the petrophysical unit named the Dense Lower Våle formation and it is denser and more competent than the overlying Lista shale and the upper shaly part of the Våle formation. As already mentioned, it comprises, on average, the lower 67% of the Våle formation and has an average thickness of 44 ft. The Dense Lower Våle formation displays a fairly consistent density and thickness over the Ekofisk field, and it is therefore a recommended target for setting the production casing shoe (Bashford, 2008; Mitchell et al., 2004).

The reasons for picking the Dense Lower Våle formation as the setting depth are to hold back the unstable, overpressured Lista formation shale and to allow lower mud weights while drilling the chalks in the reservoir. A clear regression in the pore pressure gradient and the fracture pressure gradient can be seen in this area. The pore pressure contrast between the overburden and the reservoir is very large.

The overburden is normally drilled with a mud weight of approximately 14.5 ppg compared to the reservoir which is usually drilled with 10.5 ppg mud weight. The mud weights that are normally used can be seen in Table 2-5.

Table 2-5 Mud weights normally used in the lower intervals in the Ekofisk and Eldfisk fields

Interval	Section TD [ft]	Mud type	Mud Weight [ppg]	Comments
Production casing	9000-11000	OBM	14,5-15,0	Normally, this section is commenced with 14.5ppg. Stability issues can be resolved with minor additional MW increases (0.2ppg). Severe losses into naturally-fractured hard stringers are common below 5000 ft TVD. Losses have also been observed both with accidental penetration into the reservoir section and also into faults in lower Lista and Våle formations.
Reservoir	15000-17000	OBM	9,5-11,5	The reservoir gradient in areas of Ekofisk can be as low as 5.6ppg but a practical lower limit with OBM is 9.5ppg, any lower and the carrying capacity of the mud and its stability is impaired. Good mud design is required to prevent differential sticking. Higher mud weights for M wells.

The difference in the pore pressure between the Våle formation and the reservoir is increasing as the reservoir depletes. Picking the right setting depth of the production string is therefore very important. If the casing shoe depth is chosen too deep, it forces drilling from the overpressured overburden into the depleted Ekofisk reservoir. This may lead to fracturing of the formation because of too high mud weight and result in extensive losses. Setting the casing too shallow can cause borehole collapse when drilling out the shoe with lighter mud weights that are designed for the chalk in the reservoir section.

Picking the right setting depth for the production string in the Våle formation in the Ekofisk reservoir has long been a challenge and the depletion of the reservoir makes picking a suitable casing point even more difficult. The casing setting depth in this case is very important for drilling performance, production, non productive time (NPT) and safety. The setting depth plays a significant role when it comes to giving a successful cement job. If the cement is pumped into a weak formation the chance of fracturing the formation and thereby losing mud and cement is very high. Losing cement is especially not desirable close to the reservoir where the permeability is high and cement slurry and mud can flow easily and cause big damage to the structure.

As previously mentioned extensive faulting has been observed above the reservoirs in both fields. This may lead to massive losses above the reservoir in the last 200 ft above the casing setting depth. Much work has been done in recent years to quantify the formation`s mechanical properties and the pore pressure and fracture pressure gradients at the setting depth. There have been cases where significant losses have been observed even with the reservoir formation not being penetrated. An overburden study was performed on both the Eldfisk field and the Ekofisk field reviewing the pore pressure, fracture pressure and the rock strength to obtain interpolated mud windows. Different pore and fracture gradient were given for flank, crest, high strength and low strength formation including inclination differences Mud losses and instability problems in the Våle formation does not show a systematic pattern (Mitchell et al., 2004, 2006). Still there exist only one official operational window for the entire Ekofisk field and one official operational window for the entire Eldfisk field. Therefore, the operational windows used in well design and planning are field wide and do not take more localized stress effects into account. In real cases there will, in some areas, be a higher frequency of faulting or evidence of increased stress profiles. These can be characterized by significant amount of casing deformation. In the future, it will be a big benefit to have more area specified operational windows that take the levels of depletion into account in the field, and the changes in the gradients throughout the field. A future aim should be to generate a specific operation window for each well. This is one of the goals for 2009.

One of the main focuses of the geology and reservoir engineer teams is to design trajectories away from the faults at base overburden. If the casing setting depth is in an area with extensive faults, losses are difficult to reduce. Hence reaching the cement target is difficult. Losses and a reduced cement height due to natural faults should be more expected on the flanks of the field than on the crest.

2.6.4 Operational Window and Cementing of the Production Casing in the Ekofisk and Eldfisk fields

A good cement job design is dependent on accurate information about the pore and fracture pressure profiles for the well. In the deeper sections of a well, it is even more important to have a good understanding of the pore and fracture gradients since the pore and fracture pressures in the formation gets closer together, making the operational window narrower. It can be a real challenge, in the deeper sections, to design a cement job such that the job is performed without fracturing the formation and having losses, or without the well flowing during or after the cement job.

Due to the fractured nature of the chalk reservoir and the faulting that is characteristic for it, it is important to verify that the pore pressure and fracture pressure gradients are valid for the target location of the well to be drilled. Some areas in the Ekofisk and Eldfisk fields are significantly more or less depleted than others. The areas in the chalk reservoir that are being pressure supported by the water injection pattern is less depleted than the areas that are not. In recently drilled horizontal sections, differential pressures in excess of 2000 psi have been observed in a short section of the reservoir. This has led to stuck pipe and the need to run a contingency liner to reach the final well objectives(Bashford, 2008). An accurate prediction of the reservoir pressure and reviewing the lower limit and upper limit pressure predictions will allow the engineer to assess the risk of losing the section due to pressure imbalances. The regression of the fracture gradients in the interval immediately above the two reservoirs needs to be well understood both in terms of the relationship between inclination and reduction in fracture gradient and also the differences between a crestal Ekofisk well or a flank Eldfisk well. This regression is critical in the production casing or liner cementation. The ECD during the cement job must be below fracture gradient, if not losses will be taken. Due to the regression of the fracture gradient near the reservoir this zone can become the weakest point (lower fracture gradient than the below the 13 3/8" shoe. During a cement job the worst place where the ECD can exceed the fracture gradient is near TOC. Losses near TOC will result in a lower TOC than planned. If the induced fracture is in connection with the reservoir it can lead to full losses to the production zone in the reservoir the production potential. This makes ECD during cementing a critaical factor of achieving the height of the cement in the annulus by avoiding losses.

To avoid fracturing of the formation, and thereby losing circulation, it may be imperative to ensure that the ECD is low during the cement job. If fracturing can be avoided, the probability of a successful cement job is increased.

2.6.5 Generating the Fracture Gradient Curve

In order to properly evaluate the available data, a common definition and understanding of the data is required. In this chapter the definitions for Formation Integrity Test (FIT), Leak Off Test (LOT) and Extended Leak Off Test (XLOT), used to derive the fracture gradient curves on the Ekofisk field and on the Eldfisk field, will be given. The definitions are used in the overburden study by (Mitchell et al., 2004) and will be utilized in this thesis.

Typically, whether the performed test is of the FIT, LOT, or XLOT variety, the value is calculated based upon the shoe depth or shallowest access point to the formation. Consequently, where large openhole sections exist below the shoe during a test, the depth of the shoe should be used in the calculations and should be the reported depth of the test. For mini- or micro-frac tests where perforations are used to provide access to the formation, the depth of the shallowest perforation should be used in the calculations and as the reported depth of the test.

With the possible exception of the mini- or micro-frac tests, tests performed to assess the fracture gradient of the formation are conducted by combining the hydrostatic head of the mud in the wellbore with the recorded surface pressure of the test. As such, an accurate test requires both a known and uniform mud density from surface to TD as well as accurate surface pressure equipment and recording capabilities. Obviously, these are potential sources of error in the final estimates of the fracture gradients and proper quality control is needed to achieve accurate and comparable results. For the Ekofisk and Eldfisk study, proper quality control was assumed for all the available tests.

A Formation Integrity Test involves testing the well to a pre-set stress limit and then drilling ahead with the knowledge that the tested shoe will at least hold that stress. The test is typically conducted by drilling out the shoe a nominal distance, ten feet is often used, circulating the mud to a constant density, and pressuring the wellbore to a pre-established equivalent mud weight, EMW. The EMW is calculated as the sum of the mud weight in the wellbore and the surface pressure converted to a gradient value at the depth of the shoe. Note that an FIT represents a minimum value for fracture gradient and will tend to be lower in value than either LOT or XLOT results.

A LOT is a step higher in complexity than an FIT. The same basic procedure as an FIT is used in drilling out the shoe and circulating the mud to a uniform density, but instead of stopping the test at a pre-established EMW value, the test is continued until there is an indication that the formation is actually breaking down. Typically, this is considered to occur when a plot of surface pressure deviates from being linear by three points or more. Owing to the apparent initiation of formation breakdown, the LOT test result will typically be higher than an FIT test. Whether the LOT result will be higher or lower than an XLOT depends on the formation.

An Extended Leakoff Test is conducted to intentionally create a fracture in the formation and determine the in-situ minimum horizontal stress. The test is conducted by first pressuring the wellbore sufficiently to completely breakdown the formation and start a fracture. This is confirmed by observing the drop in surface pressure after the fracture is initiated. The wellbore is then depressurized and a second, and possibly a third, injection cycle is performed in order to substantiate the results of the first cycle. Further, depending upon the formation, the well is shut-in between cycles and the pressure monitored to determine the pressure at the point of formation closure, which is equivalent to the in-situ minimum horizontal stress, assuming that the well is located in a normally faulted environment or basin. Because the XLOT completely breaks down the formation and measures the far-field in-situ minimum stress and not solely near-wellbore stress effects, it is often assumed that the XLOT result will be equal to or less than the LOT value. It should be noted that this is not always the case.

Basically, by removing material from an assumed homogeneous continuum, there is less material to withstand the forces being applied and the resulting stress has to increase. These increased stresses are concentrated at the boundary of the created opening and dissipate very quickly away from the opening. Figure 2-17 shows the stress concentrations for the major wellbore stresses and how they dissipate with distance from the wellbore for an elastic solution only. Figure 2-17 shows how the various stresses act on a section of an arbitrarily oriented wellbore.

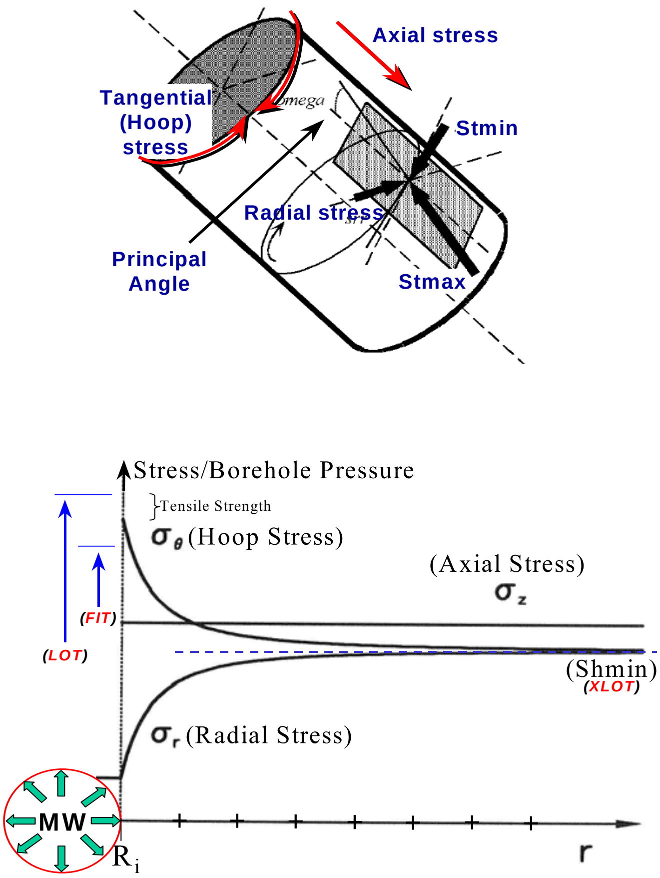


Figure 2-17 Stress considerations around an arbitrary oriented wellbore (elastic solution) (Mitchell, Nagel, Onyia, & VanDeVerg, 2004)

Breakdown of a formation occurs when the pressure in the wellbore exceeds the hoop stress plus the tensile strength of the rock. As shown in Figure 2-17, even if the potential tensile strength of the rock is ignored, the hoop stress will be larger than the in-situ minimum stress,

σ_h. "Since the LOT may be as high as the combined value of the hoop stress and the tensile strength of the rock and the XLOT determines the value of σ_h, it stands to reason that LOT values should, on average, be greater than XLOT values." However, these assumptions to not take into account the non-elastic effects, the influence of a non-circular wellbore and local rock heterogeneities(Mitchell et al., 2004).

2.6.6 Operational Window at the Ekofisk Field

The operational window for the Ekofisk field utilized in this thesis comes from a wellbore stability evaluation of the overburden above the Ekofisk reservoir performed in 2004 (Mitchell et al.)

The Ekofisk overburden fracture gradient and minimum horizontal stress, σ_h, were found through an evaluation of 392 Formation Integrity Tests (FIT), Leakoff Tests (LOT), or Extended Leakoff Tests (XLOT) spanning the period from 1973 to 2003. Of the 392 data points, 244 were LOT's, 130 were FIT's, and 18 were XLOT's (or mini- or micro-fracs). The FIT data show the lowest gradient value, LOT's a bit higher, and XLOT's generally the highest. These test data show that from a value of 12 to 13 ppg at the 20" shoe, the fracture gradient increases to just over 16 ppg between 4000 and 5000 ft TVD-rkb and remains essentially constant to just above the reservoir. Near the reservoir, though not fully resolvable with the data from the research, the fracture gradient is shown to regress. Further, no platform dependence to the data was found; no definitive temporal effect was seen; no spatial component could be seen; and with a very limited subset of the data, neither azimuthal nor inclinational effects were shown to influence the magnitude of the fracture gradient. The the historical FIT and LOT data do not represent the potential breakdown limit of the overburden and, as such, the evaluation of Ekofisk FIT / LOT / XLOT data actually represents the in-situ horizontal minimum stress, σ_h , and not the theoretical maximum breakdown pressure.(Mitchell et al., 2004)

Owing to limited LOT, FIT, or XLOT data near the top of the reservoir, loss data from all the X-wells, in addition to several recent (in 2004) Bravo wells, was reviewed and a quantitative estimate of fracture gradient based upon losses was developed. Most (48 of 51) of these wells experienced losses, many moderate or severe. These findings suggest that the difference between σ_h and the breakdown limit cannot be large. In fact, the data suggest that the breakdown limit and σ_h intersect at approximately 30 to 40 ft above the top of the reservoir. This was confirmed by evaluating the limited XLOT and mini-frac data from the lower overburden(Mitchell et al., 2004).

The evaluation of nearly 392 FIT, LOT, and XLOT tests show that FIT's are on average lower than LOT's which are on average lower than XLOT values. Consequently, the derived "fracture gradient" curve is actually the minimum horizontal stress profile, σ_h, within the overburden(Mitchell et al., 2004).

The existing X-well loss data, as well as the limited XLOT data in the lower overburden, definitively show that the margin between the, σ_h, profile and the breakdown limit narrows immediately above the reservoir and likely intersects. This is the dominant cause for the losses seen in the X-well loss database (Mitchell et al., 2004).

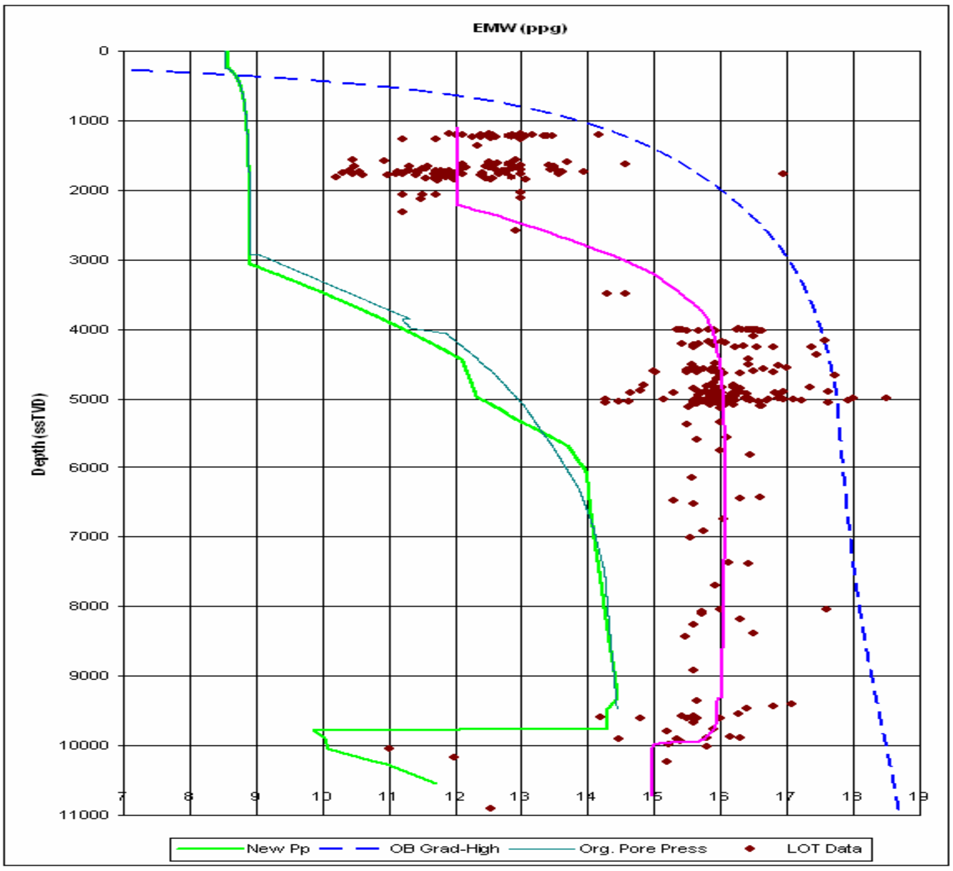


Figure 2-18 Pore pressure and fracture pressure on the Ekofisk Field (Halliburton, 2008a)

The figure above shows the official operational window for the Ekofisk field. The LOT data is plotted to see the fracture strength from drilling experience. Note the wide scatter of the LOT data. This shows that the field is anisotropic. The LOT data also shows an increase with depth as expected due to increased stress state with depth, mainly caused by the overlying rock matrix.

The overburden study from 2004 looked at ECD for losses against the depth above the reservoir. Figure 2-19 shows the result of this research. No direct link was found between the position on the structure and the probability of losses. The vertical axis in the plot shows the depth in ft TVD above Top of Ekofisk (TOE). The horizontal axis shows the ECD when lost circulation occurred.

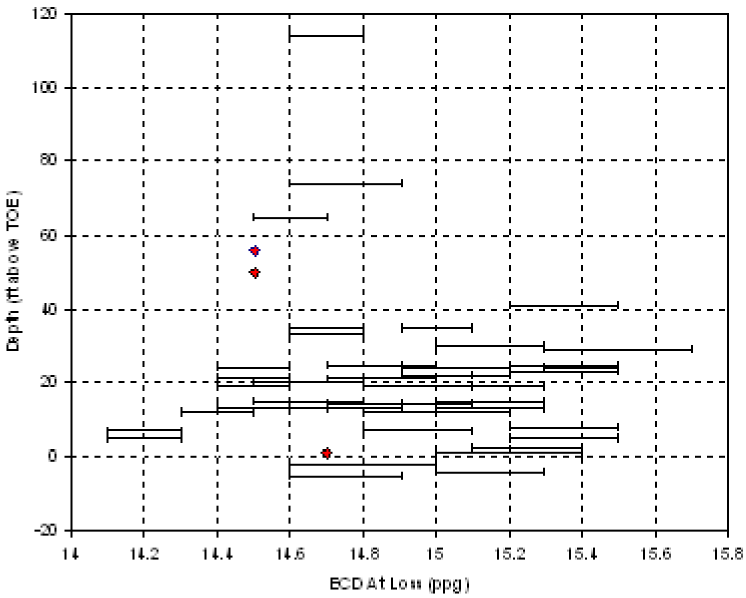


Figure 2-19 EDC at losses vs. depth above TOE(Bashford, 2008)

The overburden study from 2004 shows a clear regression of the formation strength data in the interval immidiatly above the reservoir. This is shown in Figure 2-20. The plot is in TVD ft. Within the last 100 ft immediately above the reservoir, it can be observed that the fracture gradient regresses nearly 1.5 ppg (from 16.1 ppg down to 14.6 ppg or lower). An uncertainty range is given is based on the actual data and is of the size of 0.25-0.5 ppg from the P50 data (red line) (Bashford, 2008).

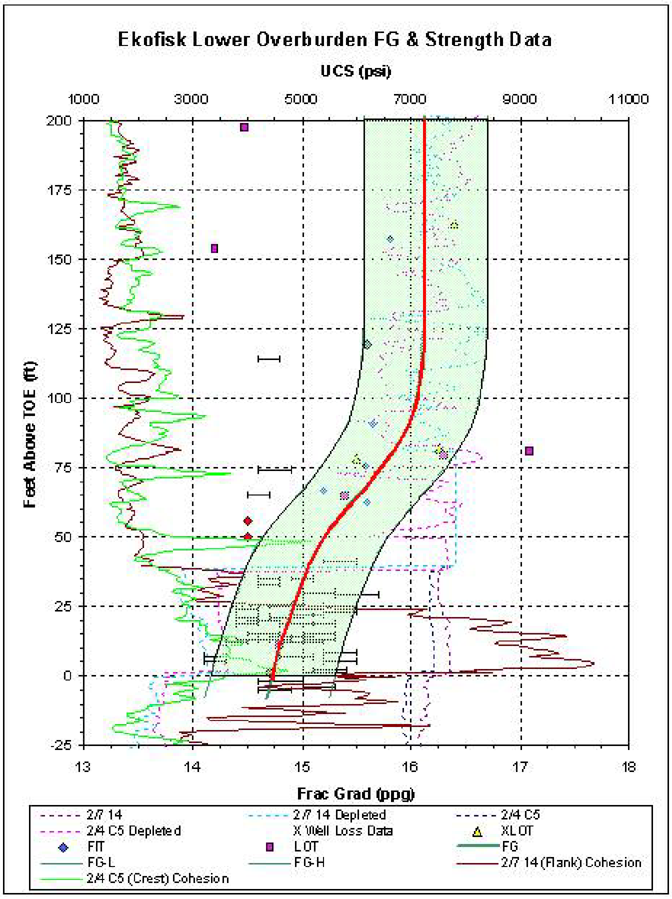


Figure 2-20 Regression in the fracture gradient right above the reservoir (Bashford, 2008)

As mentioned earlier the Ekofisk field is differentially depleted. One reason that losses are common may be the depletion of the reservoir. There are ongoing studies reviewing losses against the level of depletion of the reservoir.

The study also reveals that there is a trend in the variation of the rock strength between the crest and the flanks of the Lista and Våle formations. On the crest, the Våle formation shows relatively low rock strength. The strength of the formation increases when moving towards the flanks. Thus the risk of lost circulation during drilling and cementing are higher for a crestal well than a well with production casing setting depth at the flanks. To reduce the risk of losses a detailed review of potential faulting at the setting depth should be performed prior to drilling. The risk of lost circulation during drilling can also be reduced by good cutting transport and reduced ROP (Bashford, 2008).

The interval to be drilled is the very base of the Lista formation, the upper Våle formation and approximately half of the lower Våle formation. The upper Våle formation consists of claystone and can be weak leading to lost circulation with increased ECD. Fractures and faults that have resulted from subsidence can also be a source for losses. The lower Våle formation grades to a marl and is denser than the upper Våle. In some cases, drilling rates decrease in the lower Våle formation due to the density contrast. This is not expected to be completely definitive in the liner drilling case with a new drillbit. (Bashford, 2008).

2.6.7 Operational Window at the Eldfisk Field

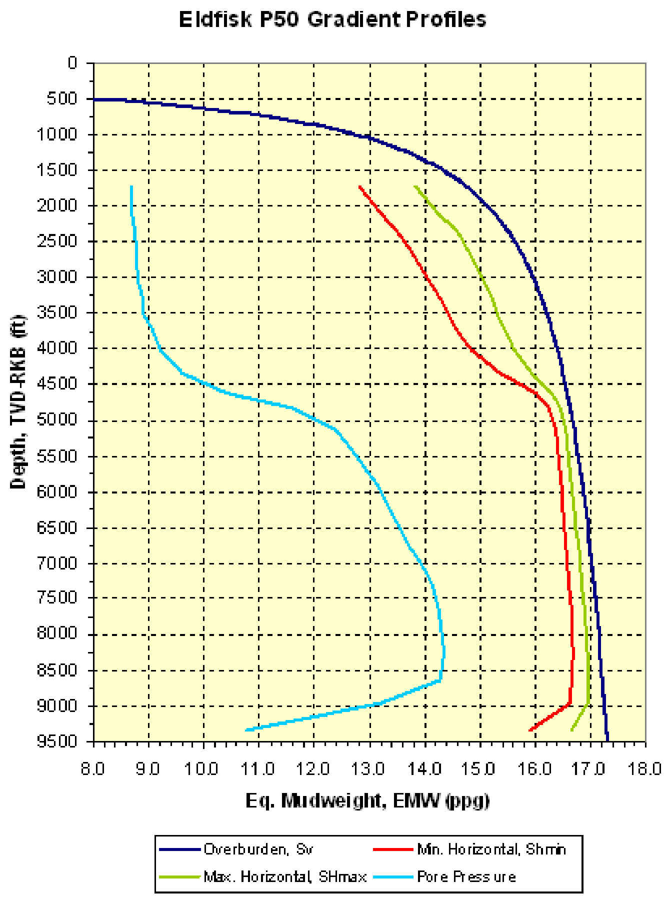


Figure 2-21 Operational window at the Eldfisk field (Mitchell et al., 2006)

Lost circulation is particularly a problem on the Eldfisk field where the regression of the formation strength gradient above the reservoir is more severe. The regression is more severe than illustrated in the currently used operational window seen in Figure 2-21. The 400 ft interval above the Eldfisk reservoir has a regression in the pore pressure of 3 ppg (P50) Figure 2-22). The fracture pressure gradient has a predicted regression of 1 ppg Figure 2-22 to the right (Bashford, 2008). When comparing this to the loss data just above the TOE, it seems like the regression is larger. At its minimum, the new fracture gradient profile drops from 16.8 to 14 ppg (magneta line in Figure 2-23). This makes the mud safety window even narrower close to the reservoir. This finding means that the official fracture pressure curve most likely will underestimate the probability that losses will occur.

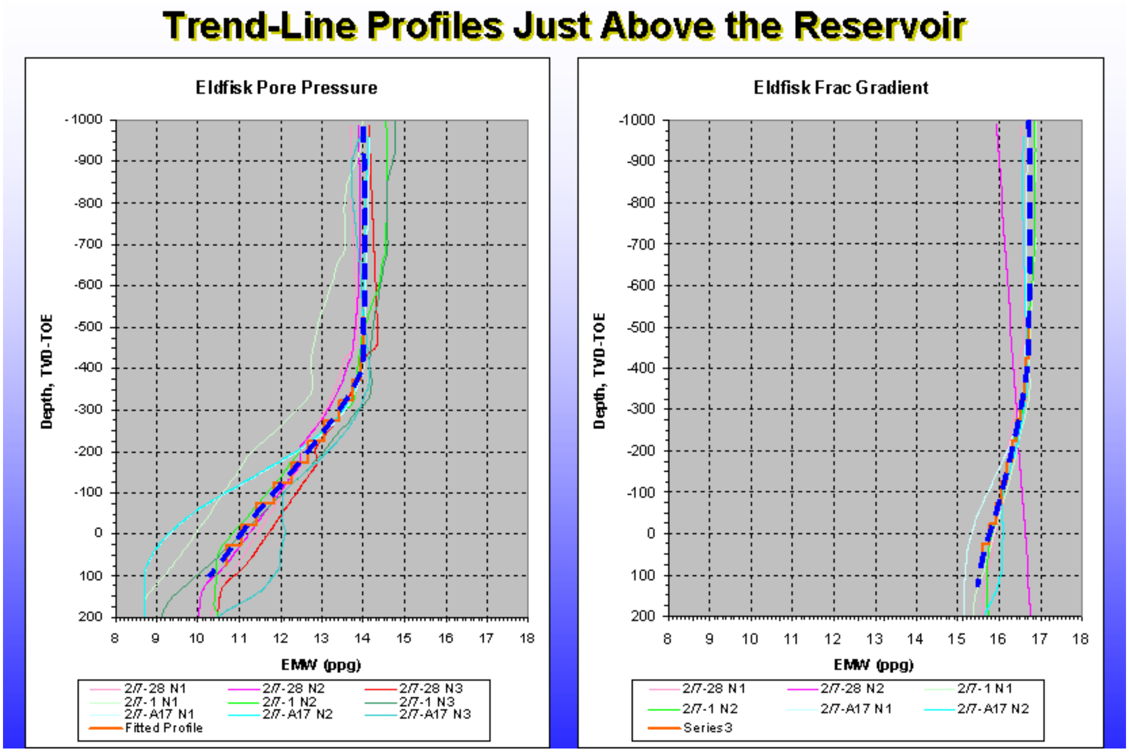


Figure 2-22 Pore pressure and fracture pressure right above the reservoir on the Eldfisk Field

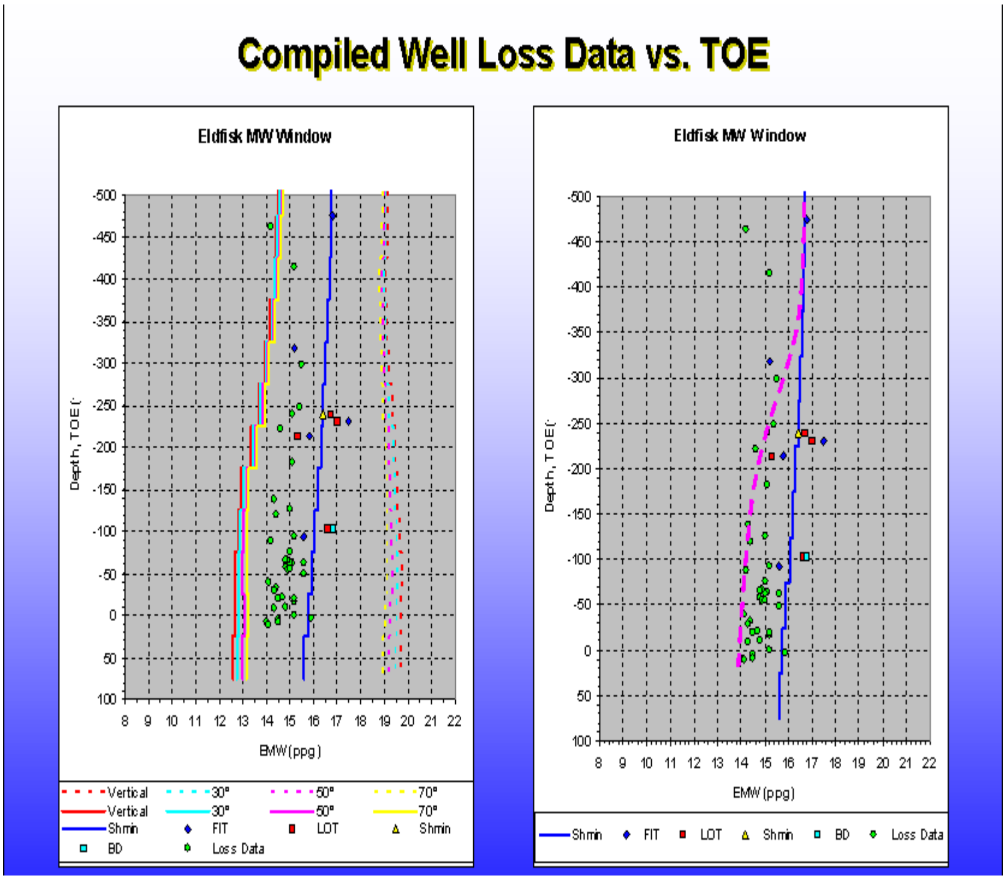


Figure 2-23 Losses right above the reservoir

Stress orientation plays an important role in wellbore stability, especially in cases where there are significant anisotropic stresses. On the Eldfisk field, there is lack of stress orientation data. Eldfisk wells have a great variety in well trajectories. In the overburden study, performed by Mitchell et al., all the wells were assumed to be oriented parallel to the σ_H direction, i.e. the largest horizontal stress (Mitchell et al., 2006).

Figure 2-24 shows an example of a loss/gain plot on four wells on the Alpha platform on the Eldfisk field. It can be seen that losses above 6000 ft are rare and that the main losses come from the intermediate section especially close to the production casing setting depth.

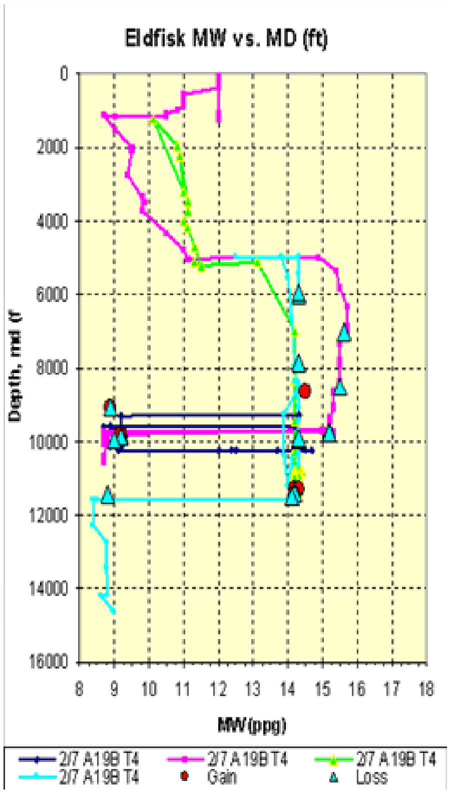


Figure 2-24 Example of losses on 2/7-A-19 B(Bashford, 2008)

The losses that are reviewed are severe losses (Table 3-1). Severe losses can be expected due to penetration of weaker zones or due to mud weight above the fracture pressure gradient of the formation.

One cause of the lost circulation issues on the Eldfisk field may come from drilling through small faults at both the Miocene and Eocene level in the overburden. Approximately 75% of the losses are associated with the Eocene faults. The faults seem small on seimsic, but during drilling history they are shown to be sufficiently large to impact formation and hole stability (Bashford, 2008).

Sonic logs show a significant variation in the rock strength just above the reservoir. This needs to be taken into account when drilling high inclination wells in the future. It will be important to look at wells in the nearby area to gain information about the local formation strength and wellbore stability.

Figure 2-25 shows a drilling case in a low strength formation. It can clearly be seen that there is actually a “negative mud window” for drilling the final 130 ft above the reservoir for wells with an inclination above 30 degree. As stated previously, a negative mud window is physically impossible, see chapter 2.6. The estimated negative mud window may be due to measurement errors or wrong comparison of data. Even though a negative mud window is impossible, a mud window close to zero may occur. The Figure 2-1 thereby indicates that the mud window in a low strength area is very narrow. On the Eldfisk field it looks like the minimum and maximum horizontal stresses have almost the similar magnitudes (Hagen, 2009; Moe, 2009) In 2005-2006 the average inclination through this interval was 70 degree. It is therefore predicted that some wells will be drilled with either hole collapses or with mud losses through induced fractures. Since the study in 2006 assumed that the borehole is orientated along the maximum horizontal stress axis the fracture pressure is a monotonously decreasing function with increasing inclination (Kårstad & Aadnoy, 2005).

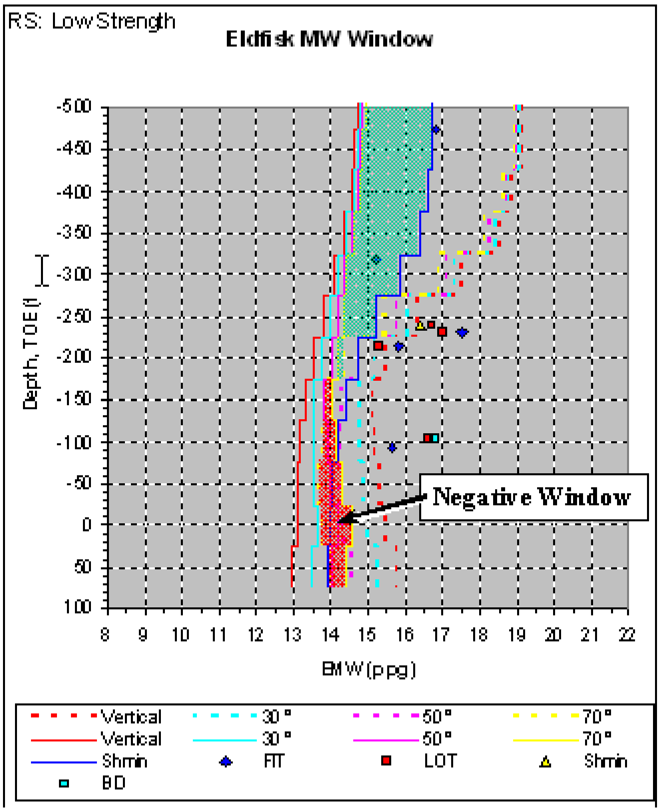


Figure 2-25 Eldfisk m.w window in a low strength formation (Mitchell et al., 2006)

Figure 2-25 illustrates the issues around what mud weight and ECD to use in this interval. It is difficult to lower the mud weight substantially to avoid losses to the formation when the mud window is very narrow. It is in this case therefore especially important to actively manage drilling and cementing procedure. High ROP`s, high tripping speed when running casing, poor hole cleaning and high ECD will all increase the probability that losses will occur.

3 Lost Circulation

Lost circulation is defined by Goins in 1952 as “the total or partial loss of drilling fluids or cement slurries into highly permeable zones, cavernous formations, and fracture or fractures induced during drilling or cementing operations” (Nelson & Guillot, 2006). To control, drill, and complete the well efficiently and safe it is important to avoid lost circulation. Failure on a primary cement job due to lost circulation will not only increase the well cost but it can also reduce the well integrity (Low, Daccord, & Bedel, 2003).

Lost circulation often occurs for the first time during drilling. If the well has already been fractured during drilling, it takes in many cases less pressure to fracture it further. Fractures are cured before the cementing operation and this will strengthen the formation, thus reducing the chance of losses. If the losses are not cured they are expected to occur during the cement process. The ECD is often larger during the cement job the than during drilling. Lost circulation during cementing is a problem that is best attacked if it is prevented before the cement job is performed. These early losses give valuable information on the severity of the problem that exists and thus the problem can be encountered when running the casing or performing the primary cement job (Low et al., 2003). A lot of effort should be put into preventing losses prior to cementing

There are two mechanisms that can cause lost circulation problems during drilling or cementation:

1. Natural losses:
   Natural losses occur when the fluid or cement is lost to a formation that is highly permeable, unconsolidated, fractured, cavernous, or vugular.

2. Induced losses:
   Induced losses is encountered when the pressure of the mud or cement column becomes higher than the formation pressure and induces an excessive pressure that hydraulically fractures the formation and the mud or cement is lost.

Lost circulation problems are often encountered when drilling or cementing naturally fractured formations (e.g limestone), highly permeable formations (e.g. sandstone) or through depleted zones (Low et al., 2003). It is common to classify lost circulation zones in five different categories dependent the formation (Nelson & Guillot, 2006) :

1. Unconsolidated formations
2. Highly permeable/low-pressure formations (depleted zones)
3. Natural fractures or fissures
4. Induced vertical or horizontal fractures
5. Cavernous and vugular formations

The drilling industry has a standard classification of the severity of lost circulation (Nelson & Guillot, 2006). This classification is presented in Table 3-1

Table 3-1 Type of losses

Type of losses	Severity [bbl]
Seepage (minor)	< 10
Partial (Medium)	10 to 100
Severe (massive)	100 to 500
Total (Complete)	>500

If losses are encountered due to the ECD`s during drilling or casing running, it will have an impact on the hole cleaning of the well. To overcome this and reduce the losses, the flowrate can be reduced. This may again result in poorer holecleaning and increase the amount of cuttings in the hole. In turn, the ECD will become higher due to the cuttings and a vicious circle is started.

3.1.1 Lost Circulation Material

The oil industry has developed three basic types of agents to combat lost circulation depending on the operational phase of the well (Suyan, Banerjee, & Dasgupta, 2007) :

1. Bridging agents
2. Gelling agents
3. Cementing agents

Lost circulation material (LCM) can be added to the cement slurry if lost circulation problems are not cured before the primary cement job or because the problem are likely to occur because of the cementing constraints (Low et al., 2003). The LCM is then normally added in dry form to cement blends. It is important that the concentration is kept below a critical point to avoid plugging of stage tools and float equipment. Usually, a lost circulation material can bridge a fracture that is three times its own diameter. The lost circulation material should be strong enough to bridge and not crush. The specific gravity of the LCM can cause the particle to float or sink in cement slurry.

“There are three main types of LCM: Granular, lamellar, and fibrous. Fibers are one type of bridging material that form an interlocking net over the pores or fractures and prevent the other particles in the fluid from passing through” (Low et al., 2003)

3.1.2 Lost Circulation during Primary Cementing

Before the cement job is performed, efforts should be put down to eliminate or significantly reduce the problem by preparing the well in the best manner. If losses during primary cement jobs are anticipated there are two options for remediation. These are described by Nayberg and Linafelter (1984). The first option is to have an ECD below the fracture gradient of the well by reducing the density of the cement slurry, minimize the height of the cement column, or limiting the casing and annular friction pressure during the placement of the cement slurry. The second solution that they presented is to pump a plugging material as a spacer in front of the cement slurry, add LCMs to the cement slurry or use special additives that impart thixotropic properties to the cement slurry (Nelson & Guillot, 2006).

Of the mentioned methods to reduce ECD below the fracture gradient this thesis will investigate and evaluate the possibilities of a reduced density on the cement, and factor s increasing the annular friction pressure during placement of the cement. The effect of reducing the height of the cement column will also be investigated by the use of stage tools.

The density is one of the most important parameter that affects the downhole pressure. This may be reduced by adding one or more cement extenders.

The rheological properties of cement slurries may also be adjusted to reduce the frictional pressure loss during the placement of the cement. This becomes especially critical in narrow annuli. A viscous slurry can here cause very high friction pressures.

Nayberg and Linafelter (1984) presented also another technique that can help reduce the downhole pressure. This technique involves lightening the hydrostatic column of the mud above the top of the cement by injecting nitrogen into the mud. This technique will not be suitable for cementing the production casing due lowering of the hydrostatic mud column will be a risk for well control. This technique may be more suited in shallower sections.

The downhole pressures in potential lost circulation zones can be decreased by using mechanical downhole devices. Such devices can be a stage collar or external casing packers (ECP). Stage collars allow the casing to be cemented in two or three stages, lowering both the dynamic and hydrostatic pressures.

To lower the risk of cement fallback if losses do occur, a special stage collar with a packoff adaption can be used. When expanded, this stage collar provides a seal between the casing and the formation to prevent downward fluid movement (Nelson & Guillot, 2006).

4 Equivalent Circulating Density (ECD)

A drilling fluid's ability to control subsurface pressures is mainly dependent upon hydrostatic pressure. To stop gas and fluid flow from the formation into a wellbore, the hydrostatic pressure of the drilling fluid must be greater than the pore pressure. The hydrostatic pressure is a function of density and depth and can be calculated as;

$$P_h = K \cdot TVD \cdot \rho_{mud} \ ,$$

where K is a correlation factor that is dependent on the unit system utilized. K is equal to 0.052 for the Petroleum system and 0.0981 for the SI system.

This pressure only applies when the mud is static in the well. If the mud is being moved or circulated, an additional pressure, the annular fluid friction, must be taken into consideration. Frictional pressure loss occurs while the slurries are pumped down the casing and up the annulus during cementing operations. Predicting the right frictional pressure losses of cement slurries are important for defining safe circulating pressures to help elude breakdown of weak formations during cement placement. The cement slurry must always be pumped at a flow rate that will attain an ECD that is lower than the fracture pressure gradient of the formation (Ravi & Sutton, 1990). Accurate calculation of friction pressure losses allows complete wellbore hydraulic analysis. The friction pressure is also dependent on the flow regime the cement job is conducted in. In many cases it is desirable to pump slurries under turbulent flow conditions because this gives a lot of extra benefits that can optimize displacement. However, most cement jobs are performed in laminar flow to prevent formation breakdown (Shah & Sutton, 1989). "The critical fluid properties required for the pressure drop correlation, plastic viscosity and yield point, are shown to be influenced significantly by temperature." (Ravi & Sutton, 1990). Determination of the accurate downhole temperature is therefore very important.

There exist different methods for calculating the frictional pressure loss. The magnitude of the pressure will depend upon the type of flow, properties of the fluid, and geometry of the flow system. These parameters can be manipulated to improve cementation. Hydraulic simulations have been performed to investigate these properties.

Equivalent Circulating Density (ECD) is the hydrostatic pressure of the fluid in the wellbore plus the additional annular frictional loss converted the density a non-flowing fluid would have to give in the same downhole pressure. The equation below can be used to calculate the ECD (petroleum system units)

$$ECD = MW(ppg) + \frac{Annulus \Delta P(psi)}{0.052 \times TVD(ft)} \ .$$

The main variable in the ECD calculations is the annular pressure loss and the following factors will affect this variable (Mims, Krepp, Harry, & Russell, 2003):

- Length and wellpath of well
- Annular clearance
  - Hole size
  - Casing
    - Size
    - Casing/liner
    - Centralization
    - Connections
  - BHA (during drilling)
- Flowrate (Flow regime)
- Mud properties
  - Rheology
  - Gel strength
- Cement properties
- Rotation of the pipe
- Swab and surge pressure (mainly before cementation)

Surge and swab pressures will not be a large issue under cementation since they occur when tripping drill pipes or casings in and out of the hole. However, prior to hole cleaning and well preparation, swab and surge pressures can have a large affect. Surge pressure comes from tripping in the hole. It creates a piston force that behaves like drag. This can cause a very high ECD and be especially critical for marginal casing runs. Swab pressure are seen when pulling out of the hole and act in the opposite direction as the surge pressure. The swab pressure will counteract the ECD but it may damage the wellbore due to increased fatigue stress on the borehole wall. When it comes to cementing reciprocation of the liner is sometimes performed to achieve a better cement job. This can result in a surge effect that increases the ECD. Therefore, controlled reciprocation is important to avoid having a too high ECD in the well. The effect of the ECD can be lost circulation if the ECD exceeds the fracture pressure gradient of the formation.

The magnitude of the swab and surge pressure is mainly depended on three factors (Mims et al., 2003):

1. Speed of the pipe
2. Viscosity of the mud
3. Flow-by area around the BHA or the casing

The flowregime and the fluid rheology will affect the frictional pressure loss, thus affecting the ECD. The ECD may have a major impact on whether the cement job is successful or not. If the ECD is too large, the formation may fracture and the cement may be lost, thereby reducing the length of the cemented interval. Some theory about flow regimes and fluid rheology is included in the following sections.

4.1 Flow Regimes

An ideal fluid is a fluid that is assumed to have no viscosity. Even though this is an idealized situation that cannot exist in reality, it can be helpful when approaching engineering problems. In the flow of a real fluid the viscosity must be taken into account. In viscous flow, shear stresses between neighbouring fluid particles will occur when the particles move at different velocities. A fluid flow can also be described as compressible or incompressible. Due to the fact that fluids are relatively incompressible, they are often assumed to be incompressible. There are not only existing different types of flow (real, ideal, compressible or incompressible), but also various classifications of flow. A fluid can for instance be classified as steady or unsteady, rotational or irrotational, supercritical or subcritical and laminar or turbulent(Finnemore & Franzini, 2002).

Laminar, or viscous flow as it is often referred to, can be defined in the following way: "the fluid appears to move by sliding of laminations of infinitesimal thickness over adjacent layers, with relative motion of fluid particles occurring at a molecular scale; that the particles move in definite and observable paths or streamlines and also that the flow is characteristic of a viscous fluid or is one which viscosity plays a significant part(Finnemore & Franzini, 2002)."

The velocity profile in laminar flow can be described by the following relationship (Time, 2007),

$$u(r) = u_{\max}\left[1-\left(\frac{r}{R}\right)^2\right]$$

where

$$u_{\max} = -\frac{1}{4}\frac{R^2}{\mu}\frac{dP}{dz}$$

r is the distance from center of pipe,
R radii of pipe,
μ viscosity,
$\frac{dP}{dz}$ pressure gradient along the pipe.

For laminar flow in straight pipes the velocity profile across the pipe is parabolic. The flow velocity is zero at the wall and is increasing to a maximum at the center equal to twice the mean velocity (Schlumberger, 2009).

Turbulent flow occurs at high flow velocities and is characterized by irregular motion of a large number of particles during a brief time interval. In turbulent flow the velocity profile is often expressed based on the power law form (Finnemore & Franzini, 2002; Time, 2007):

$$u(r) = u_{\max}\left[1 - \frac{r}{R}\right]^{n}$$

where

n ranges from 1/5 (weak turbulence) to 1/7 (strong turbulence),
$u_{\max}$ is the maximum velocity,
r distance from centre of pipe,
R radii of pipe.

Fluid flow velocity is not the only factor that determines whether a flow is laminar or turbulent. The Reynolds number, which is the ratio of inertia forces to viscous forces, can be used to distinguish between the two flow regimes. The Reynolds number can be defined by the following equation (Finnemore & Franzini, 2002; Time, 2007):

$$\mathrm{Re} = \frac{DU\rho}{\mu}$$

where

D is the diameter of the pipe,
U is the velocity,
ρ is the density,
μ is the viscosity.

Roughly, one can say that Re = 2000 is the critical Reynolds number, Re_{crit}, where laminar flow becomes turbulent flow (Finnemore & Franzini, 2002).

4.2 Rheology

"Rheology is the science of deformation and flow of matter."(Dresser, 1972) By studying and performing experiments on a fluid, it can be determined how this fluid will flow under a range of different conditions. This information can be vital designing a circulation system that will accomplish certain desired objectives (Dresser, 1972). A rheology model is used to describe the flow characteristics of the fluid. There exist a number of equations to model the rheological behavior of mud and oil well cement suspensions. Common for all of them is that they are all time independent. The equations vary from the simplest one, describing a linear relation between shear rate and shear stress, to the more complex equations able to describe shear dependent relations (Hodne, 2007).

4.2.1 Newtonian Fluid

The shear stress for a Newtonian fluid is directly proportional to the shear rate

$$\tau = \mu\gamma$$

where

γ is the shear rate,
μ is the viscosity,
τ is the shear stress.

Plotting the shear stress versus the shear rate gives a straight line, where the slope is the fluid viscosity that intersects the ordinate at zero. Figure 4-1 shows the shear stress versus shear rate for both a high-viscosity and low-viscosity Newtonain fluid (Schlumberger, 2009). Newtonian fluids include many of the most common fluids, such as for example water.

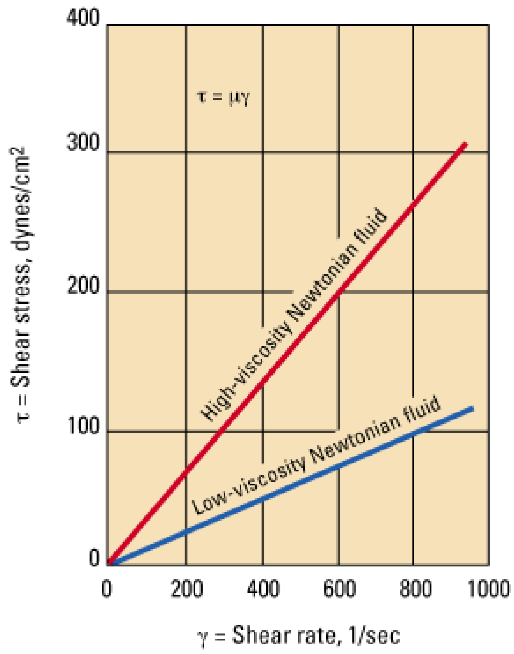


Figure 4-1 Newtonian Fluid (Schlumberger, 2009)

4.2.2 Non Newtonian Fluid

Drilling fluids are non-Newtonian which means that the viscosity is dependent of shear rate. All commonly used drilling fluids are shear thinning which means that the viscosity decreases with increasing shear rate. There exist various models that describe the shear stress versus the shear rate behaviour of oil well fluids. The three most commonly used models are the Bingham plastic, the Power law and the Herschel-Bulkley. These models will be described in the sections below (*Drilling fluids processing handbook*, 2005; Hodne, 2007).

4.2.2.1 Bingham Plastic Model

The Bingham plastic model is frequently used for both drilling fluids and cement slurries. The model is based on the shear stress measured at two different rates. This result in a straight line drawn between these two measured points, with a constant slope defined as the plastic viscosity. The stress value at zero shear rate is defined as the yield stress, also often referred to as the yield point (YP) (Hodne, 2007; Schlumberger, 2009).

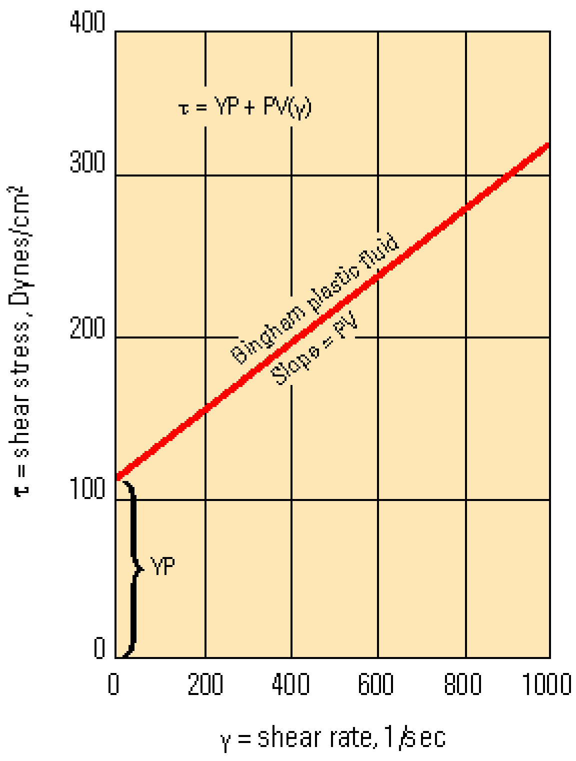


Figure 4-2 Bingham plastic fluid (Schlumberger, 2009)

A Bingham plastic material behaves as a rigid body at low stresses, but flows as a viscous fluid at high stresses. This model is used as a common mathematical model of mud flow in offshore engineering. For a Bingham material there is no flow until the shear stress, τ exceeds a critical value called the yield stress τ_0 .When this critical shear stress is exceeded, the material flows as a Newtonian fluid with shear stress increasing linearly with increasing shear rate. The Bingham plastic model is the defined by the following relationship (Halliburton, November 2008),

$$\gamma = \begin{cases} 0, \tau < \tau_0 \\ (\tau - \tau_0)/\mu, \tau \geq \tau_0 \end{cases}.$$

Examples of materials that shear constantly at shear stresses above a yield stress, i. e behave according to the Bingham plastic model are:

- bentonite drilling mud (approximate)
- cement (approximate)
- many plastics
- mayonnaise

The Bingham plastic model over-predicts the YP. The usual procedure is to do high shear rate viscosity measurements. These measurements reveal that the Bingham model overestimates the low shear rate viscosity for most drilling fluids (Halliburton, 2008a; Nelson & Guillot, 2006).

4.2.2.2 Power Law Model

The power law model can be expressed by the following relationship

$$\tau = K(\gamma)^n$$

where

K is the flow *consistency index* (SI units Pa·s^n),
γ is the shear rate or the velocity gradient perpendicular to the plane of shear (SI unit s^-1),
n is the flow *behaviour index* (dimensionless).

The quantity,

$$\mu_{eff} = K(\gamma)^{n-1},$$

represents an *apparent or effective viscosity* as a function of the shear rate (SI unit Pa·s).

The power law model is also known as the Ostwald-de Waele model. The mathematical relationship is useful because of its simplicity, but it only approximately describes the behaviour of a real non-Newtonian fluid. The model underestimates the low shear rate viscosity. For example, if n were less than one, the power law model predicts that the effective viscosity would decrease with increasing shear rate indefinitely. This requires a fluid with infinite viscosity at rest and zero viscosity as the shear rate approaches infinity. A real fluid has both a minimum and a maximum effective viscosity that depend on the physical chemistry at the molecular level. The power law model is therefore only a good description of fluid behaviour across the range of shear rates to which the coefficients were fitted. There are a number of other models that better describe the entire flow behaviour of shear-dependant fluids, but in the expense of simplicity. Because of this, the power law model is still used to describe fluid behaviour, permit mathematical predictions and correlate experimental data(*Drilling fluids processing handbook*, 2005; Halliburton, November 2008).

Power law fluids can be subdivided into three different types of fluids based on the value of their flow behavior index (Table 4-1):

Table 4-1 Type of power law fluid (Halliburton, 2008b)

n	Type of fluid
<1	Pseudo plastic (shear thinning)
1	Newtonian fluid
>1	Dilatant (shear thickening)

Quicksand and starch solutions are two examples of dilatant fluids and fracturing gels are examples of pseudo plastic fluids. Dilatant fluids are rare in the oil industry and therefore of limited interest, while pseudo plastic fluids are common and receive considerable attention(Halliburton, November 2008).

The power law model is able to describe the shear thinning behaviour of a variety of cementitious suspensions, but in contrast to the Bingham model it does not predict any yield point (Hodne, 2007).

4.2.2.3 Herschel-Bulkley Model

The Herschel-Bulkley model is a more complex model than the other models described previously. This model is a combination of the power law model and the Bingham model. It can therefore predict both the yield point and describe the power law behaviour (Hodne, 2007).

One of the factors needed to obtain a realistic friction value is the yield stress. The Herschel-Bulkley rheological model provides more realistic yield stress values compared with other models. The Herschel-Bulkley model gives a greater accuracy in calculated predictions of flow regime transition and pressure losses. However, calculations are far more complicated relative to other models.

A Herschel-Bulkley fluid can be described mathematically in the following way

$$\tau = \tau_0 + k(\gamma)^n$$

where

τ is the shear stress,
τ_0 is the yield stress,
K is the consistency factor,
γ is the shear rate, and
n is the power law exponent.

The Herschel-Bulkley equation is preferred before Power law or Bingham relationships because it results in a more accurate modelling of rheological behavior when adequate experimental data are available. The yield stress is normally taken as the 3 rpm reading (using a viscosimeter). The n and K values are calculated from the 600 or 300 rpm values or determined graphically (*Drilling fluids processing handbook*, 2005; Halliburton, 2008b).

4.3 ECD during Cementing

There are many factors that contributes to an increased ECD. The ECD during a cement job is usually lager than during mud circulation due to the increased density of the cement leading to higher hydrostatic density of the fluid in the annulus. This again depends on the type of cement used. For good displacement efficiency the cement should ideally have a higher density and viscosity than the spacer which again should have a higher density and viscosity of the mud to avoid contamination and achieve a good displacement. However, the displacement efficiency concept is complex and is also dependent on the flow regime and the mud and cement rheology, and well configuration. There are many factors that allow control of the ECD. High ECD is often a limiting factor when it comes to the cementing of long casings. To help reduce the ECD there are five important guidelines (Mims et al., 2003) :

- Hole Preparation
    - Good hole cleaning
    - As low mud rheology as possible
    - Lightweight Cement
- Centralization
    - Minimize the numbers of centralizers run as they reduce the flow-by area
    - Ensure good centralization.
    - Use centralizers with large flow-by area
- Use slimmer casing/ liner sizes or drill larger holes, i.e. under-ream
- Run liner and tie-back rather than casing.
    - The liner can be rotated to give a better cement job. The cement can then be displaced with a lower flow rate and still have better displacement efficiency than a full casing.
    - The liner hanger must not contribute to a higher ECD

- Avoid tapered long strings, e.g, a tapered 10 3/4” x 9 5/8” has much higher ECD than 9 5/8”.

5 Well Cementing

Primary cementing is the process where a cement slurry is pumped down into the well and placed in the annulus between a casing and the formation and left there to cure. The main objectives of primary cementing are (Piot, 2009) :

1. Zonal isolation
2. Casing anchor (axial support)
3. Protection against corrosion and erosion
4. Support of borehole walls

The foremost goal of primary cementing is to provide zonal isolation in an oil, gas or water well. For this objective to be achieved a hydraulic seal must be created between the casing and cement and between the cement and the formation, while at the same time preventing fluid channels in the cement sheath. The quality of the cement job has a direct impact on the economic lifetime of the well. In lack of complete isolation in the wellbore, the well may never reach its full producing potential. This makes primary cementing one of the most important operations performed on a well. The primary cementing procedure should therefore be carefully planned and executed (Hodne, 2007; Nelson & Guillot, 2006; Piot, 2009).

The most common way to perform a cement job is to pump the cement slurry down through the casing and up the annulus. The two-plug method for pumping and displacement is commonly used. This method prevents contamination with the mud. A plug is run both in front of the cement slurry and behind it. The cement job is completed when the top plug reaches a landing collar (float collar) in the casing shoe. A pressure increase can then be observed at the surface and will indicate when this happens. The well is then shut in for a certain time period to allow the cement to harden and gain compressive strength before drilling further or completion is started (Nelson & Guillot, 2006).

Other cementing techniques can be applied when various well completion problems occur. Cementing through the annulus, also referred to as reverse circulation cementing, is an example of one alternative technique. Reverse circulation is used when important lost circulation zones or fragile formations occur near the shoe, but at the same time cement is required to seal off an upper interval in the well. This way of performing a cement job is often the last option considered, because the fluid displacement is uncontrolled and the shoe end up not being cemented. Modifications of the float equipment are required to be able to monitor the returns through the casing. For large-diameter casings, cementing through the drill pipe is used instead of the traditional cementation technique. This is referred to as the stab-in technique. When cementing through the drill pipe, the cement is circulated into place by pumping the slurry down one or more small-diameter pipes situated in the annular gap. This technique is often used when losses are expected. The volume lost in a total loss situation will be less using this method (losing drillstring volume compared to casing volume). When cementing the intermediate or production casings, different factors, like well conditions and length of the cementation interval, will have an impact and must be taken into consideration when selecting cementation technique. Usually, the maximum down hole pressure is a limiting factor and determines if the job should be performed in a single stage or multiple stages (Nelson & Guillot, 2006).

Since well cementing began in 1903 many advances have been made in all of the disciplines associated with cementing. Different types of Portland cements can be manufactured expressly for well cementing and make them tailored for the conditions encountered downhole. There exists a wide variety of additives that makes it possible to use durable cement in different downhole environments and conditions. Improved techniques to condition the wellbore before a primary cement job to achieve optimal cement placement and zonal isolation have been developed. Today there exist advanced types of equipment and techniques to properly monitor all cement job parameters. This can be used in planning of the cement job or to evaluate the cement job as it is performed. Such monitoring will increase the chances of a successful primary cement job and avoid costly remedial cementing.

If a Portland cement system of normal density (16.0 ppg) is set successfully into the well, the matrix permeability will be extremely low. Permeability is most likely to be in the micro darcy range. During the lifetime of a well the cement will be subjected to various conditions that can affect the sealing capacity of the cement. One of these conditions is "cracking" caused by thermal or pressure fluctuations in the well. Thermal and pressure fluctuations are caused by the production process. In gas wells for instance, there are very large variations in drawdown and temperature as the gas demand changes. The magnitude and frequency of these production variables will have an impact on how much the casing and cement sheath expand and contract in different ways. These factors will cause stress gradients that gradually crack the cement and the cement integrity will be reduced. Debonding occurs when the bond between the cement and the formation, or the casing and the cement, interface fails. There are several production practices that can cause this debonding. One of the reasons is casing movement as subsidence occurs.

When the reservoir is depleted it can result in a shear failure and a complete failure of the cement sheath. As the reservoir is depleted the rock subsides and moves which causes an effective stress increase around the wellbore resulting in a shear failure(Nelson & Guillot, 2006).

5.1 Portland Cement

Portland cement (PC) is the most important binding material in the world and the most common example of hydraulic cement. PC sets and develops strength due to hydration. A chemical reaction between the water and the compounds present in the cement occurs. Setting and hardening of the cement occurs even under water. The development of strength is predictable, uniform and relatively rapid. The set cement has low permeability and is nearly insoluble with water. Therefore, exposure to water will not destroy its hardness. Such attributes are essential to achieve and maintain zonal isolation.

Portland cement is produced by pulverizing clinker. Clinker is the calcined (burned) material that is the end product in the rotary kiln in a cement plant. The clinker consists of mainly four components. Their normal concentrations in conventional Portland cement clinker can be seen in Table 5-1. The properties of Portland cement are determined by mineralogical composition of the clinker. The content of Aluminate and the Ferrite phase can differ significantly for special cements. Another form of calcium sulphate (usually gypsum) is intergrounded with the clinker to make the final product. The addition of gypsum prevents flash set of the cement. Flash set is a phenomenon where C_3A and C_4AF hydrates in contact with water without real sealing. This can prevent proper placement of the cement in the annulus (Nelson & Guillot, 2006).

Table 5-1 Mineralogical composition of classic Portland cement clinker

Oxicide Composition	Cement notation	Common name	Concentration (wt%)
3CaO • SiO2	C_3S	Alite	55-65
2CaO • SiO2	C_2S	Belite	15-25
3CaO • Al2O3	C_3A	Aluminate	8-14
4CaO • Al2O3 • Fe2O3	C_4AF	Ferrite phase	8-12

There exists currently eight classes of API-ISO Portland cements, designated A to H. They are arranged according to the depth at which they are placed and temperatures and pressures they are exposed to. Class G and H cement is most frequently used in well cementing. In the Ekofisk and Eldfisk field class G cement is used to make the base slurry (Nelson & Guillot, 2006).

5.2 Conventional Silica Blended Slurry

Pozzolans are defined as "a siliceous material which itself possesses little or no cementitious value but when added as small particles and in the presence of water will react chemically with calcium hydroxide at ordinary temperatures to form compounds possessing cementitious properties" (Hodne, 2007) .Silica is one example of a pozzolan that is used in well cementing. Generally there are two types of silica used in well cementing, crystalline silica flour and amorphous micro silica. They are used either as extenders or, most frequently, to prevent strength retrogression when encountering high temperatures in the cementing interval. Portland cement requires the additive silica to maintain a reasonable strength and permeability at elevated temperatures.

Portland cement has tricalcium silicate (C_3S) amd dicalcium silicate (C_2S). Mixed with water both hydrates form calcium hydrate (C-H-S) gel. This C-H-S gel structure can provide good compressive strength for the cement at temperatures up to 230°F. However, at higher downhole temperatures, the Portland cement will undergo changes. Above 230°F, the C-S-H gel will convert to an alpha dicalcium silicate hydrate ($\alpha - C_2SH$), a silica deficient phase, which is a weak and permeable binder. In order to inhibit this effect the lime-silica ratio (C/S) should be reduced, by adding silica materials (Al-Yami, Nasr-Ei-Din, Jennings, Khafaji, & Al-Humaidi, 2008).

Fine silica has been used to prevent deterioration of Portland cement at temperatures higher than 230°F in the oil industry for many years (Eilers & Nelson, 1979). Both the Eldfisk and Ekofisk fields have developed standard cement recipes over the lifetimes of the fields. At the Ekofisk field the X-platform started using silica blend cement in 2006. Due to the subsidence issues experienced it had been standard practice not to include silica flour in the cement blends. The reason was that the cement would degrade over the life of the well allowing the production casing to "slip" past the formation when subsidence occurred. The effect of this

lack of long term cement zonal isolation combined with the previous practices of only cementing the production casing with a short cement column, is annulus pressure issues in the majority of wells within the field. Adding silica to the cement used on the production string on Ekofisk has been a success. There are not reported any operational issues with the use of the revised blend. In 2008 it was therefore decided that all rigs at COPNO should use this blend as a minimum(Bashford, 2008).
The conventional cement at COPNO is class G cement with 35% (by weight of cement) silica flour. Cement with 35% silica added goes through changes, but the final set cement has a good compressive strength and a low permeability (D. Mueller, 2009a). Inclusion of 35 % silica has proven to reduce hydration shrinkage of the cement as it cures. Plain class G cement exhibits volume shrinkage of 4% (Nelson & Guillot, 2006). By simply replacing a portion of the cement with non-shrinking silica sand the shrinkage exhibited by silica blends is 2.7% or only 68% of the class G behaviour. This difference can be significant for long term zonal isolation if radial hydration cracks can be avoided.

The specific gravity of silica is similar to the specific gravity of Portland cement. The cost of silica is also approximately the same as for cement so adding silica is not a cost issue.

5.3 Cement Additives

The cement must be designed to perform at different temperatures and pressure ranges. In addition, the well cement must be designed to contend with weak porous formations, corrosive fluids, and overpressured formation fluids. Cement additives make it possible to accommodate this wide range of conditions. “Additives modify the behavior of the cement system, ideally allowing successful slurry placement between the casing and the formation, rapid compressive strength development, and adequate zonal isolation during the lifetime of the well” (Nelson & Guillot, 2006). Today, there exist over 100 additives for well cementing. Below the eight major categories of additives used in well cementing are listed (Nelson & Guillot, 2006).

- Accelerators: Chemicals that shorten the setting time of the cement slurry and increases the rate of compressive strength development.

- Retarders: Chemicals that delay the setting time of cement

- Extenders: Materials that lower the density of a cement system, reduces the quantity of cement per unit volume of set product, or both.

- Weighting agents: Materials that increase the density of a cement system

- Dispersants: Chemicals that reduce the viscosity of a cement slurry

- Fluid loss control agents: Materials that control leakage of the aqueous phase of a cement system to the formation

- Lost circulation control agents: Materials that control loss of the cement slurry to weak or vugular formations

- Specialty additives: miscellaneous additives, such as antifoam agents, fibers, and flexible particles

This thesis will focus on the additives that have an effect on the ECD. The additives that have the largest ability to reduce the hydrostatic pressure column are the extenders which has a major effect on the ECD.

5.3.1 Extenders

Cement extenders are used to either lower the density of a cement system or increase the slurry yield, or both. By increasing the slurry yield the extenders reduce the amount of cement required to produce a given volume of set product.

By reducing the slurry density the hydrostatic pressure during cementing will be lowered. In this way the extenders help to prevent lost circulation caused by breakdown of weak formations. In addition, the number of stages required to cement a well may be reduced.

The extenders are normally classified into three categories depending on the mechanism of density reduction and/ or yield increase (Nelson & Guillot, 2006):

- Water extenders
- Low-density aggregates
- Gaseous extenders

This thesis will focus on extenders used to reduce the density of cement slurry to prevent lost circulation.

5.4 Low Density Cements

5.4.1 Foam Cement

Foamed cement was developed in 1970 to obtain cement with a low density and a good compressive strength (Frisch & Graham, 1999). Foam cement was first applied in well cementing in 1979. Foam cement is a system in which a gas, usually nitrogen, is incorporated directly into the cement slurry. The system requires the use of specially formulated base cement slurries to prepare a homogeneous system with high compressive strength and low permeability(Nelson & Guillot, 2006).

Foam cement is normally characterized by its quality, defined as the volume of gas per unit volume of slurry. The quality can be calculated from the following equation(Nelson & Guillot, 2006):

$$Q_{foam} = \frac{V_{gas}}{V_{foam}} \times 100,$$

where Q_{foam} is the quality of the foam cement, V_{gas} is the gas volume and V_{foam} is the slurry voume.

The quality of foamed cement during placement in the wellbore seldom exceeds 70%. This is the lower limit for a fluid to be technically considered to be foam. Nevertheless, in well cementing industry, the term “foam” is used regardless of the quality(Nelson & Guillot, 2006). Foamed cements are normally designed with a gas quality of 15% to 30%. This allows the density of foamed cement to be up to 4.0 ppg less than the base cement being foamed (Dajani, Doherty, & Mueller, 2007).

The quality of the cement is determined by the base-slurry pump rate, foamer and stabilizer injection rate and nitrogen rate. It is the amount of injected gas (quality) that determines the slurry density. Proper selection of the gas content is important as it allows the foam slurry gradient to be placed between the pore- and fracture pressure curve. A formation that has a low fracture gradient or is very permeable, vugular or cavernous gives difficult cementing situations. Such formations are often unable to support the annular hydrostatic pressure exerted by conventional cement slurry. Foamed cement may then be a solution to achieve a better cement job. “The low density of foam cement reduces losses to potential producing zones, and increased well productivity may result.” (Colavecchio & Adamiak, 1987). It is not only the lowered density that helps reduce losses during cementing. The thixotropic and expansive nature of foam together with the structural characteristic of the bubble cell helps reduce the chance of losses to vugular or fractured formations. It will also help reduce fluid loss to permeable formations. This was illustrated by Colavecchia & Adamiak (1987). Their studies showed that lightweight foamed cement slurries result in less cement loss to low fracture gradient Devonian shale formations than conventional lightweight systems using pozzolan extenders.

The knowledge of foam cement rheology is limited. “The rheological behavior of foams is unlike that of other fluids” (Nelson & Guillot, 2006). The differences arise from many factors. “Foam cement is a three-phase system (gas/liquid/solid) with many phenomena occurring at the interfaces” (Nelson & Guillot, 2006). “Foams are compressible fluids; they are heterogeneous and have variable properties under shear. Foams are dynamically unstable, shear history dependent fluids which the bubble structure is continuously destroyed and rebuilt” (Nelson & Guillot, 2006).

Foamed cement is a compressible fluid. The consequence of this with respect to hydrostatic pressure variations is that the foam quality, and therefore the density, varies as the foam circulate in the well (Nelson & Guillot, 2006). The quality decreases and the density increases as the foam moves from the surface to the bottom of the casing. “As the foam moves back up the annulus, the quality increases and the density decreases. The density can be predicted as a first approximation by considering the compressibility laws and the solubility of nitrogen in the base slurry”(Nelson & Guillot, 2006).

One rheological property is known is that the apparent viscosity of foamed cement increases with quality (Nelson & Guillot, 2006). The viscosity of foam cement is a function of base fluid viscosity plus additional viscosity that is proportional to the foam quality (D. Mueller, 2009b). The foam cement has a high apparent viscosity that can help improve the hole cleaning. The shear stress required to mobilize gelled mud can be reached. Foamed cement develops higher dynamic-flow shear stress than conventional cement when pumped. This increases its displacement capabilities (D. Mueller, 2009a). The solid carrying capabilities are improved compared to conventional cement (Green et al., 2003). The figure below shows the difference between a conventional class G-cement with silica and foam cement when it comes to hole cleaning/displacement capabilities.

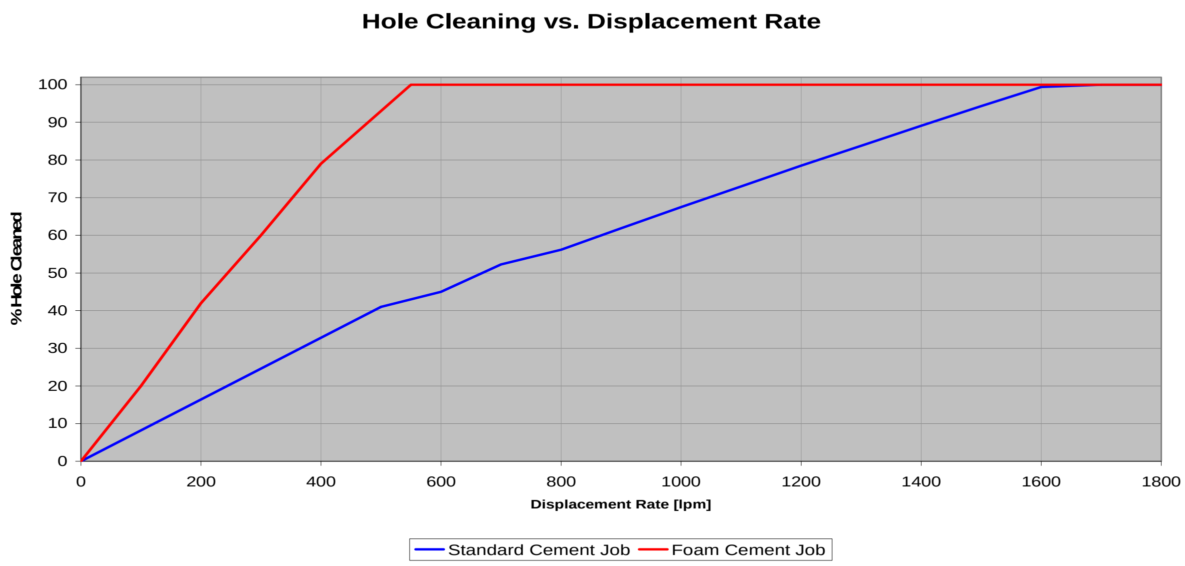


Figure 5-1 Hole cleaning versus pumprate for conventional and foam cement (Halliburton, 2008a)

One of the major benefits with the Foam cement versus conventional G-class cement is the hole cleaning capabilities. Because the foam is more viscous it can be pumped slower than conventional cement and still achieve a good hole cleaning. Figure 5-1 shows that at a displacement rate of 575 lpm (3.6 BPM) the hole is 100% clean with foam and only 42% clean with conventional cement. Since the foam cement can be pumped at a lower speed the chance of losses is lower, because of the lower ECD. The conventional mud needs to be pumped with a much higher speed to avoid contamination during displacement. Higher displacement rate will gives higher ECD. The fact that foam cement generate a higher dynamic-flow shear stress than conventional cement when pumped will increase the friction drop. The disadvantage is that it increases the ECD. Even though the ECD is increased it will still in many cases be lower than the ECD with conventional cement pumped at a higher rate (Green et al., 2003).

Foam cement has several advantages in addition to its low density (Nelson & Guillot, 2006):

- Relatively high compressive strength developed in a reasonable time
- Less damaging to water sensitive formations
- Lower chance of annular gas flow
- Ability to cement past zones experiencing total losses

When it comes to cement additives, like defoamers and dispersants, they tend to destabilize foamed cement, while additives that increase the viscosity or add thixotropy tends to stabilize the foam(Nelson & Guillot, 2006).

There are many factors that affect the stability and zonal isolation properties of foam cement. The stability of foam cement is affected by the foaming agent, the quantity of gas, the chemical and physical composition of the slurry, thermodynamic factors, and the mixing methods and conditions. Stable foams exhibit spherical, discrete, disconnected pore structures with a clearly defined cement matrix. Stable foams are important to achieve a good zonal isolation to stop annular fluid migration.

The mechanical properties of set foam cement are very beneficial in areas where the cemented annulus is subjected to thermal and mechanical loading, like the Ekofisk field. Set foam cement is more ductile than conventional cement and can undergo internal deformations without cracking. This feature of the foam cement may in the longer term help reduce the number of well collapses experienced in the Greater Ekofisk Area (Green et al., 2003).

The flow rate is an important factor when determining the frictional pressure loss and the ECD. Due to the compressive nature of foam cement, the flow rate depends on pressure. The downhole flow rate of foam cement will be different from the one at surface. The downhole flow rate of the foam cement is an important parameter to determine. The flow rate has as mentioned a great impact on the ECD.

A simple way to calculate the downhole volume of cement was given by Dan et al, (1989). The method uses the base slurry and foam quality fraction to determine the downhole volume of cement.

The effective downhole flowrate of foam cement can be calculated using a simple formula,

$$V_{downhole} = (V_{surface}) \times (1/(1 - f)) \qquad (5.1)$$

where

f is the foam fraction (quality),
$V_{downhole}$ is the downhole rate of foam and
$V_{surface}$ is the surface rate of the unfoamed cement slurry.

The formula shows that the downhole flowrate of foamed cement is a function of base slurry (unfoamed) flowrate at surface and the additional rate imparted by the addition of nitrogen (Mueller et al., 1989).

5.5 Mud Removal

Mud removal plays as significant role when it comes to cement quality and zonal isolation and has been a subject of high interest in the well cementing community for many years. The main objective of primary cementing is to provide and complete a permanent isolation of the formations behind a casing. For this objective to be met, the drilling mud and spacers must be carefully removed from the annulus before the annulus is completely filled with cement. A spacer is a viscous fluid used to aid drilling fluid removal during a primary cement operation. The spacer is prepared with a specific fluid characteristic, such as viscosity and density. The rheology is engineered to displace the fluid, reduce contamination between the mud and cement, while enabling placement of a complete cement sheath. Incomplete mud removal can leave mud channels or mud layers on the wells across a zone of interest and thereby favorizing interzonal communication(Nelson & Guillot, 2006).

Drilling mud and its properties have a major effect on the state of the bore hole wall and the amount of cuttings left in the hole. The hole condition prior to cementing and the displacement of the mud during a cement job affect the quality of the cement job. A borehole in good conditions is a borehole that is stable, has a smooth wall with doglegs of low severity, in gauge, free form cuttings and debris, and has a mobile mud that will deposit thin filtercakes in front of permeable zones (Nelson & Guillot, 2006).

It is unfortunately very difficult to achieve such an ideal situation. Therefore, the cement placement techniques are often designed to minimize the influence of poor well preparation. This is a difficult situation and the chances of having losses and a bad cement job is very high with id the hole cleaning is not sufficient (Nelson & Guillot, 2006).

The drilling mud is designed to drill the hole efficiently and the cement job is seldom taken into account when the mud is designed. Therefore it is often necessary to condition the mud to ensure that the mud satisfies the cementing requirements. In COPNO some the upcoming Victor Alpha (VA) injection wells are going to displace the well from the normally used mud (Versatec) to a thinner fluid (Warp) prior to the cement job. This is also recommended for extended reach wells by an external consult research done by K&M.

The basic concept of Warp mud system is to use a liquid suspension of micron sized weighting agents. The weight material is grinded into extremely fine particles. The particle size is about 0.1 to 10 microns, with the majority measuring 0.1 micron. By pre-treating these extremely fine particles with a polymeric coating agent there is no rheology increase. The micron sized weighting agents using Warp technology are much smaller than those the standard API barite (Figure 5-2). The extremely small size, combined with their proprietary treatment, reduces sag potential. The particles are kept better in suspension during connections when a break in circulation is taken (Mi-Swaco, 2004).

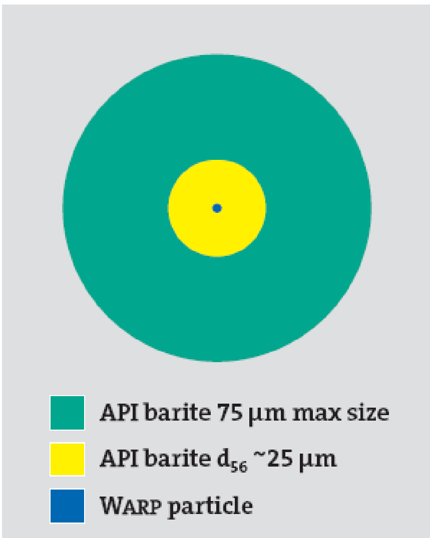


Figure 5-2 Warp particle versus API barite particles (Mi-Swaco, 2004)

Warp mud system from MI is a thinner fluid system that gives a reduction in the ECD. During drilling most conventional wells have an increase in ECD caused by pressure loss of 0.5 – 1.0 ppg. The Warp mud system has shown to give a maximum increase in ECD of 0.3 – 0.4 ppg because of the pressure loss (Bashford, 2008).

The concerns of drilling with the Warp mud system is that it has less hole cleaning capabilities compared to the regularly used Versatec. This is because it is thin and do not have the good lifting capabilities and ability to keep particles in suspension (Axelsen, 2009; Bashford, 2008). But often the increase in flowrate that can be achieved more than compensates for these aspects (Bashford, 2008).

5.6 Casing Movement

Mechanical steps like casing movements are recommended to remove contaminating fluids prior to cementing and to enhance the displacement during cementing. “Rotating the drillstring aids the cleaning of cuttings from deviated boreholes”(Nelson & Guillot, 2006) The same effect is expected on mud circulation and displacement.

Casing movement can be either rotation or reciprocation or both and it improves the quality of the primary cement jobs. Movement of the tubular can hinder cement channeling and improve zonal isolation because the movement can break up areas of stagnant mud. If a casing is not centralized it will be especially difficult to get a good mud removal on the narrow side. The flow will take the easiest way and that is on the wide side. Casing rotation will in these cases be extra useful as it can make the mud on the narrow side move. Casing rotation is also very beneficial if there is gelled mud or solid beds as it can break the yield fluid and make it mobile. Field data has demonstrated the effectiveness of pipe rotation to suspend cuttings and achieve a good mud removal (Nelson & Guillot, 2006).

Rotation and reciprocation along the casing axis may also have secondary movements that have an even greater effect on the mud-circulation effect. When the casing is rotated at high speed it gets an orbital or whirling movement in addition to the rotation around its own axis(Nelson & Guillot, 2006) (Figure 5-3).

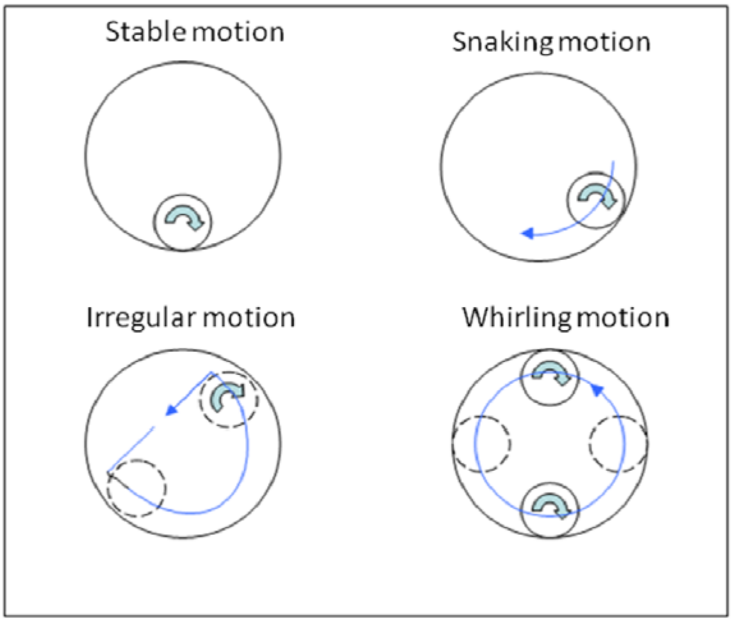


Figure 5-3 Whirling pipe motion during rotation

Another phenomenon that is induced during pipe rotation is Taylor vortices. Taylor vortices are toroidal or helicoidal flows that result from a combination of mean axial flow and azimuthal flow. The induced Taylor vortices increase the wall shear stress and are believed to be one of the main reasons of the increased annular friction pressure seen during pipe rotation.

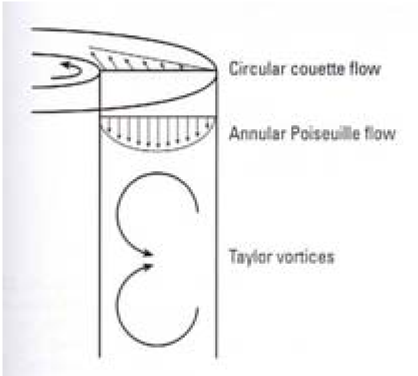


Figure 5-4Taylor vortices (Nelson & Guillot, 2006)

A secondary effect from reciprocation can be seen in deviated wells. When moving the casing up and down the well it comes in contact with a part of the wellbore and this part sees lateral movement in addition to the axial up and down movement.
If a casing or liner cannot be moved before the cement job starts it can often be a sign that something is wrong. The chance for a successful cement job is then low even before the slurry has been mixed (Nelson & Guillot, 2006)Today more and more extended reach wells and complex wells are drilled. The torque and drag in these wells are sometimes too high to rotate the casing during cementation (Mims et al., 2003). This is one of the reasons why Warp OBM (or another thinner mud) is considered in the deeper sections of wells especially for extended reach wells. Reciprocation is particularly difficult in a deviated well. To be able to rotate the casing during a cement job the rig, equipment and wellhead design should be properly designed.

5.7 Multistage Cementing

Multistage cementing is often utilized in weak lower formations. The technique uses a running tool that allows pumping cement at least in two separate sections in the same annulus. The lower section of the casing is cemented conventionally through the casing shoe (Feder, 2001). Two-stage cementing is the most utilized way of performing a multistage job, even though three step cementing can also be performed. This thesis will describe two-stage cementing which is most relevant for the Ekofisk and Eldfisk fields.

5.7.1 Two-Stage cementing

In two-stage cementing, a stage-cementing collar is needed in addition to conventional casing equipment. Stage tools are selective operated sleeves that are strategically placed within the casing string to provide intermediate passage to the annulus. The stage equipment is often used to protect weak formations from excessive hydrostatic pressure. It can also be used to cement widely separated zones and to reduce mud contamination. With two stage cementing the hydrostatic column is divided in two and the chances of fracturing the formation is much lower. By doing the job in two stages the chances of getting the cement to the required level is increased.

One of the most common reasons of stage tool failure is the inability to close the tool after a cement job. It is very important to operate the tool with care to lower the risk of not being able to close it. A tool that is not closed represents a hole in casing. The casing can then not be defined as a barrier element according to the NORSOK standard (See Chapter 5.10)

Stage tools consist of both stage collars and port collars. There exist several types of two-stage tools on the market and the industry does not seem to distinguish between port collars and stage collars. This thesis will give a description of the stage collars and port collars, and highlight the biggest differences between the different stage tools on the market. In general, a stage collar is operated by dropping plugs and cannot be opened again when it is fully closed. A port collar on the other side is operated with a tool connected to an innerstring of the drillpipe.

Table 5-2 below shows a quick comparison between conventional cementing and two stage cementing.

Table 5-2 Stage tool

Conventional cementing	**Stage tool cementing**
Less flexibility and control of cement volume and placement. *The cement can be pumped only through the shoe and it is difficult know where the cement is located unless good quality logs are provided*	More control and flexibility of cement design and placement. *The cement can be pumped in stages which allow more controlled displacement with lower rates. The placement of the tool can be decided which allow flexible placement of the cement. In this way weak zones can be avoided or important areas influx areas cemented back.*
Higher ECD *The ECD in a conventional cement job is higher than with two-stage cementing in the same well due to one stage with two slurries. This makes risk of losses to weak formation higher.*	Lower ECD *The ECD can be controlled and are lower due to lower hydrostatic cement column.*
Limited remedial options and back up. *Higher risk of well abandonment, if a primary cement job is impossible*	Some tools can be mechanically weaker than casing strings
Less downhole equipment	More downhole equipment *More parts that can fail downhole*

5.7.1.1 Stage Collars

Stage collars can be both mechanically and hydraulically operated. The mechanical version of opening and closing the collar needs a hydraulic force. The mechanically operated collars are opened and closed using freefall plugs or pumpdown-closing plugs to select and shift the appropriate internal sleeves. The ports are initially covered by the lower sleeve. After the first cement stage is finished, the lower sleeve is pumped down to uncover the ports. This is done by seating the free-fall or pumpdown opening plug and then applying pressure. The second stage cement job can then be pumped. Once the second stage job is performed the ports are closed by seating and applying pressure to the larger closing plug. When a stage collar is closed it cannot be opened again. For highly deviated holes it is important to remember to use a pumpdown plug instead of a free-fall dart to ensure that the dart reaches its seat. The pressure needed to open and close the collars varies with manufacturers. In general, the pressures required vary between 800 and 1400 psi (Nelson & Guillot, 2006). The stage collars have two clear disadvantages. One of them is that if a stage collar is implemented into the casing string the, it has to be operated prior to any further drilling. The other one is that, once they have been used the plugs and working internal portion has to be drilled out before drilling of the next section (Fritzel & Baker, 1979).

The hydraulic stage tool versions do not require a free-fall plug or pump down plug to open the collar. The tool opens when a shutoff plug bumps against a landing collar. The pressure can then be increased slowly until it reaches a preset shear-pin rating in the stage tool opening sleeve. The pressure needed to close the tool is dependent on the lift pressure of the second-stage cement column plus the shear strength of the pins holding the sleeve open (Nelson & Guillot, 2006).

5.7.1.2 Port Collars

The port collar is another stage tool type. The port collar is mechanically operated from surface by a tool connected to an innerstring of the drillpipe. The port collar can be opened and closed as many times as required and they come with either sliding or rotational valve mechanisms. The sliding sleeves are in general opened with an upwards movement and closed with a downward movement, but it might also do the opposite, like for example the C-Flex. One benefit with the port collar compared to the stage collar is that there are no plugs to use or drillout required. The shifting tools can have cup-type seal to form a conduit from the innerstring to the ports (Nelson & Guillot, 2006).

The critical point of installing a stage tool is the risk of adding a weak link into the casing/liner. If it is not properly closed, it could create a leakage point. The collapse and pressure ratings must be verified and be the same as the rest of the string that it is run in conjunction with.

During the past two years only two wells drilled by COPNO in the North Sea was completed with stage tools to enhance the cement job of the production casing. Both of the jobs used a port collar, but from different service companies. A Full Opening (FO) collar from Halliburton was used in Eldfisk field on well 2/7-A-13B and a C-flex from Peak Well Solutions was run in well 2/4-X-16A. The case histories from these two wells will be given in chapter 6.4.

5.8 Annular Packoff Equipment

Annular Casing Packers (ACP), often referred to as external casing packer (ECP), is an inflatable packer that can be used to help control gas migration. The equipment has expanding rubber elements that pack-off against the formation and creates an impermeable annular barrier. It can be inflated by either mud or cement to form a positive barrier element in the annulus. In this way it can protect areas of the formation from excessive hydrostatic pressure, contamination of fluids or both. An ACP requires a competent formation to seal against.

ACP`s can pack off against the formation by either inflating or compressing the rubber element. The inflatable ACP’s are in general larger and therefore more capable of packing off washed out holes. The inflation of the packer normally starts at a predetermined setting pressure. This pressure should be sufficiently high to prevent premature setting while cementing the well (Nelson & Guillot, 2006)..

5.9 Liner Hangers

Coventional liner hangers

In conventional liner systems the "cone and slip" technology is utilized to anchor the liner to the previous casing. "To accommodate the slip-and-cone mechanism and to provide the strength required to support the liner, a large portion of the available wall thickness is consumed in the liner hanger design" (Jackson, Watson, & Moran, 2008). This makes it challenging and difficult to design new liner hangers with reduced assembly OD. Conventional liner hangers can be delivered with integral packers that ensure isolation between the formation and the surface in addition to the primary cement. The elements on this type of packer can be assembled onto the liner hanger body and secured mechanically. These elements are weak at high flowrates and can be washed out. (Jackson et al., 2008).

Expandable liner hangers

The expandable liner hanger technology introduced a system that used expandable solid liner technology with proven cementing products and service capabilities. The system is constructed by an expandable liner hanger body with an integral packer, a tieback, polished-bore receptacle, a setting sleeve assembly and a crossover sub to connect the assembly to the liner. Elastomeric elements are bonded onto the hanger body. When the hanger body is expanded the elastomeric elements are compressed in the annular space. In this way the liner hanger/ casing annulus is eliminated and there will be liner-top pressure integrity as well as very good tensile and compressive load capacity (Jackson et al., 2008; Nida, Meijs, Reed, & Arnold, 2004).

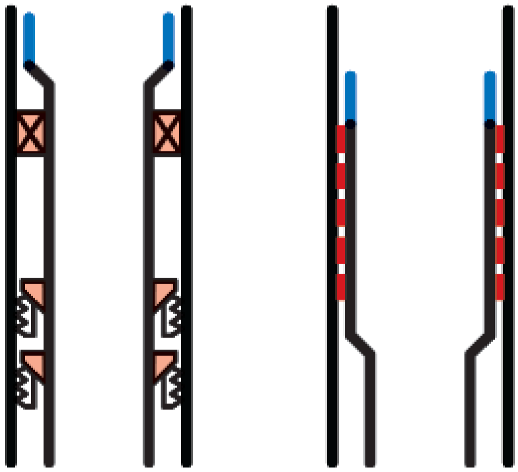


Figure 5-5 Conventional liner hanger (left) compared to expandable liner hangers (right) (Mota, Campo, Menezes, Jackson, & Smith, 2006)

Nida R. et al. showed in 2004 two case studies with expandable liner hangers. The case showed that the liner could be rotated and reciprocated during the hole cementing operations. The expandable liner hanger preserved a full cross sectional bypass area since it stayed in the unset position during cementing and displacement. This gave a constant ECD throughout the cement process.

One example of an expandable liner hanger is the Versaflex liner hanger. The versaflex integral liner hanger/packer is made up of an integral tieback receptacle above or below an expandable solid hanger body. Conventional liner hangers are normally set before the cement operation starts resulting in a reduction of the cross-sectional bypass area. The Versaflex liner hanger, on the other hand, is hold by the drill pipe during the cement job and set after the job is finished. The Versaflex liner hanger can improve the cementing result, by being able to rotate and reciprocate and by having the benefit of better control of pump rates. The hanger body has elastomeric element bonded to it and as the hanger body is expanded, the elastomeric elements are compressed in the annular space.

The first Versaflex liner hanger system was installed in June 2001. The implementation of the Versaflex system has been successfully proven in the M-platform where more than 30 installations have been executed since March 2006. The most successful cases are on the 9 7/8’’ x 13 5/8’’ system expanded in the 13 5/8’’ casing. The case histories of the VersaFlex expandable liner hanger in the Ekofisk M Platform been presented during the Bergen SPE conference in April 2008 (Lahlah, 2009).

Reduced-OD Liner Hanger

A new Versaflex liner hanger is recently designed that has less element and reduced OD. The actual available sizes for the ECD version are 7-5/8 x 9-5/8 and can take liner joints of 47 lbm/ft to 53.5 lbm/ft. The OD is reduced from 8.314” to 8.1” compared to the previous version. Flow analysis shows that a reduction of 0.20 inches will allow for a dramatic increase in flow rate for a given pressure drop across the liner hanger (Jackson et al., 2008). The upper tie-back receptacle is eliminated in the new design.

Flow analysis performed on fluid flow across liner hangers shows that an OD reduction of 0.20 inches will result in a significant increase in flow rate for a given pressure drop. The 9 5/8’’ 53.5 lbm/ft casing usually has an ID of 8.535’’. The original expandable liner hanger, which is designed for this casing has an OD of 8.310’’ giving an annular clearance of 0.1125-in. If this clearance is increased to 0.2175-in by reducing the OD of the liner hanger to 8.100’’ it can have very high beneficial effect. The annular friction pressure is reduced exponentially (not linearly) when the OD of the inner pipe is reduced. In addition, the chance of annular bridging by solids left in the well is significantly reduced. Due to the fact that the liner hanger can be rotated and reciprocated while circulating, also reduce the problems with annular bridging caused by solids.

To design a new liner hanger with reduced OD the following design criteria were established to meet the user requirements

- Reduce the maximum OD of the new tool vs. the original tool by 0.2 inches
- Maintain pressure ratings of the current design (burst and collapse)
- Eliminate the integral tie-back receptacle
- Allow for tie-back to be made on a second run
- Eliminate the setting ball
- Maintain the high torque rating
- Maintain a tool length of less than 60-ft

COPNO uses 9 7/8” 68.8 lbm/ft liner. The new liner type will not strong enough to take the load of this liner joints. COPNO has the need for the low ECD liner hanger, and should check the possibilities for making a low ECD liner hanger for this liner type.

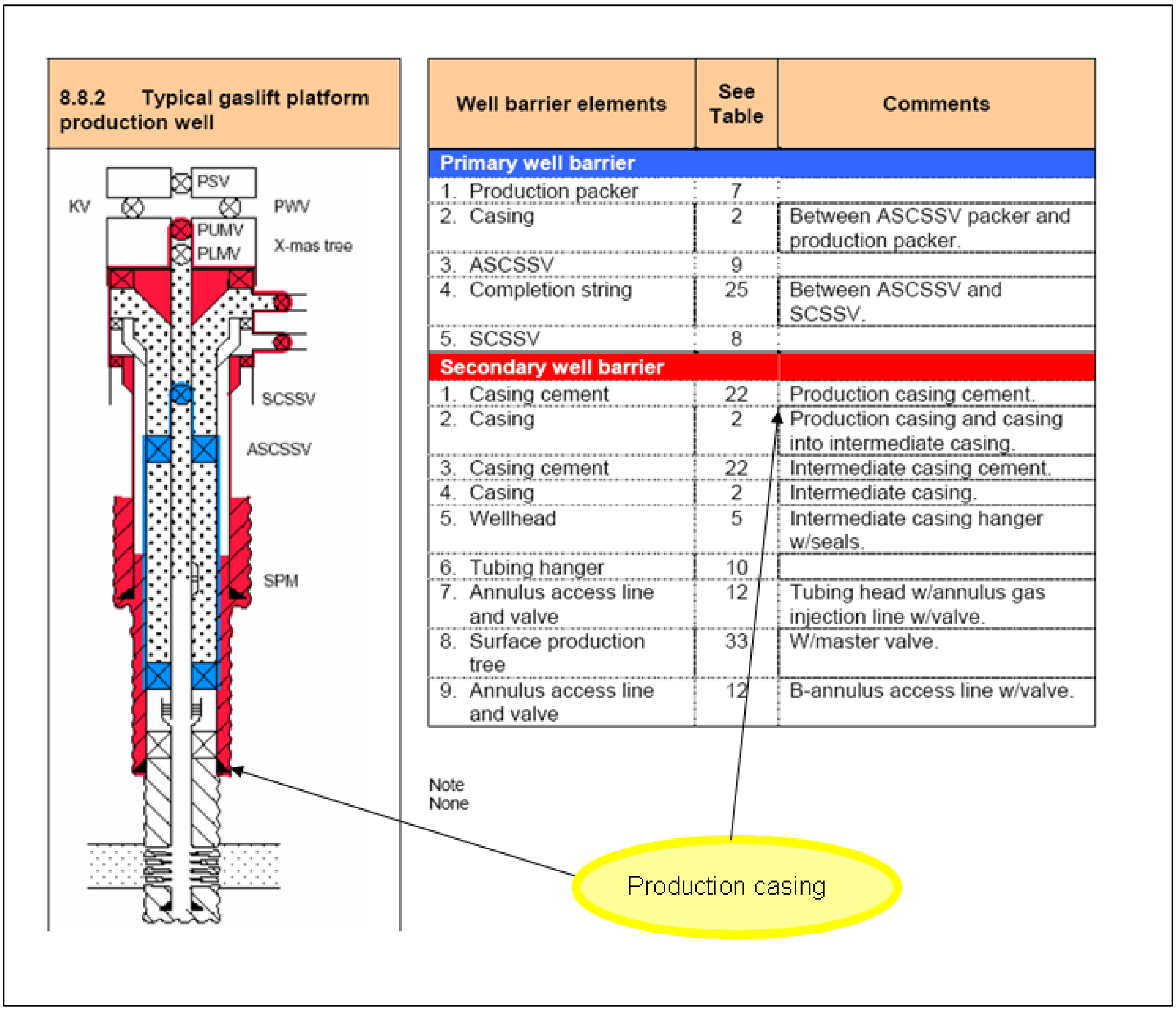
5.10 NORSOK Standard D-010 Well integrity in Drilling and Well Operations

NORSOK D-010 defines well barriers as “envelopes of one or several dependent well barrier elements (WBEs) preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface. The well barrier(s) shall be defined prior to commencement of an activity or operation by description of the required WBEs to be in place and specific acceptance criteria.” A WBE is defined as “an object that alone can not prevent flow from one side to the other side of itself.”

The function of the well barrier shall be clearly defined (NORSOK D-010, August 2004):

“There shall be one well barrier in place during all well activities and operations, including suspended and abandoned wells, where a pressure differential exists that may cause uncontrolled cross flow in the well bore between formation zones.

There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole to the external environment”.



Well barrier elements	See Table	Comments
Primary well barrier		
1. Production packer	7	
2. Casing	2	Between ASCSSV packer and production packer.
3. ASCSSV	9	
4. Completion string	25	Between ASCSSV and SCSSV.
5. SCSSV	8	
Secondary well barrier		
1. Casing cement	22	Production casing cement.
2. Casing	2	Production casing and casing into intermediate casing.
3. Casing cement	22	Intermediate casing cement.
4. Casing	2	Intermediate casing.
5. Wellhead	5	Intermediate casing hanger w/seals.
6. Tubing hanger	10	
7. Annulus access line and valve	12	Tubing head w/annulus gas injection line w/valve.
8. Surface production tree	33	W/master valve.
9. Annulus access line and valve	12	B-annulus access line w/valve.

Figure 5-6 NORSOK Well Barrier schematic (modified (NORSOK D-010, August 2004))

Figure 5-6 shows how NORSOK D-010 describes the well barrier in a typical gaslift platform production well. The primary barrier envelope is illustrated in red. This is made up of primary well barrier elements defined as "the first object that prevents flow from a source". The secondary well barrier envelope consists of secondary WBEs defined as "the second object that prevents flow from a source." From Figure 5-6 above it can be seen that NORSOK defines the cement of the production casing as a secondary well barrier element. The different barrier element that makes up the primary and secondary barrier envelope can be seen in the text box to the left. It further describes the cement in Table A-1 as "This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation".

COPNO has developed internal barrier schematic based on NORSOK D-010. These barrier drawing have some small variances from NORSOK D-010. COPNO starts defining their barriers in the reservoir and includes the reservoir liner as a primary barrier.
NORSOK D-010 states that a casing shall have a 100 m quality cement column above the casing shoe. With good cement means a cement sheath that can provide zonal isolation. The longer the cement column is the better chance of having a zonal isolation is achieved.

COPNO has a requirement of having the TOC 330 ft above the production packer or top of Balder. This requirement is according to the NORSOK standard D-010. COPNO requires more cement in the annulus than the requirement from NORSOK-D-010, dependent on the setting depth of the production packer.

A study of the barrier drawings for the Ekofisk X-Ray and M-wells shows that the TOC of the production casing is overestimated. Many of TOC levels do not take into account losses and excess due to washed out holes. This makes the calculated TOC, in for example the wells that experienced losses during cementing, much higher than actual TOC. The TOC for all the M-wells was gathered from the barrier drawings and compared to the production packer depth. Comparison showed that according to the barrier schematic all the M-wells have the TOC above the production packer setting depth. Further study of each well showed that almost 50 % of the M-wells experienced losses during primary cementing. Only some of the calculated TOC in the barrier schematics included losses. There was for example a well that lost 60 bbls fluid during cement displacement. This was not included as cement loss in the TOC calculations. This can give the wrong picture of the cement height in the annulus. It is therefore strongly recommended that new TOC calculations are done, especially for the production casings. The new calculated TOC should then be included in the COPNO's well barrier schematics.

The verification for having the minimum cement height, can according to NORSOK standard be done by either logs (cement bond, temperature, logging while drilling LWD sonic) or by estimating on the basis of records from the cement operation (volumes pumped, returns during cementing etc)

COPNO does not have a current procedure of running logs after the cement job to evaluate the job. The reason for this is due to the cost and the argument that even though it shows a bad cement job, no further actions to improve this will be done.

To evaluate the cement height on wells in the Ekofisk and Eldfisk fields, calculations were needed. The calculations can be done based on standard capacity calculations or by back-calculations from the final job low flow-rate stand pipe pressure, seen just before the plug bumps. These calculations only give a rough indication on where the TOC is. It is difficult to predict where in the well the losses are taken.

If the TOC is higher or lower than needed several things may have caused that. If the TOC is significantly higher than it should be, it is probable that channelling have occurred, suggesting a bad cement job. If the cement is lower than predicted, one reason may be that not enough cement slurry is pumped during the job due to a greater than estimated hole washout. Another reason for lower cement tops than expected is lost circulation. On the Ekofisk and Eldfisk field the major problem to get the cement to the wanted TOC is, as already mentioned, lost circulation through faults and ECD exceeding the fracture gradient. The faults are tried to be avoided as good as possible by accurate predictions by geologists and reservoir engineers. Still some of these are difficult to avoid due to the number of wells on the two fields making anti-collision an important well planning factor.

As illustrated in Figure 5-7, there are mainly two areas where the losses are more likely to happen due to the ECD exceeding the fracture gradient. This can either be below the 13 3/8" shoe where the fracture gradient is low, or right above the reservoir where the regression in the fracture gradient may be the reason. Near the reservoir there are also may faults that can give natural losses. If the weakest point is right below the 13 3/8" shoe, only mud will be lost and it will not affect the TOC when trying to cement according to COPNO's requirement. Therefore this is the best place to have losses. When it comes to the long term objective of cementing into the previous casing shoe, the cement will not necessarily reach the shoe, but at least cover the Miocene level. The definitely worst place to have losses is near the production casing setting depth right above the reservoir. Then the cement will be lost and height of the cement will be reduced compared with the planned TOC. This is the worst case and most critical for zonal isolation and well delivery. If a well has losses it should always be assumed that the losses are at the shoe as a worst case scenario if logs do not clearly indicate the opposite.

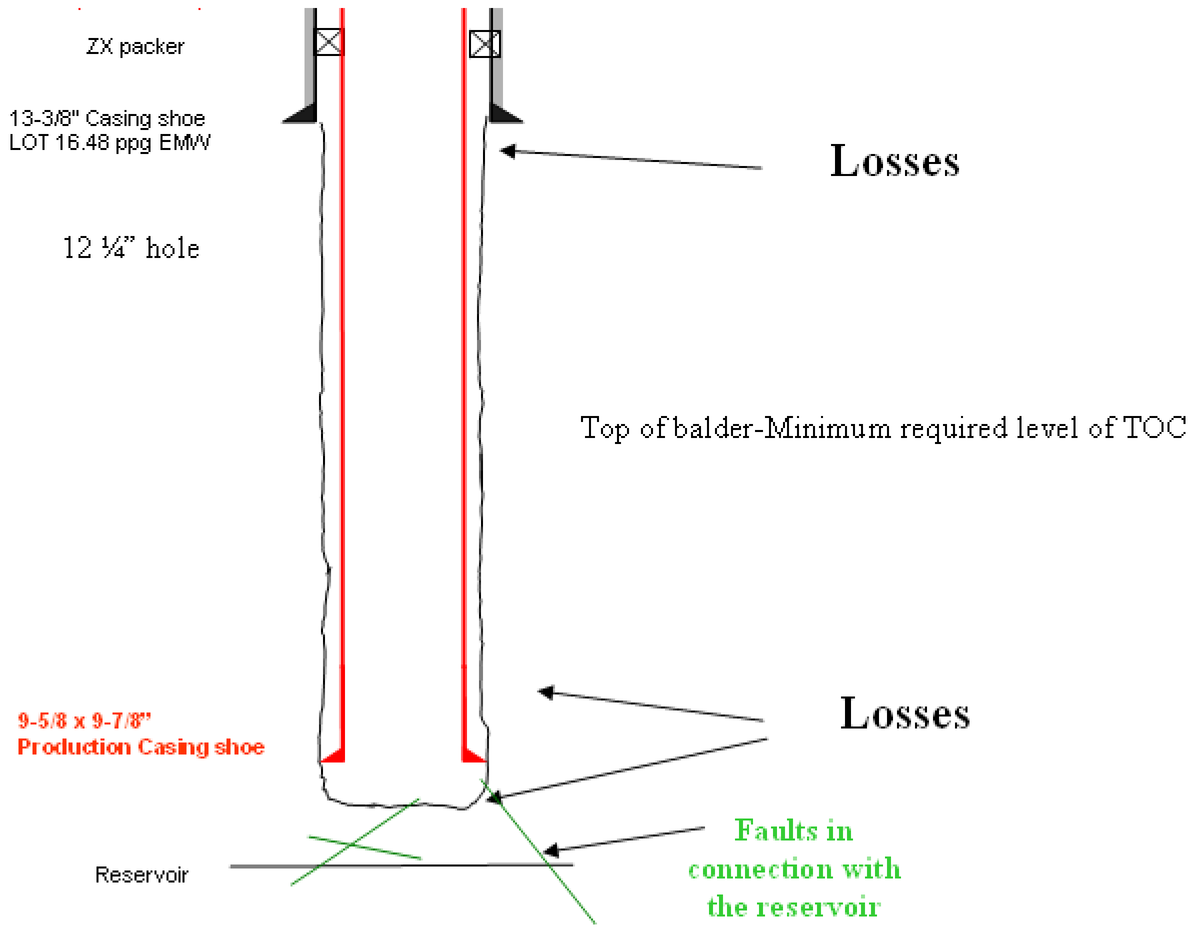


Figure 5-7 Loss location

6 Case Studies

6.1 Introduction

In this thesis different studies have been performed in order to evaluate cement jobs of the casing set immediately above the reservoir at the Ekofisk and Eldfisk fields. The results of different studies were used as a basis to suggest recommendations on how to perform a primary cement job that reaches the planned top of cement. Based on the studies and review of different well cementing techniques, suggestions on how to reach the long term goal of cementing the entire Miocene section were made.

In addition, a deeper analysis of the cement jobs on the Ekofisk M rig was performed. Losses are one of the major reasons why cementing of the 10" production liners on the M-wells have resulted in an incorrect cement top position. Cement job data from the Ekofisk M rig were collected in a spreadsheet and systematically analyzed.

The WELLPLAN™ Cementing-OptiCem module was used for the first time in the North Sea Business unit (NSBU) to look at cementing design analysis. The cement job plans that the cement provider simulates in the Original OptiCem were imported into WellPlan^{TM}-OptiCem for three wells. The outputs in WellPlan^{TM}-OptiCem were very different from the ones in OptiCem for all the wells imported and could not be used for further analysis.

6.2 WellPlan^{TM}-OptiCem

WellPlan^{TM}-OptiCem has been used for the first time in NSBU. WellPlan^{TM}-OptiCem is based on the original Halliburton Opticem cementing software and is a dynamic computer modelling tool that simulates what happens in the well during the cementing operations.

Design of the primary cement operation for the production casing in COPNO's wells is done by Halliburton in OptiCem version 6.2.4. To have a look at the planned cement job the file can be imported in the ConocoPhillips WellPlan^{TM} 2003.16 Citrix application. To be able to import the data the adi file format from Halliburton simulations in OptiCem were converted to otc file format. otc files are compatible with WellPlan^{TM} version 2003.16. Before implementing the files, a cement case had to be built in WellPlan^{TM}. To build a case, different input data are needed:

- Datum level and reference depth
- Well trajectory (depth, inclination and azimuth)
- Hole dimension
- Casing configuration
- Operational window.

The files were then imported into the scratch data base in WellPlan^{TM}. The Opticem module in WellPlan^{TM} should be a display of the data from the original Opticem software. WellPlan^{TM}-Opticem simulations were supposed to be performed. This could not be done as it turned out that the process of importing the file is not straight forward. WellPlan^{TM}-OptiCem should recognize all data, but there are still a lot of improvements needed.

In this thesis three OptiCem files with cement job designs from three wells were imported from Opticem and into WellPlan^{TM}-OptiCem. The OptiCem data was then compared with the data in WellPlan^{TM}-OptiCem. This revealed a lot of differences between the two softwares.

- OptiCem v6.4.2 export does only support the Bingham Plastic model.
- All fluids rheology must be manually re-adjusted in WellPlan^{TM}-OptiCem after the import to the proper models.
- The exported files in Opticem did not calculate all of the foam stages as in the original OptiCem file. This had to be done manually after the import.
- The volumes in WellPlan^{TM}-OptiCem differ from the ones designed in OptiCem, this results in different top of fluids.

Since the import of the data showed errors in WellPlan^{TM}-Opticem it was tried to manually change the cement volumes pumped for the tail slurry to look at the effect on the TOC. WellPlan^{TM}-OptiCem allowed the volume to be changed but did not perform any further calculations, like calculating the TOC. In other cases when changing parameters like well flow, WellPlan-OptiCem^{TM} did calculate the ECD changes.

One of the aims with importing the design data was to compare them to the actual job data. Comparison could give some trends and explain why the cement job did not go as planned. This turned out to be impossible due to lack of data storage.

The work performed reveals that there are no defined recording and storage procedures of the cement job data on the Ekofisk and Eldfisk fields. This thesis was initially going to look at the design data of a cement job and compare it with the actual job data. This was going to be done through simulations in WellPlan^{TM}-OptiCem. The data needed for the simulations was the design file and the file containing the actual cement data as the job was performed. The wells that should have real time data available are the COPNO wells drilled with jack-up rigs, like the M-wells on the Ekofisk field. The jack-up rigs in the Ekofisk and Eldfisk fields have a foam cement engineer out on the rig during each foam cement job. The task of the cement engineer is to perform the job design, follow and record real time data during the pumping phase.

Due to the poor history data storage, it was difficult to track data from previous jobs, including M wells. There were problems getting the ADI file for both the design and real-time data. Therefore, some of the designs were lost due to the lack of back-up. Of the two M-wells drilled in 2009 only one has the 10" liner shoe set in the Våle formation, namely 2/4-M-29 A. Therefore, this was the only M-well where it was possible to get hold of the design and field data for this study.

In the case with the M 29-A well the ADI real time data file (data exported from the Opticem software) has been corrupted. This is because during the recording process of the field data, a wrong template in the Opticem software was used. Also, the time recorded shows a wrong year (1980). After QA/QC the field ADI file of the 10" liner cement job, it was decided that the file was not relevant to be incorporated in the study.

It is necessary to improve the communication between cementing engineers, drilling engineers and the ADT (Applied Drilling Technology) engineers in the ODC (Offshore drilling center). It should be agreed to save and store the latest design file before the job and the real time ADI field data after the job is performed in a common place for post job analysis purposes.

To find the cement density and flow rate during displacement of the cement/mud, the job log of the cement job was needed. The current storage system of the job log reports shows that the procedure for storing the cement jobs is not good enough. Today the procedure is to send one job report offshore to the drilling supervisor and one is stored as a hard copy in Halliburton archive system. To get the cement job log for previous wells the cement engineers at Halliburton needed to scan the hardcopy and then send it over. If all job data were saved in the MaxWell structure it would be much easier to get this data when needed.

This thesis has lead to an improved cementing data management for COPNO wells. New requirements on how to save and store cement data for all future wells drilled by COPNO were sent to the cement service provider by start of June 2009. The requirements are to put all the listed data in the MaxWell structure folder,

- ADI File
    - Latest Opticem design file
    - Recorded ADI real time data.

- Sample test from the laboratory design

- PDF file from the job design/job procedure

- Cement job report

The goal in the future is to make WellPlan^{TM}-OptiCem a part of the engineering package used by the drilling engineers to do their daily tasks, especially monitoring cement quality jobs. WellPlan^{TM}-OptiCem has a lot of features. The well geometry is much more detailed than the OptiCem. One of the main benefits with WellPlan^{TM} is that the cement job can be compared with the other modules like torque and drag, hydraulics, etc. Before this can be done some technical improvements in WellPlan^{TM} and implementation of files are necessary.

6.3 Evaluation of Historical Cement Jobs on the Ekofisk M Platform

6.3.1 Procedure

A spreadsheet with information on historical cement jobs of the 10" production casing was made for all the M-wells. Losses were plotted against the well inclination and the casing setting depth. In addition, rotation of the liner was compared to losses. This was done in order to determine if there is a connection between these variables. Loss is defined as any losses above 10 bbl. The data was gathered from different company sources, both within drilling and reservoir. Most of the data was gathered from the MaxWell Wellview®. This is the database were the well- and drilling operation information is stored like the NSBU Daily Well Operations and Daily Drilling Reports.

6.3.2 Results and Discussion

Table 6-1 Rotation vs. losses

	Loss	No loss
Rotated	6	4
No rotation	8	7

To investigate if there was any trend between rotation of a liner and losses, data from all the M wells that landed the 10"liner in the in the Våle formation was collected. Rotation of a liner will introduce an extra annular friction force. The annular friction force is dependent on the pipe rpm. For the M-wells rotated the rotation rpm varied between 20 rpm and 35 rpm with the majority at 20 rpm. Only one well rotated at 35 rpm. This well had lost 329 bbl during circulation and cementing. Based on only one well it is impossible to draw any conclusion how much rotation of the liner contributed to lost circulation. The reason for not rotating the liner is due to torque and drag limitations. Such limitations occur in long, deviated well paths. Therefore, the wells that did not rotate should have a more complex well path that can result in losses due to a higher ECD and chances of improper holecleaning. Table 6-1 shows losses compared with rotation of the casing liner. There is no clear trend between losses and rotation of the liner on the M-wells. The output is evenly distributed.

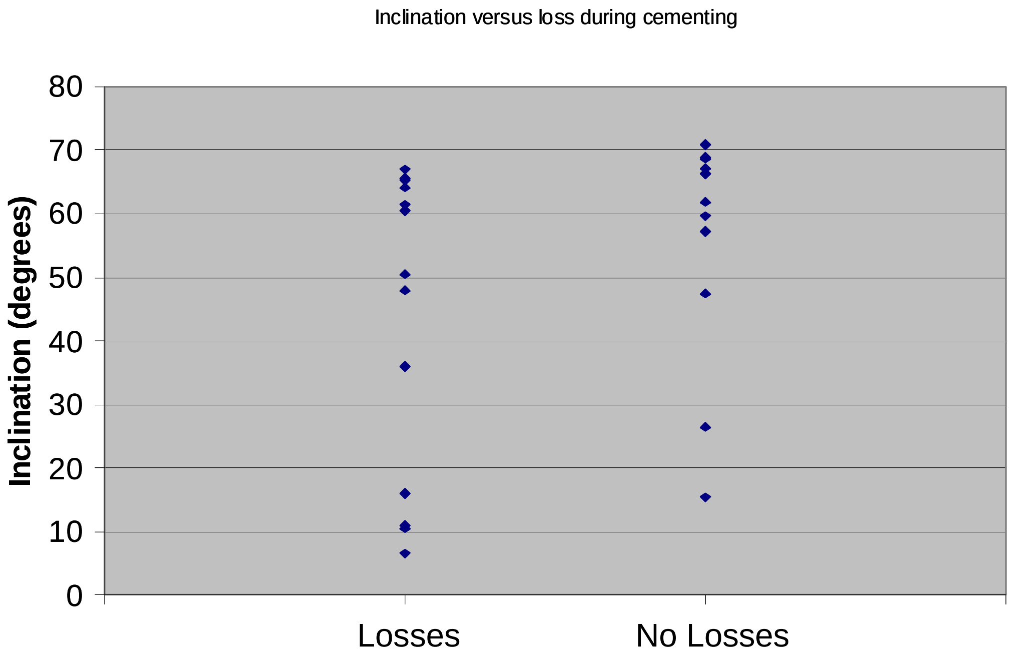


Figure 6-1 Inclination vs. losses

Figure 6-1 shows the inclination at the production casing shoe plotted against losses and no losses during primary cementing. It was expected to see a higher frequency of losses at low inclinations compared with high inclinations. This is due to the fact that poor hole cleaning is much more common in an inclined well. Cutting accumulations in the mud could, during cement displacement, increase both the density and the frictional pressure loss. Hence, the ECD could become higher than the fracture gradient and lost circulation could occur. Still it should be kept in mind that the inclination is just representing the casing shoe and that the well trajectory above may differ a lot due to the fact that many wells drilled in the Ekofisk and Eldfisk field are complex wells. The figure shows that there is no specific inclination that has an overall higher amount of losses. Actually, there are wells with an inclination below 20° that experienced more losses than expected. Also, at high inclinations there seem to be no trend between if a well have losses or full return.

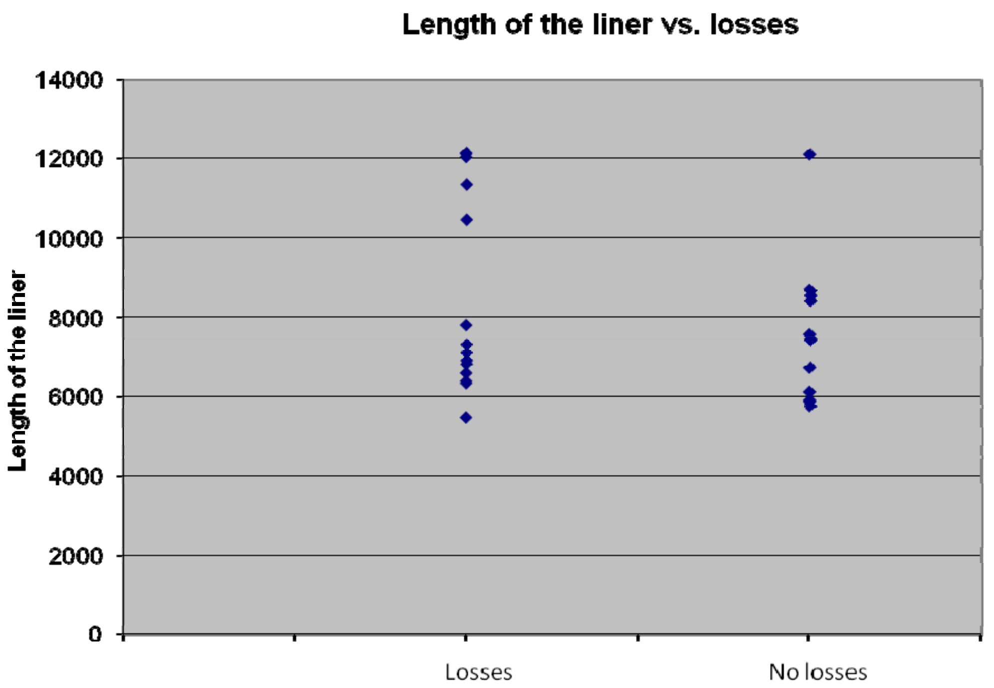


Figure 6-2 Length of the liner vs. Losses

Figure 6-2 shows the length of the liner compared to losses. It can be seen from the figure that the average length of the liner is between 6000 and 8000 ft MD. No clear trend between lost circulations on this length can be seen. However, of the he five wells that have a liner that is longer than 10000 ft four out of five had losses. This can indicate the difficulties of having a long section. The section can be deviated which will give a lower hydrostatic pressure column. However, the annular friction pressure in horizontal will be higher and can contribute to a poor well prepared hole and high ECD during cementing.

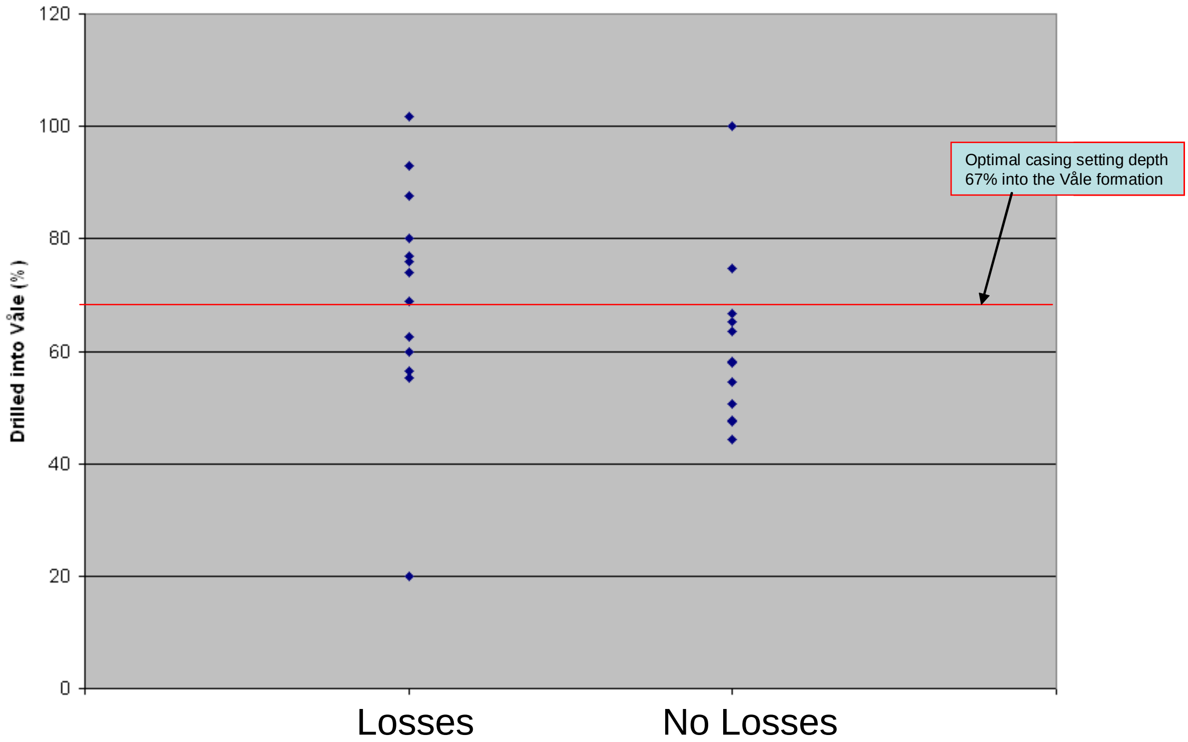


Figure 6-3 Drilled into Våle formation vs. losses

To investigate if there was any trend occurring between lost circulation during cementing and picking the right casing setting depth in the Våle formation different data was collected and plotted. The collected data were formation tops (the Ekofisk formation and the Våle formation) and feet drilled into the Våle formation for every well drilled on the M-platform and the five recently drilled wells on both Ekofisk X and Eldfisk Alpha. Both the Ekofisk and Eldfisk fields have an aim of drilling 67% into the Våle formation. Based on earlier studies of the formation and optimal setting depth of the production casing, the expected trend was that more losses should be taken when drilling closer to the reservoir, due to the decrease in fracture gradient. From the figure above one can see that the majority of wells that are drilled deeper than 67% into the Våle formation results in losses. It can also be observed that most of the wells drilled shallower than the recommended setting depth result have full return. There are two “outliers” in the figure above. One well that was drilled only 20 ft into the Våle formation resulted in losses, while another well drilled 1 ft into the reservoir had no losses.

6.4 Multistage Cementing

6.4.1 C-Flex on Well 2/4-X-16A

One example of a port collar is the Peak C-Flex tool. The C-Flex is a new generation stage tool. It is a sliding sleeve port collar that can be installed as a part of the liner/casing string. This allows access to the annulus after the liner/casing is set and cemented. It can be placed in one or more areas in the casing and liner sections and each section can be simultaneously activated in the same run. The tool gives better control of all fluid pumped, which is very important especially when it comes to cement. The C-Flex can be closed and opened but also permanently locked if required. This will ensure that the C-Flex cannot be accidently opened after being closed. When permanently locked it becomes an integral part of casing or liner. It is designed to meet the casing technical requirements. The 9 5/8” size C-flex is ISO 14310 VO Certified and has the same burst collapse and tensile rating as the 9 5/8” casing.

The C-flex is operated by Peak’s operational cementing tool that is run on a drill pipe. This tool has a high flowrate. The C-flex is operated by push and pull with verification. It takes 12-14 tons to open the C-flex and 6 tons to close it. About 45-50 tons is required to permanently close the C-Flex.

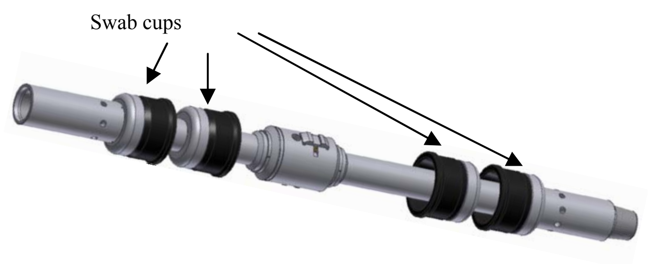


Figure 6-4 Peak C-flex operating tool

2/4-X-16A was the first well in COPNO to run a C-Flex to optimize the cementation of the 9 5/8 “casing. Different options and configurations on how many stage tools and where to place them were discussed to optimize the cement job. The final decision was to run one C-flex positioned below the planned setting depth of the reservoir liner hanger with the purpose of covering up the C-Flex with the reservoir liner.

Prior to running the casing an LCM pill was pumped according to the normal procedure at the Ekofisk X wells, even though there was no sign of losses in this well. While running the 9 7/8” x 9 5/8”casing, the string got stuck 166 ft MD above the planned setting depth. This was most likely due to the reamer shoe run on the casing in combination with the LCM pill. Torque and drag modelling during drilling of the well showed that the hole was not properly cleaned. Based on this analysis and the operational observations it may indicate that the casing was pushing cuttings in front of it.

To see if it was possible to pump the first stage of the cement job an injection test was performed. The well was pressured up to 500 psi right away. It was not possible to pump around the shoe and no circulation was achieved. Therefore, the first stage of the cement job could not be performed.

The next step was to use the C-flex to do the second stage of the cement job. The C-flex was now positioned at 9596 ft TVD at an angle of 53°. The production casing had a good centralization in the well. It had two centralizers both below and above the C-flex tool and one centralizer every second joint of casing up to the depth of the desired TOC. There were no problems opening the C-flex and the cement job went as planned. The cement was pumped with 4.5 BPM at 1200 psi and the job had full returns.

The X-drilling team is not sure that the C-Flex was properly closed after the job. In order to lock the C-Flex, an operating tool engages the C-Flex profile and pulls to a preset amount. During this operation it seemed like the pulling tool came out of the C-Flex. After the drilling crew had pulled the required amount, it was thought that the ports were closed. The drilling crew pressure tested the C-flex to 1800 psi between the cups on the pulling tool. The test was showed no leakage, but when pulled out of the well a flow of 0.5 bbl/min was detected. After a while this flow stopped. There exist two different hypotheses on what the cause of the flow was. One hypothesis suggests that the cement had not hardened and most likely a u-tube effect from the C-Flex was the cause. The hypothesis says that the flow stopped, when the cement hardened (gained 70 BC). What probably happened was that when closing the C-Flex the operating tool came loose from the C-Flex. This may be the case due to the fact that a wrong operating tool with some old dogs where used. The C-Flex was then not properly closed. It is possible that the pressure test to confirm that the tool was closed was done against the casing and not the C-Flex. This can be because of a 4 ft tally difference between the casing and the drillpipe that was later noticed. After pressure testing the C-Flex the next step was to permanently lock the C-Flex. This is achieved by pulling with 45-50 tons. The fact that the C-Flex was not found where it was supposed to be permanently locked is supporting the theory that the pulling tool had moved away from the C-Flex.

Another hypothesis is that C-flex was locked and that the flow detected was due to thermal effects. When a well is circulated the pressure drop creates a heat that enlarges the steel. When the pipe is cooled the steel shrinks and it may have been this shrinkage that caused the flow.

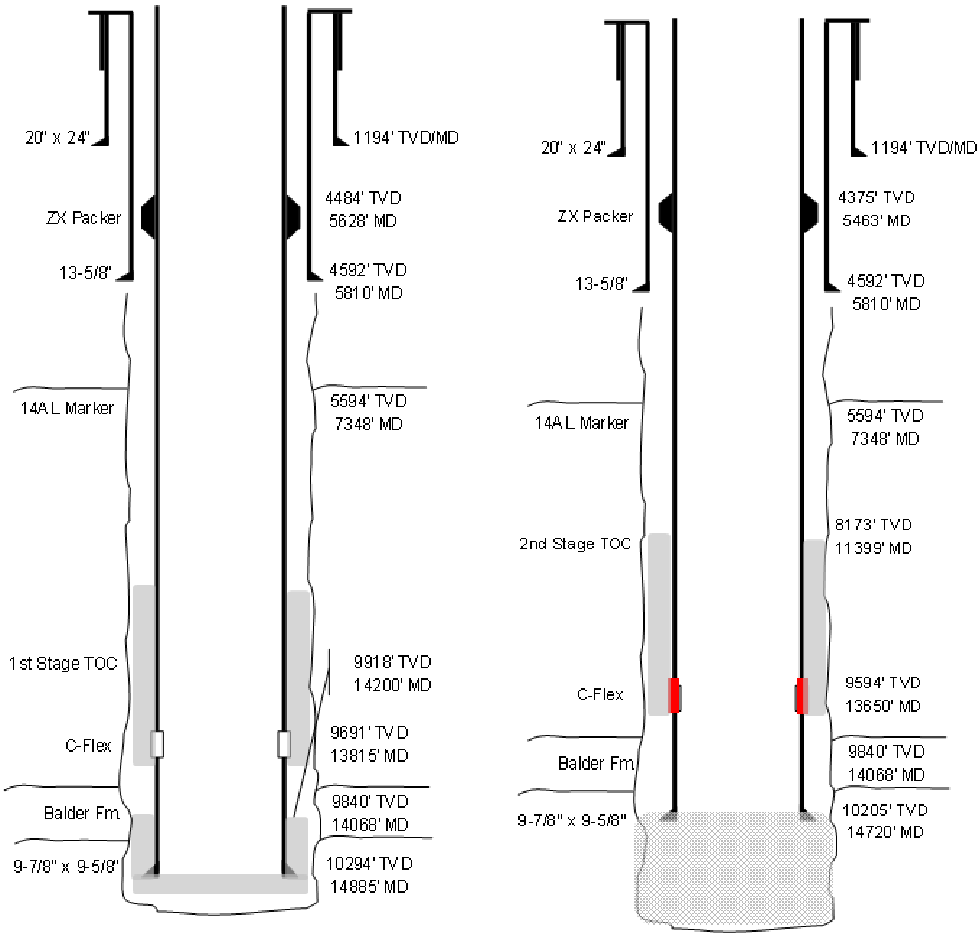


Figure 6-5 Planned (left) and actual (right) cement job on well 2/4-X-16 running a C-flex port collar (Vargas, May 26, 2009)

Figure 6-5 illustrates how the cement job on the Ekofisk field was planned (to the left) and how it turned out due to the contingency plan (to the right).

In general, the cement job on the production casing on X-16 was a success, given the contingency situation. A volume of 150 bbls of cement was pumped into the annulus. The TOC was above both top of Balder and the required 330 ft above the top of the production packer which was planned to be set at 9494 ft TVD. Even though there is a question whether the C-Flex was closed or not, it was a major benefit to run the C-Flex. For the first time, an X-well reached the target of getting the cement 330 ft above the production packer [Karen]. The original plan was to set the reservoir liner hanger above the C-Flex to isolate the area. Due to the contingency operation the C-Flex setting area will now be sealed off by both the contingency liner and the reservoir liner. Due to this are the issues around the unclosed C-Flex not that important. If the C-Flex had not been run, the casing would not have been able to be cemented at all. It would then have required an expensive remedial cementing job, including perforating the casing to perform a squeeze cement job. The worst case would require Plug and Abandonment (P&A) and sidetracking of the well.

An important point learning point is that there were not sufficiently hole cleaning of this well. For future wells the procedure of spotting an LCM pill will be evaluated accordingly depending on well behaviour. The LCM pill in combination with the reamer shoe makes hole cleaning a much more difficult and can lead to stuck pipe. The reamer shoe was not needed in this case since the casing was not rotated. In the future wells that are not going to be rotated a normal guide shoe should be utilized.

6.4.2 FO Collar on Well 2/7-A-13BT2

The FO collars are port collars operated with opening and closing sleeve petitioners, referred to as opening and closing fingers, attached to the drillpipe. The FO collar is also opened and closed opposite to the C-Flex. The FO collars is opened with upwards movement and closed with downwards movement Compared to the C-flex it does not have cups on the operating tool that allows one to pressure up between the cups. The FO collar is then dependent on the BOP. Since there are no cups it can be difficult to know if the cement is injected through the FO collar or if it leaks up inside the casing.

The well 2/7-A-13 BT2 was drilled in the period from August 2008 to January 2009 with injection start January 6, 2009. The well is situated in the north eastern flank of the Eldfisk Alpha structure.

Table 6-2 12" section and 9 7/8" x 9 5/8" casing

Interval	4961 – 10414 ft MD RKB 4809 – 9367 ft TVD RKB
Inclination	13.4° – 68.4°
Azimuth	144.2° – 300.0°
Mud System	14.5 – 14.7 ppg Versatec OBM
Formations	Lower, Miocene, Oligocene, Eocene, Balder, Sele, Lista & Våle

Drilling of 2/7-A-13BT2 was in general a successful operation. On the 12 ¼" section studied in this thesis only medium losses of 13 bbls were reported when running out of hole, with the last section BHA, through the 13 3/8" casing. During casing running no losses was observed. Losses were first observed after the cement head was installed when trying to break circulation. The spacer was pumped with a dynamic loss rate of 50 to 60%. The 50 bbl of 15.9 ppg G-cement slurry and 8 bbl of spacer was displaced with 14.5 ppg mud at 5BPM (215 gpm) / 500 psi. The dynamic loss rate during displacement was 50% throughout the whole job. Prior to bumping the plug the flow rate was reduced to 3 BPM/ 400psi. The plug was bumped with 1000 psi (bumped at 13362 strokes).

After the first stage cement job was finished a second cement stage through the stage collar was going to be done. A FO collar opening/closing tool was run in hole to do the second stage cement job through the FO collar. It was attempted to function test the FO collar before cement job without success. The weight on the opening fingers gave indications of opening the FO collar, but it was impossible to pump through the FO collar. No clear indications of closing the collar were achieved. It can be mentioned that there exists different opinions on whether or not any indication of closing the Collar was achieved. A RTTS was then run hole and it was tried to inject through it without success. The well was then pressured up to 1600 psi without any injection through the collar. All volumes that were pumped came in return.

The injection pressure could not be increased any higher due to concerns of setting the ZX packer, eliminating any other cementing options. If the ZX-packer had set a possibility would have been to do a squeeze job through the FO collar. This is not an ideal solution as it only provides a small amount of cement and it is impossible to know where the cement goes. The pressure needed to cement through the FO collar could also be too high for the operational limit.

Due to the operational issues the only cement in the well was the first stage job. The calculated top of cement outside the 9-7/8” casing was 9583 ft MD when considering a loss zone above the cement. If the loss zone was at the shoe and 50 % of the cement was lost to the formation the calculated top of cement is 9992 ft MD. A BAT-Sonic LWD log was run in the well on a later BHA. An interpretation of this log indicated TOC roughly 10050 ft MD.

Assuming the worst case, which is losses near the shoe, the cement job was not a success. Top of Balder is located at 9715 ft MD and top of cement would then be 277 ft below top of Balder. The cement did not reach top of Balder and is not defined as a success well according to the criteria of COPNO well design philosophy of having the cement at least 330 ft above top of balder.

7 How to Reach the Cement Target

Different suggestions on how to reach the target of having the TOC at top of Balder or 330 ft above the production packer are presented in this chapter. The suggestions originate from discussions with key personnel from different technical disciplines like drilling, cementing, geology and reservoir technology. In addition, solutions to the problem have been sought by performing literature studies.

In the Ekofisk and Eldfisk fields there are five drilling rigs and each well is unique. Due to the complexity of different well configurations and platform restrictions in the Ekofisk and Eldfisk fields, there will not be one solution suitable for all type of wells. Therefore, an approach was made for this thesis that divides the strategies to reach the cement targets, into two categories:

1. No changes in well configuration
2. Minor mechanical changes in well configuration

The first category involves changing rheology of the mud and the cement, and type of cement. In the second category, use of an alternative annulus casing packer and the possibilities of a two-stage cement job were evaluated.

In the end of this chapter different techniques that can improve zonal isolation and the cement job are presented

7.1 Improve Primary Cementing of the Production Casing Without any Changes in Well Configuration

7.1.1 Changing Rheology of the Lead Cement

The current cement procedure on the “old” platforms at the Ekofisk and Eldfisk fields uses two-stage cement slurry, including both lead and tail cement. The lead system is lighter than the tail slurry. One way to improve the primary cementing is to make the lead cement rheology as close to the mud rheology as possible. In this way the lead cement will not give any changes in ECD compared to the mud. The cement “seen” by the well is then only the tail cement.

For efficient hole cleaning, the tail cement should have a higher density and viscosity than the spacer. The spacer should have a higher density and viscosity than the mud. A rule of thumb is to have a difference between the cement/spacer/ mud of 1-2 ppg in density and 15-20 cP in viscosity (Watts, 2009).

The lead cement cannot be foam cement when having cement rheology as close to the mud rheology as possible. The tail slurry, on the other hand, can be foam cement even though the lead cement is conventional class G cement with additives (Watts, 2009).

7.1.2 Foam Cement

Foam cement will reduce the hydrostatic pressure, and thereby the ECD. The M wells have successfully used foam cement on their wells. Foamed cement develops higher dynamic-flow shear stress than conventional cement when pumped, which improves the displacement capabilities. One of the main benefits with the foam cement compared with the conventional G-class cement is its hole cleaning capabilities. Foam is viscous and can be pumped at a lower rate than conventional cement and still give good hole cleaning. This reduces the risk of losses with a foam job. The conventional mud needs to be pumped at a higher rate to avoid contamination during displacement. A Higher displacement rate gives a higher ECD.

The normal cement design of a 10" liner in a M-well is to foam an 18.0 ppg cement slurry to a downhole density of 14.8 ppg. This gives approximately 20 quality foam. The 20 quality foam target is generally considered to be ideal from a mechanical property enhancement perspective. However, due to lost circulation problems in this hole section, the choice of an 18.0 ppg base cement foamed to 14.8 ppg results in several effects which hinder a successful placement of the cement. In fact, several recent drilling reports reviewed indicate total loss of returns as the foamed cement reached the liner shoe. This effect is not unexpected given the choice of cement design and the fluid behaviour of foams." (D. Mueller, 2009b)

As already mentioned, the viscosity of foamed cement is a function of both the base slurry rheology and foam quality. "The 18.0 ppg base slurry, which by itself is relatively viscous, will exhibit an even higher viscosity when foamed. Put in other words, the yield point and plastic viscosity of foamed cement increases above the base cement (unfoamed) yield point and plastic viscosity as the foam quality increases. "If treated as a Power Law fluid, the flow behavior index (n) is lowered and fluid consistency index (K) is increased compared to the base cement values as foam quality increases. " The higher viscosity contributes to a higher ECD value when during displacement, which increasing the likelihood of lost circulation (D. Mueller, 2009a)

The difference in downhole rate of the two foam cement qualities can be determined by equation 5.1.

Downhole rate of currently used foam cement:

Assume pumping the cement at 4 BPM.

$$V_{downhole}=V_{surface}\ (1/\ (1-f))$$

$$V_{downhole} = 4BPM \text{ x } (1/\ (1-0.20) = 4 \text{ x } (1/0.8) = 5 \text{ BPM}$$

On the 10" liner on the Ekofisk M-wells typically 4 BPM surface rates are used, the effective rate of a fluid foamed to 20 quality is 5 BPM. The rate effect combined with the above mentioned viscosity effect can explain why there are reported so many cases of lost return on the M-wells when the foam exits the shoe(D. Mueller, 2009a).

In order to reduce the risk of lost circulation and increase the likelihood of meeting the design objective for covering the entire Miocene section, the following modifications was proposed (D. Mueller, 2009b):

The base cement density should be lowered from 18.0 ppg to 15.8 ppg. This new slurry of 15.8 ppg has an intrinsically lower viscosity than the current 18.0 ppg. The base slurry will then be foamed to the 14.7 ppg. The new foam cement of 14.7 ppg has foam quality of about 9 %.This reduces the foam fluid viscosity and would also lower the effective downhole rate.

The new effective downhole rate is then:

$$Q_{downhole} = 4BPM \times (1/ (1-0.09) = 4 \times (1/0.91) = 4.40 \text{ BPM}$$

The modified foam cement has a lot of benefits. The effective downhole rate will be reduced from 5 BPM to about 4.40 BPM when the foam cement enters the shoe. Since the foam quality is reduced from 20% to 9% the viscosity gain from the foam effect is reduced. All in all this will give a lower ECD.

Modelling was done by Dan Mueller to gether with the cement sevice provider that shows a maximum ECD of 15.05 with WARP mud or a similar low viscosity mud in the hole (D. Mueller, 2009b). The upcoming VA injection wells will circulate in Warp mud prior to cementing of the 10" liner. This will be the first time this is done in a well drilled by COPNO. The well will be drilled with Versatec mud to ensure good lifting/hole cleaning capabilities during the drilling operation.

By replacing the mud viscosity and yield point from Versatec with 50 PV/21 YP to a Warp with 40 PV/9 YP during cementing will greatly improve the opportunity to place the foamed cement above the Miocene formation (D. Mueller, 2009a).

The volume required to cement the entire Miocene formation is much larger than the standard foam jobs that has been done the last couple of years. The volume required to cement the entire Miocene formation is about 350-500 bbls dependent on the depth of the 10" liner and the depth of the last casing shoe. The standard volume on a 10" liner foam job is today 140 bbls. For the upcoming injection well VA-04-H the 10" liner requires 370 bbl to cement the entire Miocene. If the Miocene section was going to be cemented with the standard foam type, which has been used on the M- wells on the Ekofisk field, it would require 150-300 bbls with mixing water. This amount of mixing water is required because of the weight material that is used today to increase the density of the cement base slurry. The weight material needs to be mixed in a pit with the drill water before it is added to the cement blend. The pits on the Jack-up rigs do not have the capacity to make the mixing water needed. The weight material is added to get the base slurry density up to 18.0 ppg .This heavy base slurry is needed to get the 20-25 % foam quality, which is usually used, when the base slurry is foamed down to about 14.5 bbl (Helland, 2009).

Due to limitations to cement the entire Miocene section with the conventional foam slurry a new foam quality as metioned was suggested by D.Mueller as mentioned above (2009) A base slurry density of 15.8-16,2 ppg is here diluted to ±14.7 ppg. This new foam cement does not need weight material. The pit used to mix the weight material and the drill water is then not needed and drill water and chemicals can be transferred direct to the cement unit. By reducing the foam quality to solve logistical issues but still keeping the foam properties (two phase fluid) should make it possible to cement the entire Miocene section with foam cement (Helland, 2009).

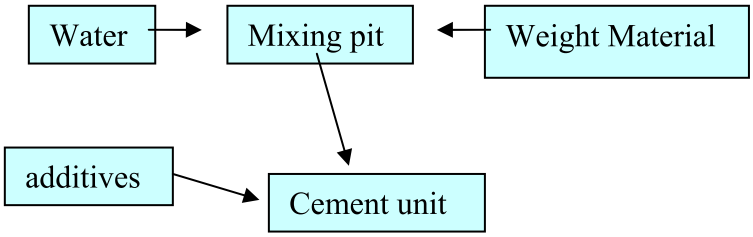


Figure 7-1 Conventional foam cement mixing procedure

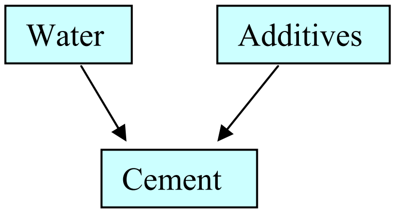


Figure 7-2 Modified foam cement mixing procedure

7.1.3 Light Weight Cement

Light weight cements are used in well cementing to reduce annular hydraulic pressures were weak formations are present or to increase slurry yield to reduce the cost were large annular fills are required (Bjordal, Harris, & Olaussen, 1993). The result from researches on cement sheath stress failures shows that lightweight cement can provide other advantages like resiliency to downhole physical stresses (Goodwin & Crook, 1990). This is a major benefit when it comes to the cement in the Ekofisk field where the stresses in the formation is constantly changing due to drilling, production and subsidence.

Today there exist many different types of light weight cements, like nitrogen foam, hollow pozzolan spheres, borosilicate glass spheres, expanded perlites, blast furnace slags, and ultrafine cements. However, in offshore operations some of these materials can create logistic concerns due to bulk storage and blending requirements (Bjordal et al., 1993; Nelson & Guillot, 2006). Foam cement which has been used as a success on the M-wells drilled with a jack-up rig but most of the "old" rigs in the Ekofisk and Eldfisk fields are too small to have foam cement equipment.

Other light weight additives are sodium silicates and bentonite. Sodium silicates can be handled as liquids and bentonite can be preblended into the mix water. These additives are suited for offshore storage and handling. This in combination with the low cost makes them much used as extenders in the North Sea. However, when it comes to cementing of the production casing set right above the reservoir, silicate and bentonite are not adequate. In this section the temperature is above 230 °F. At this high temperature level the bentonite slurry will not be beneficial due to long term strength instability and the silica slurries become very difficult to retard and properly place. The slurry can harden before placement and once in place gain little compressive strength(Bjordal et al., 1993).

To cement the production casing with light weight cement in a well with rig capability restrictions, the best chance of a good cement job would be to use colloidal silica as a light weight material.

Colloidal silica dispersions are aqueous soils of pure amorphous silica ($SiO2$) and traces of sodium hydroxide ($NaOH$). Like the microsilica used to hinder strength regression of Portland cement above 230°F, colloidal particles are spherical. However, the particle size of colloidal silica is one order of magnitude smaller than microsilica (0.05 microns vs. 0.5 microns). Therefore the surface area of colloidal silica is very large compared to its volume than the microsilica. The surface area of the colloidal silica is about 500 000 m^2/kg. Due to this extended surface area more water can be added to the surface. Increased surface area means that fewer particles are needed. The large surface area makes colloidal silica easy to handle offshore, because of less bulk material needed. The reduced volume compared to microsilica makes overall slurry cost of colloidal silica less. Since the particle are so fine there is virtually no settling of the base material in containment offshore (Bjordal et al., 1993; Nelson & Guillot, 2006).

Light weight cement with a density of 14.6 ppg will be used to try and cement the entire Miocene section in an upcoming Ekofisk K- Well. The lightweight cement is conventional cement that includes colloidal silica. LCM will be added to the cement to reduce lost circulation (D. T. Mueller, 2009). The K-wells are injection wells that have different casing design than this thesis has studied. The production liner set in the Våle formation is a 7 ¾" liner. This liner is hung off in a 10 ¾" intermediate casing. The latest two years the K-platform has shown a good drilling and completion practices. Hydraulic simulations are currently being run by staff in COPNO to look at the chances of cementing the entire Miocene section for this casing design using light weight cement.

This thesis provides simulations investigating the possibilities of cementing the entire Miocene section on both a 9 5/8" x 9 7/8" casing and 9 7/8" x 10" liner with this light weight cement in chapter 8.2.

7.2 Improve Primary Cementing of the Production Casing by Changes in Casing/Well Configurations

7.2.1 Substitution of the Mechanical ZX-packer with an Expandable Packer

The main contributor to a failed cement job of the production casing is lost circulation. The risk of inducing losses during the cement operation is medium to high. Approximately 25% of the wells in the in the Ekofisk and Eldfisk fields are affected by lost circulation during cementing of the production casing set above the Ekofisk formation. Loss of circulation can lead to cemented intervals of less than 20 m rather than the 100m as specified by NORSOK D- 010 guidelines. COPNO has documented a deviation against these guidelines. Due to this deviation there are two compensating measurements (Bashford, 2008):

i. Annulus pack-off element shall be installed at the previous casing shoe.
ii. During abandonment cement squeeze plug must be set in the annulus to provide an additional permanent seal.

One condition that is worsening lost circulation is the presence of an annulus pack off element, the ZX-packer. On the 2/4-X wells in the Ekofisk field a 9 5/8" or 9 7/8" production casing is run inside a 13 3/8” or 13 5/8” casing, and the current completion uses a mechanical ZX-packer and anchor to seal the annulus to prevent gas migrating from the 13 3/8” casing shoe. This packer is normally set in the casing string at around 1300 ft to 5000 ft TVD and its function is to seal the casing / casing annulus above. The setting depth of the packer should be deep enough that the formation strength at its setting depth is sufficient to contain any possible migrated gas pressure from the Miocene (Bashford, 2008).

The issues with the ZX-packer are that it has an OD that is much larger than the production casing itself. This enlarged OD makes an annular restriction which imposes an ECD constraint in the already narrow operation window. The history also shows that its sealing quality deteriorate over time. Use of a restricted OD packer should therefore help alleviate this issue in the future (Rodger, 2009).

Formerly inflatable ECP`s were used, but due to problems with failure of these packers the current design practice is to use a Baker ZX-packer. The ZX packer is close to a metal to metal seal and hence more reliable over the lifetime of the well (Bashford, 2008).

“The ECD caused by the ZX-packer can be reduced and cement placement improved by: 1) reverse cementing, or 2) use of a Read External Casing Packer which has a smaller OD than the ZX packer, or 3) a combination of 1) and 2), or 4) cement the entire Miocene section” (Watts, 2009)

As part of the preparation for wells drilled at the 2/4-K platform, READ was commissioned to design and test an expandable packer that would seal between 9-7/8" and the 11-3/4" casing. There was at that time no ZX-packer that could fit the 11 3/4”X 9 5/8” annulus. The new packer set deeper will eliminate the ZX packer that is currently set in the 13-3/8" casing around 1300 ft TVD. With this expandable placed near the 11-3/4" shoe, the sealing point to stop gas migration is in the optimum location. This will prevent high pressure gas and crude from building up under the shallow packer which is creating a serious problem when the well is plugged and abandoned. Further, with a deep set seal the well is much easier to recover for slot recovery and further use (Watts, 2009). The expandable packer from READ was tested to gas bubble tight packer standard, ISO 14310 V0 (Rodger, 2009).

For full strings of 9-5/8" casing run in wells where the sidetrack is deep out of the 13-3/8"a similar packer to the one mentioned have recently been proposed to COPNO by READ. The proposal covers in detail design, manufacture and verification testing of a HETS (Hydraulically Expandable Tubular System) Casing Packer to be run with 9 5/8” or 9 7/8” casing and set inside 13 3/8” casing. The same packer can most probably be used in 13 3/8” or 14” casing.

The advantage is a larger clearance and lower ECD. Unlike a ZX-packer that has an OD very close to the ID of the 13-3/8" READ expandable, would have almost the same OD as the 9-5/8 “ casing and would expand after the cement job, creating a gas tight seal between the 13-3/8” by 9-5/8"casing strings.

The READ (HETS) Casing Packer has a substantially smaller diameter removing any concerns over ECD when cementing the production casing, and it is very robust allowing the casing to be rotated and manipulated without any concerns about causing damage to the casing packer sealing quality. The READ expendables are very simple to mill through and have no moving parts that complicate removal. It can be expanded at any time after the casing has been cemented and provides a combination of a V0 (gas-tight) seal and significant bi-directional load bearing capability (Rodger, 2009).

"The tools and auxiliary equipment required for expanding the casing packers have already been developed and are based in Aberdeen available for field operations" (Rodger, 2009)
The same expansion tool as developed for the 11-3/4" by 9-7/8" can be used for the 13-3/8" by 9-5/8". The only development left is the engineering of the packer itself, which is a straightforward exercise. A test would then be performed to verify the design.

Table 7-1 READ expandable packer dimensions and load properties (Rodger, 2009)

Drift ID	8,50"
Maximum OD	11,0"
Maximum ID to be set in	12,60"
Minimum axial bearing	250 000 lb (tension or compression)
Maximum differential pressure	2500 psi (ISO 14310 VO) gas

<u>Setting depth of a casing annulus packer</u>
Today there is observed a high amount of gas below the ZX-packer which is set at about 1300 ft TVD. P&A of these wells can be almost impossible. The mud weight needed to kill the well in a plug and abandonment situation can be calculated. Considering that the weakest point is below the previous casing shoe (often 13 3/8") any pressure above the fracture pressure gradient here is assumed to leak into the formation. If a gas bubble leaks up from the Miocene section it will most likely fracture the formation below the 13 3/8 casing shoe. The highest pressure that can be seen above the 13 3/8" packer is then 16.0 ppg. The LOT is assumed to be the fracture gradient. The pressure found below the ZX-packer can than not be bigger than the pressure at the 13 3/8" shoe. The fracture pressure at the 13 3/8" shoe at 4500 TVD is now "seen" at 1300 ft TVD.

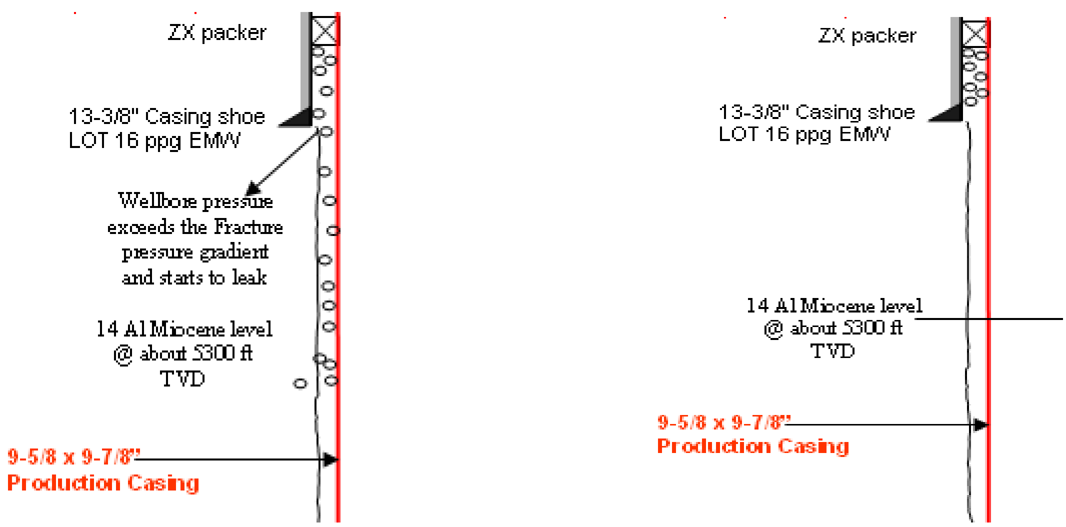


Figure 7-3 Gas from the Miocene level trapped below the ZX-packer

The maximum pressure at the 13 3/8” casing shoe would in this case be:

$P_{at\ 4500\ ft\ TVD}$ =16 x 4500 psi x 0.052= 3744 psi

Assuming that the gas gradient is 0.1 psi/ft, the pressure below the ZX-packer would then be:

$P_{at\ 1300\ ft\ TVD}$ = 3744- (0.1 psi/ ft x (4500-1300)) = 3424 psi

The mud weight needed to kill this well is then:

m.w = P (psi) / (0,052 x ft TVD)
m.w = 3424 / (0,052 x 1300) = <u>50.6 ppg</u>

The mud weight needed to kill the well in these simplified hydrostatic pressure calculations would be as high as 50.6 ppg. Today there exist no muds heavy enough to make a hydrostatic column that would kill this well. The pressure is too high on a low depth. This way of completing a well is not recommended. If a compensating annulus casing packer should be set in the well its setting depth should definitely be deeper than 1300 ft. If the ZX-packer is set at 1300 ft and gas is noticed below the packer, these wells would be very difficult to plug and abandon. One way of doing it is to fill up the annulus with Zinc bromide brine that has a density of 20 ppg and then perforate the casing and allow the well to kick into the wellbore to bleed of the pressure. This can be extremely dangerous and. There are also HSE issues when it comes to the Zinc bromide mud and it is not recommended to be used if not necessary.

7.2.2 Two-Stage Cementing

There are three concerns about a stage collars in general:

1. Problems closing
2. Mechanically weak
3. Potential leak path

The first and overall highest risk of running a stage collar is the risk of not being able to close it. The history of running stage collars shows that that the most common causes of failure is the inability to close the tool after the cement job. On the Ekofisk field, two-stage collars have been run and both had problems closing. The first time the collar did not close because a larger amount of cement than planned was pumped during the first stage of the cement job.This volume was too big and cement was found outside the stage tool. The second time a port collar was run on 2/4-X-16, see section 6.4.1. The risk of running a stage collar in a well if it is not closed is high. The whole integrity of the pipe will then be lost. A possible solution will be to set a casing patch to cover the unclosed collar. If the cement in the collar is strong enough the casing patch can be set after the last section of the well is drilled. In this way the last section can be drilled with the same dimension as planned. If the casing patch is set before this section is drilled there may be a restriction in hole size for the next casing size. A solution to avoid the problems connected to the inability to lock the collar is to install the collar below the liner top hanger of the reservoir liner. The liner will then seal of the collar and it do not matter if the collar was not fully closed. This was done on X-16.

The second risk associated with running a stage collar is that there is more mechanical parts downhole that can fail. When it comes to bending stresses the stage collar can be weaker than the casing and connections. The primary cause of casing failure is bending loads due to subsidence. A weaker element in the well could therefore reduce the lifetime of the wells. There are today many types of both stage collars and port collars on the market and the mechanical properties of them vary. The port collar from Peak Well Solutions, named C-Flex, has the same mechanical properties as the casing and connections. Due to this it has a major benefit leaving out the mechanical uncertainties connected with running a stage collar.

The third risk of using a stage collar is that it is a potential leak source. The seals can be damaged when the casing is run in hole and the collar can start to leak when the well is drilled out.

Stage collar run on a liner (M-design)

Running stage collars on a liner is much more complicated than running stage collars on a casing. Cementing a liner includes dropping balls, and a stage collar that uses balls to operate the collar would make the whole job and equipment way to complicated. Another option would be to run a port collar that is operated by a sleeve like the C-flex by Peak. The restriction here is the expandable liner hangers. When expandable liner hangers are used the liner is run on the drill pipe. During the primary cement job the drill pipe holds the liner in place. It is therefore impossible to get down with a shifting tool to operate the collar. After the primary job the liner hanger is expanded and the packing element set. It is then impossible to go down and perform a proper second stage job since there is no circulation option through the liner hanger. The second stage job cement would then only be squeezed into the formation. The only possibility to do a two stage job with an expandable liner would be to run two stage collars. One would be used as normal to pump cement through and one would be placed higher up to take the return through. The question if the risk of not being able to close the port, is lower or higher than the gain from doing a two-stage job. Another option to cement a liner in two stages is to use a mechanical liner hanger. The downside of having a mechanical liner hanger is that it cannot be rotated. The benefit is that it can have stage collars. The mechanical liner is hung off by seals during the primary cement job. It is therefore possible to go down with an operating sleeve to open a port collar to do a second stage job. The packer element is set after the primary job.

If the hole section have high inclination or severe doglegs it would be most beneficial to run a Versaflex liner hanger and rotate the liner rather than running a mechanical liner hanger and do a two-stage job. This is due to the benefits of removing any immobile mud especially on the low side, where solid beds tend to appear. If there is a low inclination, the gain in ECD by having a ZX-packer and doing the job in two stages can be higher than being able to rotate the casing. This applies specifically on those wells where losses are anticipated due to losses during drilling and casing running that are not healed before cementing.

Stage collar run on a casing (Ekofisk X-ray and Eldfisk Alpha design)

Before running stage tools in the wells a proper risk analysis should be performed to highlight the risk of not closing the collar against the need for it to achieve the cement target. Some argue that the stage tool will always represent a “hole” in the casing, because there may always be a question mark over its sealing capabilities. If the risk of running it is found too high, a solution might be to run below the planned reservoir liner hanging depth as a contingency solution available. The reservoir liner will then seal it off and the risk of not being able to close it is lowered. The cost of running a stage collar as a contingency without using it, is much lower than not being able to cement the well at all. If the well cannot be cemented the worst case will be to plug back and sidetrack. A perforation squeeze through the tubing could also be done, but this will not have the TOC as according to COPNO requirement.

If losses to the reservoir occur during a normal cement operation, almost all the cement from the first stage will go into the reservoir due to the combination of the narrow operational window and natural fractures. A two-stage job with an expandable packer may be a possible solution to achieve a better cement job if such losses are expected. After the first job is performed the expandable packer can be set and a stage tool above the packer is opened and the second stage job can be performed.

The expandable packer can also be set above another weak zone where losses are expected. In the overburden that the production casing at the Ekofisk and Eldfisk field penetrates there are a lot of potential loss zones. It is therefore very difficult to predict where the losses will be taken. An annular casing packer might therefore not be the best solution to getting the cement to right level in the annulus.

7.2.3 Reverse Circulation

COPNO are now investigating if it could be possible to do a reverse circulation job by using a crossover tool, like the ones used in gravel packing. The main benefit of reverse circulation is that it is possible to cement the entire Miocene section. The restriction in the liner hanger cannot be seen by the rest of the well. The gravity works with you and not against you. One of the concerns of doing the reverse circulation is that it is difficult to exactly predict the volume to pump. The hole might be washed out, and this might not be taken into account. The volume that is pumped may then be too low and not able to fully cement the shoe. However, if the volume is too big there might be too much cement in the casing that will take a long time to drill out. It is also very critical to get a good cement job at the shoe. This is more difficult to achieve with reverse circulation. The float shoe in the casing shoe must also be removed and replaced if a reverse circulation job is to be preformed (Watts, 2009).

7.3 Complementary Actions to Improve the Cement Performance

There exist a lot of complementary actions that can help improve the cement job and zonal isolation in a well. This will chapter will briefly explain two of them, Casing drilling and swell packers. Casing drilling help reduce loses by increasing the fracture gradient of the formation and the swell packer can be used as a redundancy above Miocene layer if the cement is not covering this section. In addition to these two methods some solutions is not covered by this thesis can be for example expandable casings or Managed pressure drilling, MPD. Expandable liners can be a solution that can reduce losses near top of the reservoir. The 9 5/8" casing could then be set 400 ft above the reservoir were the regression in the fracture gradient curve starts. An expandable liner could then be run to cover the last feets above the reservoir. This would allow drilling of the reservoir and complete the well with little or no reduction in ID. This solution would depend on the collapse pressure of the expandable liner. The reduced collapse pressure of expandable liners may be a restriction since the overburden stresses may produce a too high load on the liner. MPD is another method that can reduce the risk of lost circulation during drilling and cementing by drilling at balance (keeping the wellbore pressure close to the pore pressure). This makes it easier to keep the ECD below the fracture pressure. The possibilities of using MPD on the Ekofisk field and Eldfisk field on the future projects should be investigated more.

7.3.1 Casing Drilling

Casing drilling can help overcome the difficulties with the operational drilling window within the final few hundred feet of the section TD. Casing drilling has the so called smear effect that will heal losses and give a better chance of achieving a better cement job. Observations show that casing drilling improves the strength of the rock. The theory behind this is not fully understood but it is believed that the casing drilling improves the rock strength because the pipe rotates against the formation and creates small fractures in the rock that is filled with mud. These small faults are believed to change the hoop stress in the formation and thereby changing the fracture gradient. In the start it was believed that the smear effect came from a plastering layer of mud around the borehole. This was proven wrong when side wall cores were taken in a casing drilled well. These cores showed no layer of mud (Watts, 2009).

Casing drilling gives a more gauge hole which means that the top of cement is more likely to be as predicted. In addition, casing drilling provides a more efficient mud displacement since the pipe can be rotated during cementing.

Casing drilling is limited by geometry and diameter of the tool. Only half of the wells drilled by COPNO in the Greater Ekofisk Area are with today's technology able to be drilled with casing drilling. Today, more and more extended reach wells and complicated wells are drilled. At the Ekofisk field drilling a new a well is also complicated since there are so may well paths there already that needs to be avoided. The well trajectory may therefore be too difficult to be drilled with full casing drilling.

The wells in the new upcoming Eldfisk II project will be extended reach wells and cannot be casing drilled. The other upcoming project on Ekofisk called Zulu will have crestal wells and the risk will be too high for casing drilling. When it comes to the M wells, about one third of the wells were able to rotate the liner and could be casing drilled. It is much easier to drill a 7 3/4" casing with casing drilling. It is fairly easy to switch back and forth between casing drilling and conventional drilling. This makes it possible to drill some of the sections in a well with casing drilling. This is done today on the wells on the K-platform on the Ekofisk field. Wells drilled from this platform are sidetracks into highly differentially pressurized water zones. Casing drilling gives coverage of these high pressure zones with the primary cement job before reducing the mud weight into the top of the reservoir. On the K-platform, they are "casing drilling light". This means that they do not have a BHA in front of the casing to steer with.

One solution to overcome the losses near to top of the reservoir can be to drill only the last part of the section right above the reservoir with casing drilling to strengthen the formation at this depth. The concern is that no logs can be run to pick the Våle formation and the right casing setting depth. Today, the Våle formation is picked by a combination of biostratigraphy data, cuttings, and logs. It would be possible to determine the depth of the Våle formation based on core samples and microorganisms only but the prediction would then not be as exact.

7.3.2 Swellable Packers

A swellable packer is a standard oilfield tubular with a rubber chemically element bonded along the length. In exposure to hydrocarbons the rubber element swells to form an annular seal through an absorption process known as thermodynamic absorption.

"Thermodynamic absorption involves the affinity between hydrocarbon molecules and rubber molecules due to similar thermodynamic properties. The absorption causes the rubber molecules to stretch resulting in an increase in volume (swelling) "

The mechanical properties of the swellable packers are a function of the volume changes of the element. The higher the swelling percentage, the less internal pressure the swellable packer is able to build up. The hydrocarbons will not degrade the rubber but alter the mechanical properties, reducing the hardness and the Young's modulus.

One benefit with the swellable packer is that it will seal even in an irregular hole. The concerns are that it then might swell more and lose some of its mechanical properties. It is important to carefully choose a setting depth were the formation is not washed out to ensure that the swellable packer is sized correctly to fill the annular space between and sustain the required differential pressure.

The length and OD of the swell packer is adjusted to fit the required differential pressure across the packer. The maximum length of the element is approximately 33 ft (10 m). This is because a joint is approximately 40 ft (12 m) and the need for handling/tong space to make up the connection and run in hole.

The key variables that determines the time required for the packer to swell is viscosity and temperature. If a swellable packer is to be run in OBM, which is the most common practice in the North Sea, a multilayered design can be used that hinder swelling when run in hole. One example of a multilayered design is shown in Figure 7-4.This is an illustration of Easywells Swellpacker. The design consists of a high-swelling inner core surrounded by a low swelling outer layer and a diffusion barrier (Easywell, 2009).

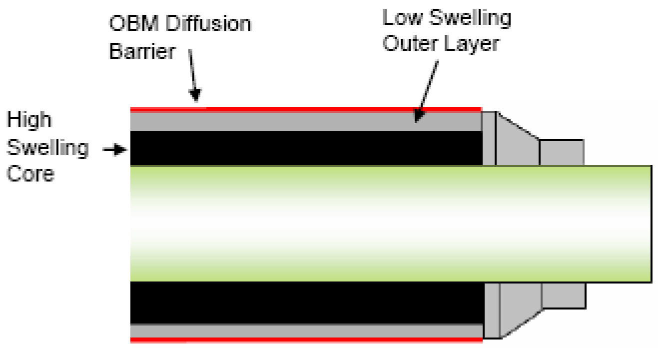


Figure 7-4 (Easywell, 2009)

A swellable packer can be used in several different situations. When it comes to cementing, a swellable packer can be set either above the top of cement as a redundancy to stop gas migration through the cement, or as a cement assurance when put around the pipe inside the cement to stop gas from migrating up any microannuli near the casing. The type of swellable packers studied in this thesis is the one set above the top of cement and the Miocene layer to stop gas from migrating. The packer will then act as an isolation barrier element that can back up the cement where cement losses has been observed. This can help improve the long term well integrity.

The setting depth of the swellable packer is another topic that must be carefully evaluated. The placement must not be too high. The first 400-500 ft below the previous shoe is often very washed out. The diameter here is therefore difficult to predict. The uncertainties of running a swellable packer in this area are too high and it is therefore recommended to set the swellable packer lower in the well. A gas bubble that is rising may have a high enough pressure to fracture the formation at the 13 3/8" shoe. The swellable packer should be set immediately above the source.

The length and OD of the swellable packer is adjusted to fit the required differential pressure across the packer. As mentioned previously, the maximum length of the element is approximately 33 ft (10 m). The swellable packer will decrease the flow-by area in the annulus and consequently increase the ECD. It is the pressure that the packer should be able to withstand that determines the OD of the packer. In the Ekofisk and Eldfisk fields there are already problems with losses when running the casing in hole. The surge pressure when running the casing with a swellable packer will increase and the chance of losses will increase. During circulation and cementing of the well, the swellable packer will act as a restriction to the flow and increase the ECD. The ECD when cementing the production casing in the Ekofisk and Eldfisk fields has already a very small operation window. An increase in the ECD is therefore very critical and will decrease the chance of getting the cement to top of balder or 330 ft above the production packer. The differential pressure across the packer must therefore be carefully modelled.

COPNO has today not run any swellable packers in their wells. A research was therefore done to look at the possibilities of running a swellable packer as a redundancy above the Miocene layer to prevent gas accumulation below the ZX-packer, when planning to have the TOC 330 ft above the production packer. The results from this research are described in detail in section 8.1.

8 ECD Simulations

8.1 Swell Packer Simulations

The design and application of the swellable packers are based on four main variables; the open hole size, the mother pipe size, required minimum differential pressure across the packer, and the time to seal. To find an optimum Swell Packer size, simulations in Swellsim were done together with Easywell. Swellsim is a simulator that can predict the expansion ratio (rubber thickness vs. open hole size), differential pressure capability (percent swelling and element length) and the time to seal (packer OD and packer design vs. hole size and fluid viscosity and temperature)

The pressure differential ΔP, needed across the packer set above the Miocene level was calculated to be 3000 psi. Simulations in Swellsim® were provided by Easywell to calculate the dimensions of the Swell Packer, based on the given ΔP. The length of the packer was set to 10 ft. The Swell Packer OD needed to withstand the differential pressure was 11.15 in. Results from the Swellsim® simulations can be found in appendix B.

To investigate if a swellable packer can be run as a redundancy solution above the Miocene formation without creating a too high ECD that can contribute to losses, hydraulic simulations were performed.

A modelling program, Virtual Hydraulics developed by MI Swaco, was utilized to conduct the hydraulic simulations. The output from the program shows the difference in ECD, which is the most interesting parameter. Simulations were done on an Ekofisk X-ray well namely 2/4-X-16. The planned well configuration as explained and illustrated in Figure 6-5 in section 6.4.1 was used. The swellable packer was set at 6901 ft TVD in the simulations. The snap shots with the results from the simulations can be seen in appendix C. The ECD at the 13 3/8” shoe and at the 9 5/8 “casing shoe from the simulations are presented in the table below

Table 8-1 ECD simulations with swell packer

	MUD System	
	Warp	Versatec
No packer	13 38” csg shoe, ECD = 15.03 ppg 9 5/8” csg shoe, ECD = 15.06 ppg	13 38” csg shoe, ECD = 15.40 ppg 9 5/8” csg shoe, ECD = 15.41 ppg
Swell Packer	13 38” csg shoe, ECD = 15.03 ppg 9 5/8” csg shoe, ECD = 15.06 ppg	13 38” csg shoe, ECD = 15.40 ppg 9 5/8” csg shoe, ECD = 15.41 ppg

It can clearly be seen from the simulations that the swellable packer with the dimensions simulated has no effect on the ECD. As such, it can be run without the concern that it will contribute to a high ECD. Further research should be done to investigate the possibilities of running a swellable packer when not planning to cement the entire Miocene section.

The Warp system gives an overall lower ECD due to its low rheology. The Warp system utilized micron sized particles as weight material which makes it a thin mud system compared to the Versatec mud system that uses the API barite.

8.2 Well 2/4 X-04B ECD Scenarios: Cementing the Entire Miocene Section with Light Weight Cements

The future aim of COPNO is to be able to cement back to the previous casing shoe and cover the entire Miocene gas zone. Cementing the entire Miocene formation has until today not been prioritised and tried out, due to the difficulties connected to the formations, well design and cement program. In this thesis simulations have been run to check the possibility of achieving this future aim. The well 2/4-X-04B was chosen to look at different casing designs, casing packers and mud systems. The well was drilled in 2006 and is located as an upper Ekofisk (EA) horizontal producer on the western flank of the Ekofisk field. The well path and casing setting depth from this well was chosen, but in order to evaluate the possibilities of cementing the entire Miocene section, the mud and cement program originally used in this well was not taken into account. The currently used cement slurry is too heavy for cementing the entire Miocene section. In this study a, new light weight slurry was used. This cement slurry composition has never before been used in COPNO. There is currently being run simulations to look at the possibilities of cementing the entire Miocene section on a 10 ¾” x 7 ¾” casing design (K-well) with this slurry (D. T. Mueller, 2009). This thesis has looked at the possibilities of using this new light weight cement slurry to cement the entire Miocene section on the casing design most used on the Ekofisk X, Eldfisk A, and Ekofisk M Rigs. This includes looking at both 13 3/8” casing x 9 7/8” casing design and the 13 3/8” casing x 9 7/8” liner design. This will reveal the differences between a full casing string and a liner. Two different casing packers and two different liner hangers were evaluated. The interesting output is the ECD values in the different scenarios. 19 different cases were studied and the ECD scenarios for the different cases are presented below.

Both the Warp mud system and the Versatec mud system were evaluated. Versatec mud is the mud used on most of COPNO wells today. This is compared to the low rheology mud system WARP to see the difference in ECD.

The CemFacts software was used to run the simulations. This is a cementing modelling program by BJ Services. Simulations where performed together with COPNO cementing specialist.

To make the model, different input data had to be prepared and incorporated into CemFacts. The input data was gathered from COPNO internal drilling and well data base, *The MaxWell* structure. The input data used to build the simulation cases are:

- Well trajectory (measured depth, inclination, azimuth)
- Well configuration (casing sizes, connections, hole sizes)
- Rheological Data (Fann Rheometer data given by mud and cement service companies)

Modelling Assumptions:

Average hole size: 12 ¾-in

The hole is drilled with a 12 ¼” bit size and assumed to be washed out to 12 ¾” hole. It should be kept in mind when looking at the different cases that if the hole is not washed out the ECD will be higher due to lower annular clearances.

Centralizer standoff: 60%

Centralizer standoff was set to 60 %. 100% standoff will give the worst ECD calculation because there is not a “wide” side for preferential flow to occur. Simulations in different softwares will, due to this, give the highest ECD if the casing is fully centralized. If the standoff is too high it is difficult to shear the mud on the narrow side. In the simulations it was decided to simulate at a more predicted realistic standoff. The standoff was therefore set to 60 % (Dan Mueller) However, centralization is important to ensure a good cement bond around the whole casing and the aim is at least 80% standoff.

The casing dimensions used in the simulations is listed below:

13 3/8 “casing shoe setting depth: 4895 ft MD/ 4767 ft TVD.
Nominal ID = 12.375”.

Production casing dimensions:

OD = 9 5/8” x 9 7/8”
9 5/8” ID = 8.535 , 9 7/8” ID = 8.625
Crossover at 8583 ft MD
Couplings 9 7/8”: OD= 10.984, ID = 8.625 (same as casing)
Coupling 9 5/8”: OD= 10.625, ID = 8.535 (same as casing)

The couplings are taken into account in the simulations. An average of 12 inch coupling length where assumed. They are represented in two points on the casing string, one above the 13 3/8” casing shoe at 3100 ft MD and one in the open hole at 10000 ft. The couplings represented at 10000 ft are 210 ft long and the couplings represented at 3100 ft are 70 ft long.

The connections between the different casing joints have an enlarged OD compared with the casing. The OD of the casing joints are 10.125 ft. In the simulations all the connections was included at two different depths on the casing string. The jump in ECD seen at around 3000 ft in the simulations is only due to the connections. This increase in the ECD will be seen for all the cases with the production casing.

Baker ZX-packer dimension simulated:

6 ft PBR OD = 10.63 “
9 ft Max OD = 12 “
9 ft hanger = 9.7”

HETS-READ Expandable casing packer simulated:

Length: 10.75 ft
OD: 11 ft.
ID: same as casing

Production liner dimensions:

9 7/8” OD
8.625” ID
Crossovers 51/2” DP, 4.778” ID at 4695 ft MD

Liner hanger dimensions:

Expandable liner hanger (Versaflex)
10 ft PBR OD = 12.142"
10 ft hanger element OD = 12 185"
ID = 10.65"

Mechanical liner hanger (Baker)

	Depth:	OD:
5 1/2-in DP	4695 ft	5.5"
Baker ZX	4701 ft	10.63"
Baker ZX	4710.32 ft	12"
Baker ZX	4720 ft	9.7"
Baker ZX	4728 ft	11.5"

Rheology models:

A comparison of the different rheology models was done to find the best fitted model. The Fann data for the mud, spacer and cement was used as input in CemFacts and the model that gave the best fit to the data was chosen. For both mud types (Versatec and Warp) the Herschel-Bulkley model definitely gave the best correlation. The correlation factor can be seen in appendix D in Figure D-0-2 and Figure D-0-3. For the spacer, the Bingham Plastic model gave the best correlation with the Fann data. This is the model used when designing cement jobs by the spacer and cement service providers. For the cement, the power law had the overall lowest correlation factor, but when looking at the graph it can be seen that the Herschel Bulkley model gives the best fit in the shear range that will be found during the cement placement. Therefore, the Herschel Bulkley model was chosen for the cement. This is illustrated by Figure 8-1, Figure 8-2, and Figure 8-3 below. The models also high lights the typical weaknesses of the Bingham plastic model and the power law model when it comes to describing cement slurries. The Bingham model have a tendency to overestimate shear stresses at low shear rates, while the power law model can give significant errors across the entire shear-rate range. The power law model normally underestimates the shear stresses at both ends of the shear-rate spectrum and overestimates them at intermediate values.

Cement Rheological Correlations

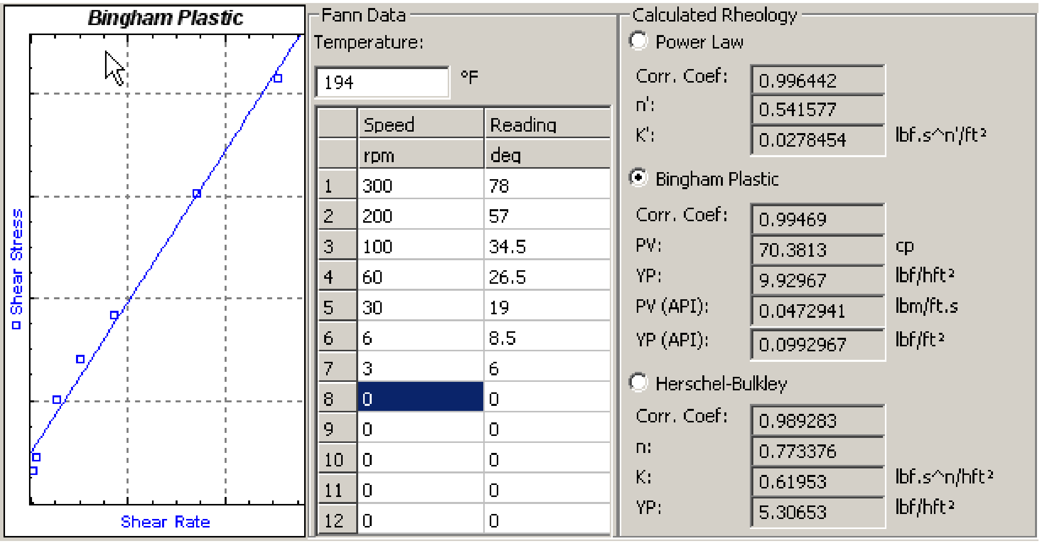


Figure 8-1 Bingham Plastic Model

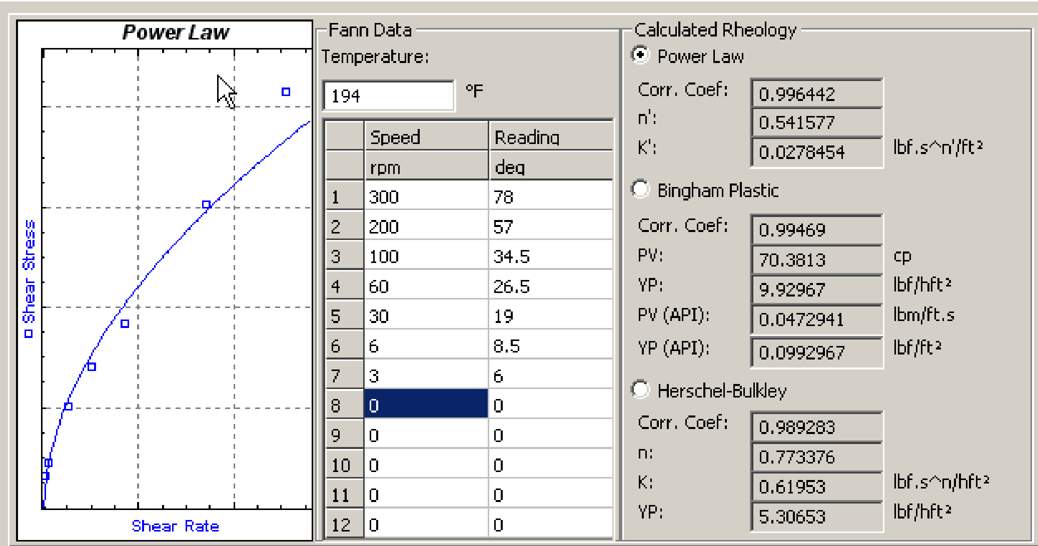


Figure 8-2 Power Law Model

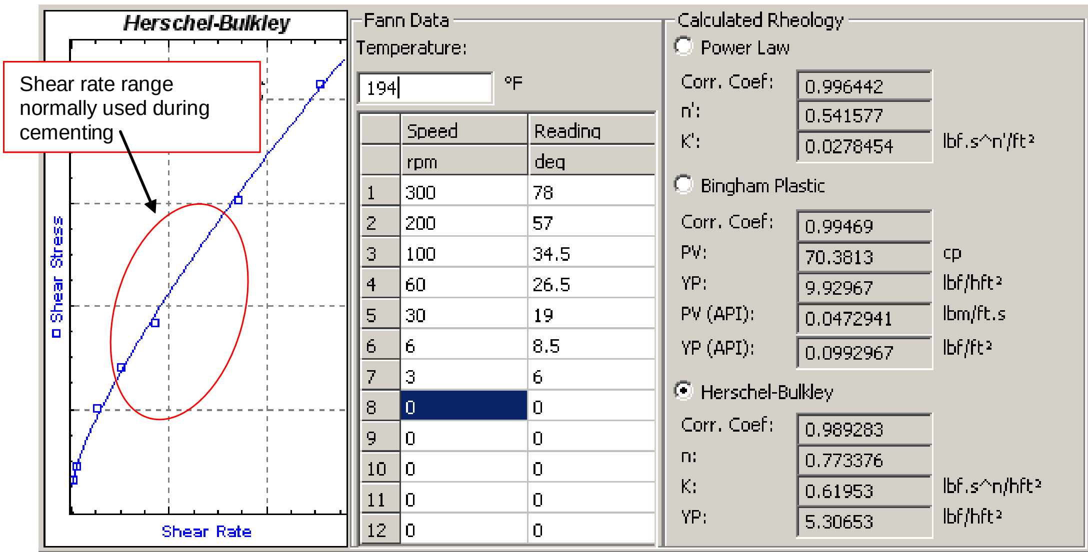


Figure 8-3 Herschel Bulkley Model

Warp OBM: (Herschel Bulkley Model)
Density: 14.6 ppg
n': 0.842629
K': 0.281017
YP: 3.39 lbf/100ft^2
SGS: 9 lbf/100ft^2
Coefficient of Correlation: 0.999336

Versatec OBM: (Herschel Bulkley Model)
Density: 14.6 ppg
n': 0.847588
K': 0.447461
YP: 11.1097 lbf/100 ft^2
SGS: 25 lbf/100ft^2
Coefficient of Correlation: 0.999663

Spacer: (Bingham Plastic parameters assumed)
Density:14.6 ppg
PV: 70 cP
YP: 10 lbf/100 ft^2
Volume: 100 bbls

Cement: (Top at 4895 ft MD/4767 ft TVD) (Herschel Bulkley Model)
Density : 14.6 ppg
n': 0.773376
K': 0.61953
YP: 5.30653 lbf/100 ft^2
Coefficient of Correlation: 0.989283

Cement volume: 483 bbls for full casing string scenarios, 465 bbls for liner scenarios

Displacement fluid in all simulations: OBM at 14.5 ppg

For liner scenarios, TOL at 4695 ft MD, VersaFlex liner hanger + PBR, or Baker ZXP liner hanger + PBR

8.2.1 Results and Discussion

The pore pressure gradient is not included in any of the graphs in this evaluation. The pore pressure was in these simulations set equal to 13.8 ppg at the previous casing shoe and 12.5 ppg at the production casing setting depth. The pore pressure gradient is in the simulations defined to be below 14 ppg for all cases and not visible in the figures. The pore pressure values chosen in these simulations are relatively small and are expected to be higher on the Ekofisk and Eldfisk fields. The current operational window on the Ekofisk and Eldfisk fields can be seen in Figure 2-21 and Figure 2-18. A mud weight below 14.5 ppg is not recommended for drilling the section studied in the Ekofisk and Eldfisk fields. In these simulations the interesting output is the ECD compared with the fracture gradient.

The well has the last casing set at 4895 ft measured depth. The fracture pressure below the casing shoe is assumed to be equal to the LOT. The LOT was determined to be 16.2 ppg at this depth. It should be kept in mind that for other wells this value may be different. A fracture gradient is generated below the last casing shoe (magenta line). The fracture gradient at the production casing setting depth was set equal to 15.4 ppg in the simulations. The line between the fracture gradients then represents the fracture gradient curve in the simulations. This value is a reasonable assumption. However, note that these are just predicted values and that the fracture gradient may vary a lot, especially right above the reservoir. The density of the mud (blue line in the graphs) is set to 14.6 ppg in all of the cases. In addition to evaluate the ECD against the operational window, circulating pressure and the ECD at shoe is plotted against time for each case.

The results from the cases are presented in chapters 8.2.1.1 and chapter 8.2.1.2. The graphs are diagrams from the simulations will be referred to in the text and can be found in Appendix D. Graphs from two of the cases will be introduced and described below to explain the different parameters.

8.2.1.1 Casing 9 5/8 x 9 7/8”

<u>Mud Circulation</u>
CASE 1:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD)
Warp OBM only circulating at 6 BPM.

The effect of circulating with Warp OBM in the well was tested. Figure 8-4 and Figure 8-5 illustrate the results when Warp OBM is circulated at 6 BPM. In Figure 8-4 the measured depth is shown on the Y axis with values in ft and the density (gradient) is shown on the X axis with values in ppg. The first figure can tell if the ECD in the well will exceed the fracture gradient. The magenta line is the fracture gradient curve, the blue line represents the mud in the well and the green line is the ECD. The small “jump” in the ECD at about 3000 ft MD seen in Figure 8-4 is caused by the connections between the casing joints. For CASE 1 the ECD stays below the fracture gradient in the entire well. Figure 8-5 illustrates the circulating pressure (black line) and the ECD (Blue line) at the production casing shoe plotted against time. In CASE 1 the ECD at the shoe is simulated to be 15.08 ppg and the circulated pressure calculated to be 463 psi.

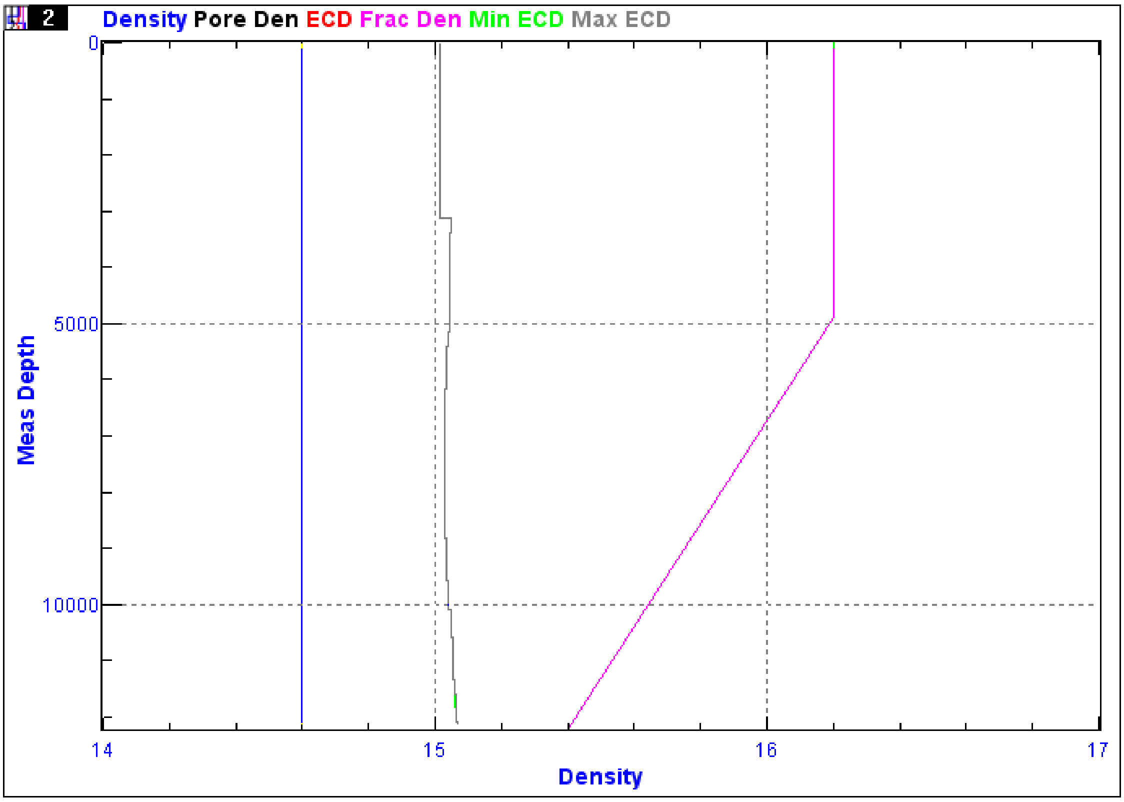


Figure 8-4 ECD compared with the fracture gradient for Warp circulating at 6 BPM

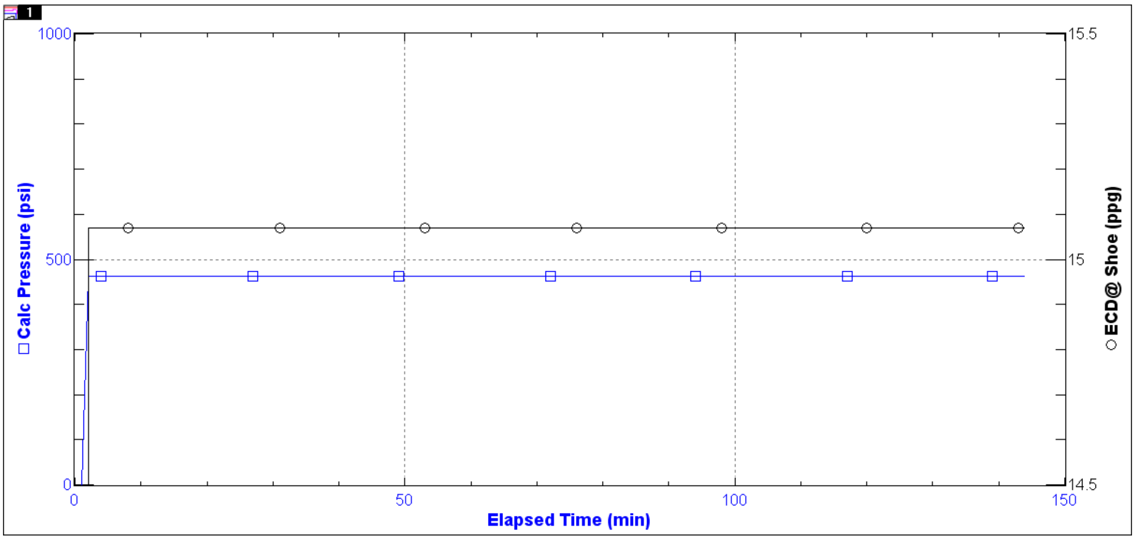


Figure 8-5 ECD and circulating pressure at the shoe versus time for Warp circulating at 6 BPM

CASE 2:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD). Warp OBM only with Baker ZX Packer at 4685 ft MD, circulating at 6 BPM.

In the second case Warp OBM was still used as mud type in the well. In, addition, a Baker ZX-packer was set at 4685 ft MD. The Warp OBM is circulated at 6 BPM. Figure D-0-8 illustrates the results from the simulations. In the figure one can observe that there will be a small increase in the ECD when the ZX Packer is used in the well. The reason for this increase in the ECD is that there will be a narrower flowing area for the mud across the packer. This will result in a higher frictional pressure loss when the packer is run on the casing. Despite this increase in the ECD, the fracture gradient will not be exceeded.
The ZX-packer set inside the previous shoe solves the gas migration problem for a while but increases the likelihood of ECD induced fracturing and losses at the shoe. By cementing the entire Miocene formation this packer is not necessary. The cement will then provide the required zonal isolation. This will improve the chances of cementing the entire Miocene section. Figure D-0-9 represents the circulating pressure and the ECD at the shoe plotted against time. The circulating pressure will be 492 psi and the ECD at the shoe will be 15.12 ppg. Compared with CASE 1 it is observable that there has been an increase in both the circulating pressure and the ECD at the shoe. The simulations show an increase of 0.04 ppg when circulating WARP OBM in the well with a ZX- packer in the hole compared with no packer. This is the best possible case. In real cases there is most likely cuttings and debris accumulation around the ZX-packer area making the annular clearance here even smaller. The ECD increase with a ZX-packer is therefore expected to be larger in real scenarios.

CASE 3:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD). Warp OBM only with HETS Expandable Casing at 4685 ft MD, circulating at 6 BPM.

In CASE3 the effect of using a HETS Expandable casing packer at 4685 ft is tested. This was done to see the difference in ECD between an expandable packer and the currently used mechanical ZX-packer. As in the two first cases, Warp OBM system is used with a circulation rate of 6 BPM. Compared with CASE1, where no annular casing packer is included, there no difference in the ECD. The ECD stays within the operational window for the entire well (Figure D-0-10). Figure D-0-11 shows that the circulating pressure and the ECD at the shoe is exactly the same as in CASE 1, 464 psi and 15.08 ppg, respectively. Compared with CASE 2 a lower ECD is seen with the expandable casing packer. Even though the increase in ECD with a ZX-packer from the simulations is not significant, it can be higher in a real case, due to cutting and debris accumulation at the around the packer

CASE 4:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD). Versatec OBM only circulating at 6 BPM.

In CASE 4 a new type of mud is introduced to the well. Versatec OBM is circulated in the well at 6 BPM. No packers are utilized in the well. Results from the simulation are represented in Figure D-0-12 and Figure D-0-13. Figure D-0-12 reveals that there will be a significant increase in the ECD when circulating with Versatec OBM compared with Warp OBM. The increase in the ECD is caused by the high viscosity of the Versatec OBM. In the bottom of the well the ECD will exceed the fracture gradient, and that losses will happen. Figure D-0-13 shows that Versatec will have a high impact on the circulating pressure and the

ECD at the production casing shoe. For this case the circulating pressure will be 807 psi and the ECD at the shoe will be 15.57 ppg.

CASE 5:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD). Versatec OBM only with Baker ZX Packer at 4685 ft MD, circulating at 6 BPM.

In CASE 5 a Baker ZX-Packer is run on the casing. Versatec OBM is still circulated in the well with a rate of 6 BPM. Figure D-0-14 and Figure D-0-15 show the results from the simulations. The circulating pressure at the shoe is 905 psi and the ECD at production casing shoe is 15.66 ppg. In Figure D-0-14 one can see that the packer causes a "jump" in the ECD (about 0.18 ppg), and this effect is higher than in CASE 2 where Warp OBM is used. The explanation to this is that the Versatec OBM is more viscous and the pressure drop will be higher across the packer. The Versatec mud and the ZX-packer is not an ideal combination. The Versatec is a thick mud and getting that mud past a restriction like the ZX-packer will increase the ECD substantially. The simulations show an increase of 0.09 ppg when circulating Warp OBM in the well with a ZX-packer in the hole compared with no packer. The ECD value in this case will not stay within the operational window and the fracture gradient will be exceeded. Values of the circulating pressure and the ECD at the shoe can induce losses to the formation near the production casing setting depth.

CASE 6:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD). Versatec OBM only with HETS Exp. Casing at 4685 ft MD, circulating at 6 BPM.

In CASE 6 the effect of introducing an HETS Expandable Packer to the casing string is evaluated. The packer is set at 4685 ft MD. The well is drilled with Versatec OBM at a circulation rate of 6 BPM. Figure D-0-16 and Figure D-0-17 show the results of the simulations. From Figure D-0-16 one can see that the ECD is exceeds the fracture gradient near the casing shoe. The ECD is here (almost) the same as with no packer in the well (0.01 ppg in difference). The circulating pressure is simulated to be 807 psi and the ECD at the shoe is simulated to be 15.58 ppg (Figure 12).

Cementing

Figure 8-6 shows the fluid location in the well. It can be seen from the figures that the TOC is located at 4895 ft MD/4767 ft TVD. This is a predetermined value. Based on this height, the volume cement needed is calculated to be 483 bbls. Fluid location will be the same with Versatec OBM and Warp OBM in the well. Figure D-0-5 represents the fluid location with Versatec in the well.

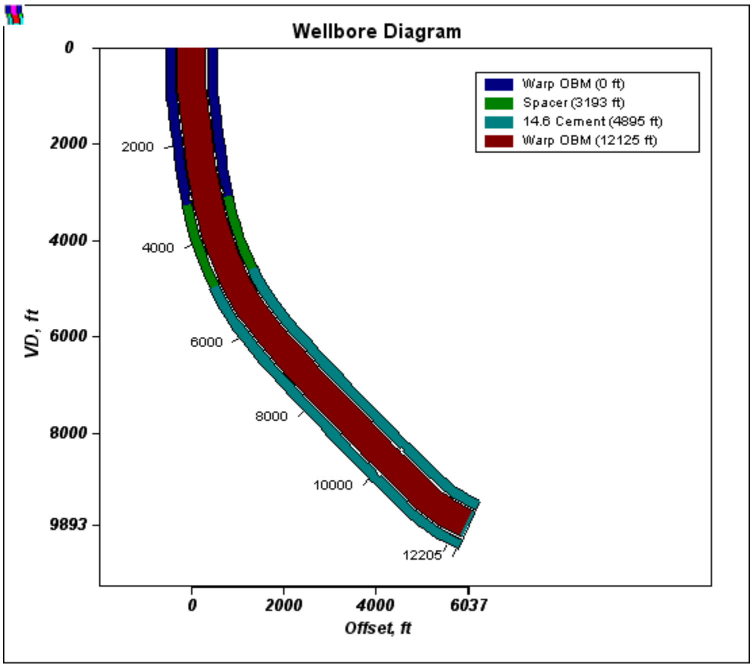


Figure 8-6 Fluid location

CASE 7:

Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD). Cement, Spacer and Warp OBM mixing/pumping at 5 BPM.

CASE 7 looks at the cement operation, and the cement, the spacer, and the Warp OBM are taken into consideration. The pumping rate is set to be 5 BPM. The rate is chosen 1 BPM lower than for only circulating prior to the cement job. The results of the simulations are illustrated in Figure D-0-18 and Figure D-0-19. The maximum ECD value (represented by the grey line) stays within the operational window in the entire well (Figure D-0-18). It is the maximum ECD value that is interesting parameter in this study. There is a higher ECD in this case than in CASE 1. This is because both spacer and cement is introduced and pumping these fluids will cause a higher pressure loss and thereby a higher ECD value. The effect of the spacer and the cement can be seen in Figure D-0-19. It can be seen that the spacer and cement comes into the well as an increase in ECD and circulating pressure with time. This is due to the difference in the rheology when spacer and cement are introduced in addition to the mud.
The circulating pressure is simulated to be 522 psi and the maximum ECD at the shoe is simulated to be 15.18 ppg

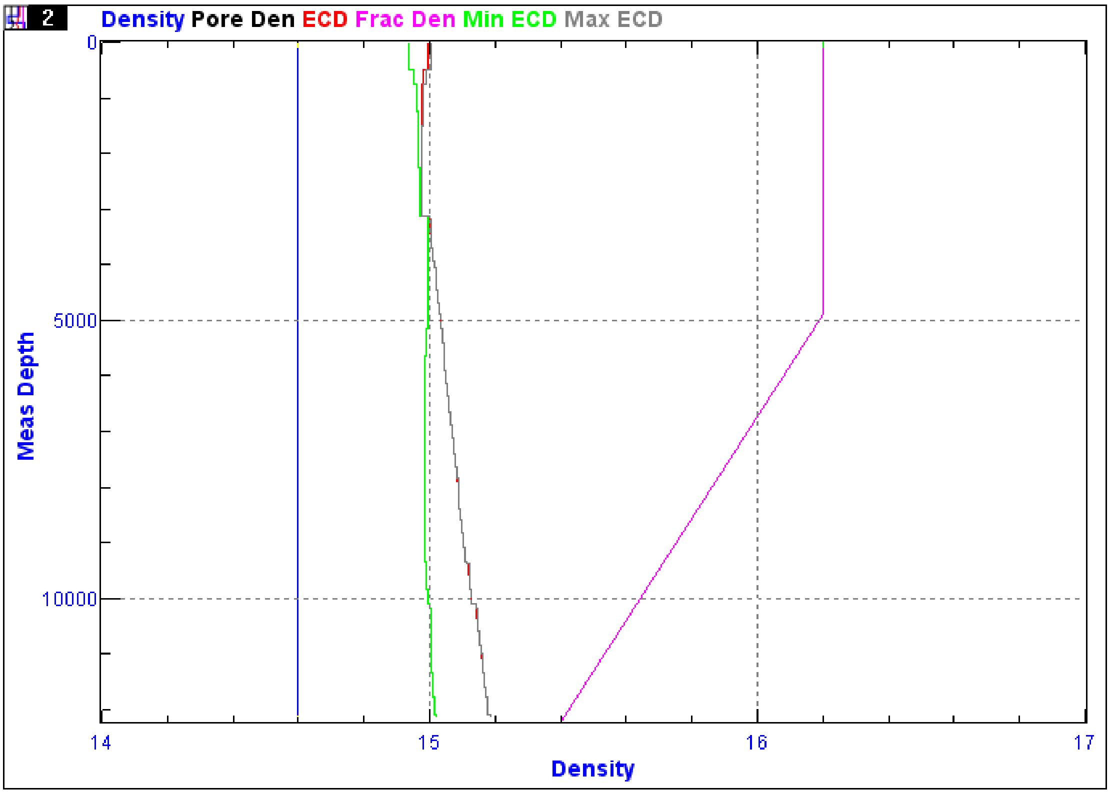


Figure 8-7 ECD compared with the fracture gradient when circulating cement, spacer and Warp OBM at 5BPM

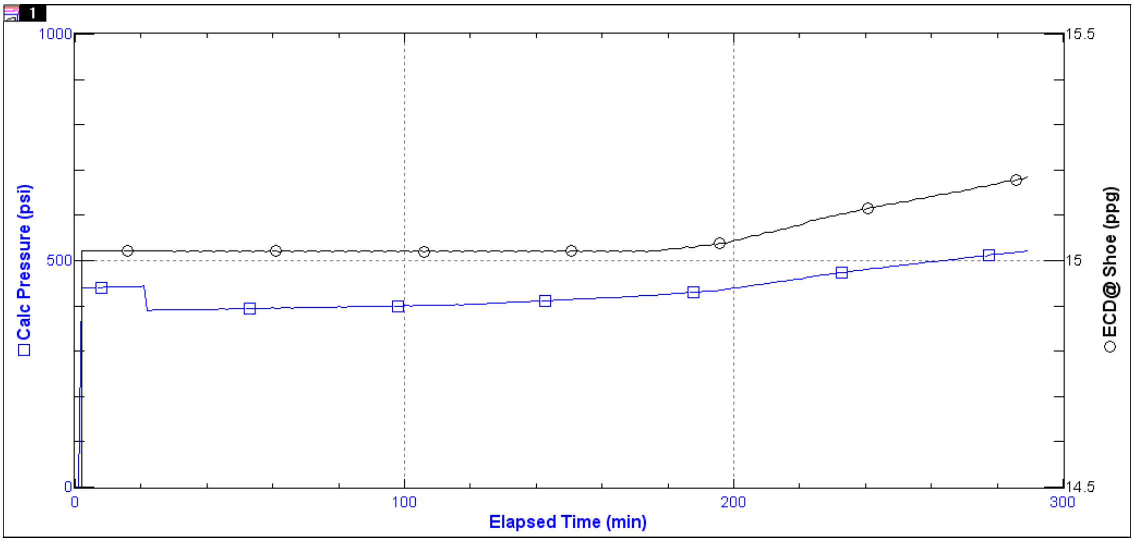


Figure 8-8 Circulating pressure and ECD at shoe when circulating cement, spacer and Warp OBM at 5BPM

CASE 8, CASE 9, CASE 11 and CASE 12 include cementing the entire Miocene with a casing annular packer in the well. This casing annulus packer is only a mitigation factor when the cement around the production packer is not sufficient. Cementing the entire Miocene section eliminates the need for an annular casing packer. In reality these cases would then ideally not be seen. Still, simulations were done to see the effect of the packers during cementing. This was due to the fact that unexpected losses to a natural fault may happen that leads to a cement height below the Miocene section. In addition, cementing the entire Miocene has never been done before and there might be some unexpected challenges like, reduced hole cleaning, therefore it can be discussed if an annulus casing packer should be run in at least the first attempt trying to cement the Miocene. It would be interesting to see how the cement operation is influenced by the casing packers.

CASE 8:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD) with Baker ZX Packer at 4685 ft MD. Cement, Spacer and Warp OBM mixing/pumping at 5 BPM.

In this case a Baker ZX-packer at 4685 is introduced; otherwise the case is similar to CASE 7. The pump rate is still 5 BPM. There will be a “jump” in the ECD at the depth where the packer is situated. The ECD will stay within the operational window during the entire well, although there are fewer margins than in CASE 7 (Figure D-0-20). Figure D-0-21 shows that there is a larger difference between the circulating pressure and the maximum ECD at the shoe, than in CASE 7.
The circulating pressure is modelled to be 522 psi and the maximum ECD at the shoe is simulated to be 15.8 ppg.

CASE 9:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD) with HETS Exp. Casing at 4685 ft MD. Cement, Spacer and Warp OBM mixing/pumping at 5 BPM.

In CASE 9 a HETS Expandable Packer is used in instead of the Baker ZX-packer, otherwise the case is exactly the same as CASE 8. Figure D-0-22 shows that by using HETS Expandable Packer the ECD value will be lower than when using the ZX-packer. Using the HETS Expandable Packer will not cause a “jump” in the ECD at the packer setting depth. The ECD will stay within the operational window for the entire well. The circulating pressure and the ECD at the production casing shoe is almost exactly the same as for CASE 7 with no packer in the well (Figure D-0-23). Since the effect of having a HETS packer in the well is only 0.01 ppg this is a good argument on that the packer should be run on the first cement job that is going to try to cement the entire Miocene section. If unexpected losses to a natural fault occur during cementing, leading to total losses, it would be good to have a casing packer in the well to stop any crude leaking up the B annulus.

CASE 10:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD). Cement, Spacer and Versatec OBM mixing/pumping at 5 BPM.

In CASE 10 cement, spacer and Versatec OBM is pumped at 5 BPM in the well. Figure D-0-24 shows that the fracture gradient will be exceeded in this case and the formation will be fractured. It is not recommended to cement the entire Miocene with Versatec mud in the well. This case will most likely induce losses to the formation. The final circulating pressure is simulated to be 668 psi and the maximum ECD at the shoe is simulated to be 15.46 ppg (Figure D-0-25).

CASE 11:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD) with Baker ZX Packer at 4685 ft MD. Cement, Spacer and Versatec OBM mixing/pumping at 5 BPM

In CASE 11 cement, spacer and Versatec OBM is pumped into the well at 5 BPM. In addition, a Baker ZX-packer is run at the casing at 4685 ft MD. The results of the simulations are presented in Figure D-0-26 and Figure D-0-27. It is clear that this case will exceed the fracture gradient and cause lost circulation in the well (Figure D-0-26). In this case the formation will be fractured even earlier than in CASE 10. Figure D-0-27 shows that the circulating pressure will be 698 psi and the maximum ECD at the shoe will be 15.56 ppg.

CASE 12:
Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD) with HETS Expandable Casing Packer at 4685 ft MD. Cement, Spacer and Versatec OBM mixing/pumping at 5 BPM

In CASE 12 cement, spacer and Versatec is pumped at 5 BPM into the well. An HETS Expandable casing packer is run at the casing at 4685 ft MD. The ECD will exceed the fracturing pressure of the formation in this case also (Figure D-0-28). The results are almost the same as in CASE 10, where no packers have been applied. The final circulating pressure and ECD at the shoe is also almost the same as in CASE 10 (Figure D-0-28).

8.2.1.2 Liner 9 7/8”

<u>Mud Circulation</u>
CASE 13:
9 7/8-in liner set at 12205 ft MD (9893 ft TVD). Warp OBM only with Versaflex LH circulating at 6 BPM

In CASE 13 the 9 7/8 in liner set at 12205 ft MD (9893 ft TVD) is evaluated. Warp OBM is circulated in the well at 6 BPM. Figure D-0-30 shows that there will be a dramatically increase in ECD (about 1.2 ppg) across the Versaflex liner hanger. The ECD will exceed the fracture gradient in the lower part of the well and cause lost circulation. The circulation pressure is calculated to be 767 psi and the ECD at the shoe is 15.53 ppg for this case (FigureD-0-31).

CASE 14:
9 7/8-in liner set at 12205 ft MD (9893 ft TVD). Warp OBM only with Baker ZXP LH circulating at 6 BPM.

In CASE 14 another type of liner hanger, the Baker ZXP liner hanger, is tested in the well. Warp OBM is circulated in the well at 6 BPM. Figure D-0-32 reveals that the ECD will stay within the operational window through the entire well. It is interesting to see the difference from CASE 13 where another type (Versaflex) is used. Figure D-0-33 represents the circulating pressure and the ECD at the shoe plotted against time. The circulating pressure and ECD at shoe is simulated to be 497 psi and 14.98 ppg respectively.

CASE 15:
9 7/8-in liner set at 12205 ft MD (9893 ft TVD). Versatec OBM only with Versaflex LH circulating at 6 BPM.

CASE 15 definitely shows that the fracture gradient is exceeded in the entire hole section below the 13 3/8” casing; the pressure simulated just below the 13 3/8” shoe is almost 16.85 ppg. This is way more than the formation can take. The simulation shows that a combination of the Versaflex liner hanger and circulating Versatec mud at 6 BPM will definitely fracture the formation (Figure D-0-34).The circulating pressure in this case was 1245 psi and the ECD at the shoe was 16.14 ppg (Figure D-0-35).

The wells drilled and completed on the Ekofisk M-platform have used this combination of Versatec mud and the Versaflex liner hanger on all the wells, but the flow rate was lower and around 4 BPM for most of the cases. This low value of flow rate is not recommended from a hole cleaning and cement operation perspective, but is the only chance to reduce the risk of losses. Studying how the cement job went on these wells show that 14 of 26 wells had losses (above 10 bbl).

CASE16:
9 7/8-in liner set at 12205 ft MD (9893 ft TVD).Versatec OBM only with Baker ZX LH circulating at 6 BPM.

In CASE 16 the Versaflex liner hanger in CASE 15 was exchanged with a Baker ZX packer. The rest of the parameters are the same as in CASE 15. Comparing CASE 15 with CASE 16 shows that the mechanical packer actually gives a much lower ECD than the Versaflex liner hanger (Figure D-0-34 and Figure D-0-36). The ECD actually stays below the fracture gradient for the entire hole section. The circulating pressure was in this case 792 psi, and the ECD at the production casing shoe was 15.38 ppg. The difference in ECD at the production casing shoe between CASE 15 and CASE 16 is 0.76 ppg (Figure D-0-35 and Figure D-0-37). The difference in ECD at right below the previous casing for CASE 15 and CASE 16 is 1.79 ppg.

Cementing

Figure 8-9 and Figure 8-10 below shows the fluid locations when cementing the liner. Figure 8-9 shows displacing the cement with one constant flowrate of 5 BPM. In Figure 8-10 two different flow rates are used, 5 BPM and then lowered to 3 BPM

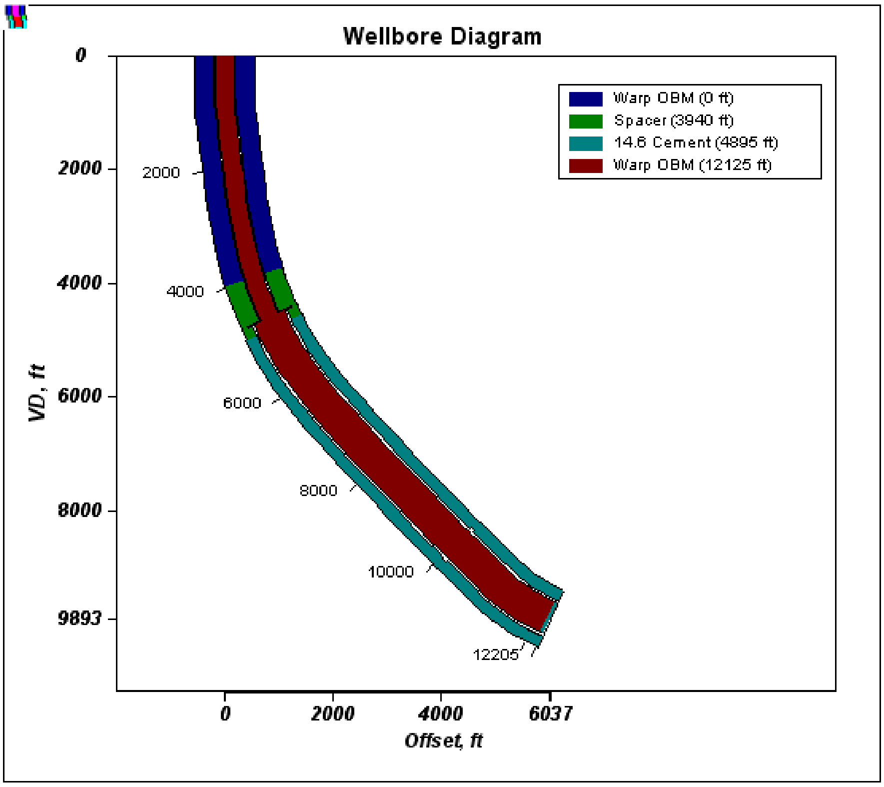


Figure 8-9 Fluid location liner with constant flow rate (5 BPM)

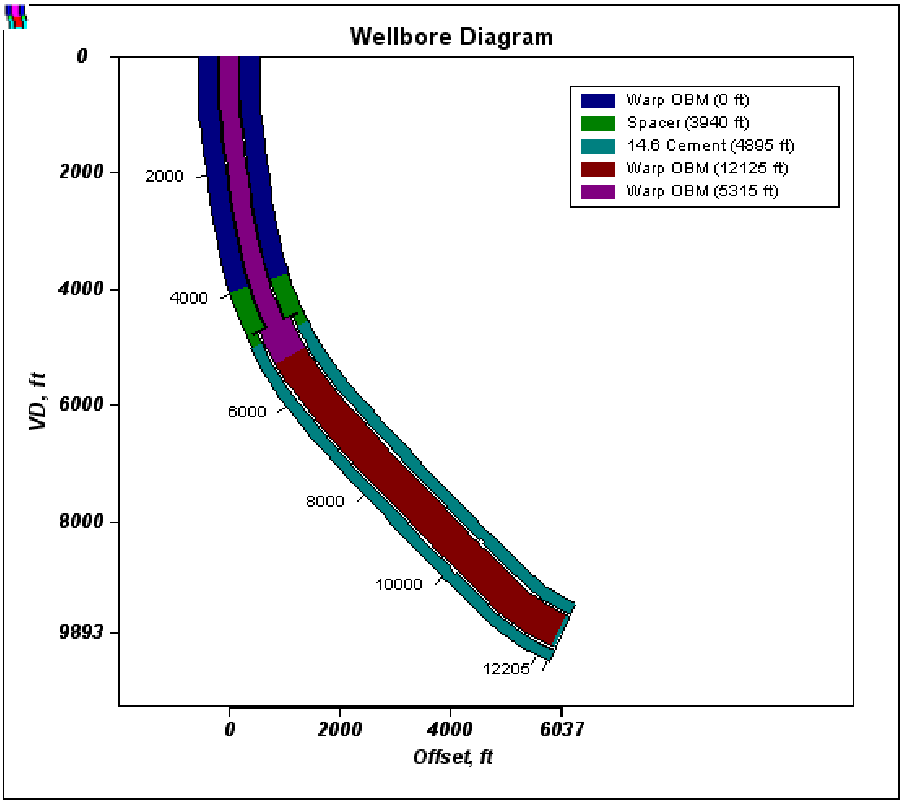


Figure 8-10 Fluid location liner with two different flow rates (3 BPM and 5 BPM)

CASE 17 to CASE 19 is simulated on a 9 7/8" liner set at 12205 ft MD (9893 ft TVD) the top of the liner is 200 ft MD into the previous 13 5/8" casing. These cases show three different ECD scenarios during cementing. In CASE 17 a Versaflex liner hanger was simulated with a fluid flow rate of 5 BPM. In CASE 18 a Versaflex liner hanger was simulated with flow rate of 5BPM x 3 BPM. In CASE 19 a Baker ZXP-packer liner hanger was simulated, Warp OBM was displaced at 5 BPM.

CASE 17 was made to simulate the ECD during cementing the well, with a Versaflex liner hanger and Warp OBM in the well. Result from this simulation is illustrated in Figure D-0-40 and Figure D-0-41. It can be seen that the ECD is higher than the fracture gradient. The final circulating pressure is 871 psi and the ECD at the shoe is 15.78 ppg. Figure D-0-41 shows that the ECD increase drastically after about 220 minutes of pumping and displacing. This ECD jump is caused by the spacer being pumped through the liner hanger. Since the spacer is more viscous than the Warp mud the ECD will increase a lot in this small clearance. To reduce the ECD a new simulation was done with keeping all the same parameters except changing the flow rate to 3 BPM right before the spacer reaches the liner hanger (CASE 18). Figure D-0-42 and Figure D-0-43 shows the effect of decreasing the flowrate before the spacer reaches the liner hanger. Final circulating pressure is 871 psi and the ECD at the production liner shoe is 15.78 ppg. From Figure D-0-43 it can be seen that when the flow rate is reduced it results in a great reduction in ECD. Then, after some minutes, an increase can be seen again. This is the increase due to the spacer. Comparing the two cases shows that the ECD increase due to the spacer is lower for reduced flow rate in CASE 18. It can be seen by comparing Figure D-0-41 and Figure D-0-43 that the ECD is reduced from 15.78 ppg to 15.40 ppg when the flowrate is reduced from 5 BPM to 5 BPM and 3 BPM. This reduction in the ECD can have a dramatic effect on the cement job. As already mentioned, the fracture gradient at the shoe setting depth is difficult to predict. Therefore, a reduction in ECD of 0.38 ppg can be very beneficial to reduce lost circulation.

The displacement efficiency can also be seen in CemFacts. Two-dimensional models like CemFacts allow good analysis of either axial-radial flow (e.g. predicting the size of the mud layer on the walls) or axial-azimuthal flow, e.g. mud channels. The latest models take erosion of static layers into account and can be used in all borehole shapes and annuli sizes. This makes them ideal tools for parametric studies combining all the relevant forces acting together. Figure D-0-44 and Figure D-0-48 shows the results from the displacement efficiency for CASE 18 and CASE 19, recpectively. The displacement efficiency if the casing has only 40 % standoff for the same two cases is shown in Figure D-0-45 (CASE18) and Figure D-0-49 CASE 19). Figure D-0-44 shows that CASE 18 will leave a very small amount of spacer at the narrow side at about 6500 ft MD. It can be seen that the standoff is low over a longer area at this depth in the standoff curve to the left in the figure. This will reduce the displacement efficiency of the spacer on the narrow side. Figure D-0-48 shows that keeping the flowrate constant at 5 BPM with a ZXP liner hanger will improve the displacement. For 60 % standoff the mud and spacer in the whole well is 100% displaced. It can be seen from Figure D-0-49 and Figure D-0-45 that by lowering the standoff to 40%, the displacement efficiency decreases. The black parts seen on the figures illustrate the gelled mud in the well. As expected, the displacement efficiency for CASE 18 is better than for CASE 19. The displacement efficiency is still acceptable, due to the large volume pumped. By cementing back up in the previous casing string the chances for having cement column that provides zonal isolation is increased.

Simulations with the cementation of the liner hangers were basically done with Warp mud since the previous circulation modelling showed that the Versatec will most likely give a too high ECD, especially with Versaflex liner hanger. To see the displacement efficiency with Versatec, **CASE 20** in the well a simulation was done with Versatec mud instead of Warp for the ZXP liner hanger as in CASE19. The displacement figure shows that there will be some mud left close to the narrow side in the annulus. The black color represents gelled mud in the displacement figures (Figure D-0-52). For the case with 40% standoff the displacement would be even worse and to much gelled mud is left ion the narrow side (Figure D-0-53). The marine blue colour represents Versaflex mud. Figure D-0-50 shows that the ECD will stay below the fracture gradient chosen, but e relatively close. In combination with (Figure D-0-48 and Figure D-0-52) showing the displacement, the overall recommendation is to use the Warp mud prior during cementation.

In Table 8-2 a summary of the results from this simulation study is presented. The table is showing the ECD at the production casing/liner shoe for the nineteen cases studied.

Table 8-2 Simulation results casing

9 5/8”x 9 7/8” Casing			
CIRCULATING			
Warp OBM		Versatec OBM	
CASE1: Circulating no packer at 6 BPM	ECD = 15.08 ppg	CASE4: Circulating no packer at 6 BPM	ECD = 15.57 ppg
CASE2: Circulating with ZX- Packer at 6 BPM	ECD = 15.12 ppg	CASE5: Circulating with ZX packer	ECD = 15.66 ppg
CASE3: Circulating with HETS expandable packer at 6 BPM	ECD = 15.08 ppg	CASE6: Circulating with HETS expandable packer at 6 BPM	ECD = 15.58 ppg
CEMENTING			
Warp OBM		Versatec OBM	
CASE7: Cementing no packer at 5 BPM	ECD = 15.18 ppg	CASE10: Cementing at 5 BPM	ECD = 15.46 ppg
CASE8: Cementing with ZX-packer at 5 BPM	ECD = 15.25 ppg	Case11: Cementing with ZX-packer at 5 BPM	ECD = 15.65 ppg
CASE9: Cementing with HETS-packer at 5 BPM	ECD = 15.19 ppg	CASE12: Cementing with HETS-packer at 5 BPM	ECD = 15.47 ppg

9 7/8” Liner			
CIRCULATING			
Warp OBM		Versatec OBM	
CASE13: Circulating with Versaflex liner hanger at 5 BPM	ECD = 15.53 ppg	CASE15: Circulating Versaflex liner hanger at 5 BPM	ECD = 16.14 ppg
CASE14: Circulating with Baker ZXP liner hanger at 5 BPM	ECD = 14.98 ppg	CASE16: Circulating with Baker ZXP liner hanger at 5 BPM	ECD = 15.38 ppg
CEMENTING			
Warp OBM		Versatec OBM	
CASE17: Cementing Versaflex liner hanger at 5 BPM	ECD = 15.78 ppg		
CASE18: Cementing Versaflex liner hanger at 5 x 3 BPM	ECD = 15.40 ppg		
CASE19: Cementing with Baker ZXP liner hanger at 5 BPM	ECD = 15.13 ppg	CASE20: Cementing with Baker ZXP liner hanger at 5 BPM	ECD = 15.32 ppg

8.2.2 Observations

- Warp OBM system is superior to Versatec OBM system from a well cementing perspective, i.e. the lower fluid rheologies and lower static gel strength values promote better mud displacement efficiency and lower ECD's during cementing. However, Warp OBM does not have the solids carrying capacity of Versatec OBM, so hole cleaning will not be as efficient. It is well known that hole cleaning has a major impact on the cement performance. If the hole is not properly cleaned it can leave mud channels or muds layers in the cement or at the casing/formation walls and create interzonal communication. A solution may be to drill the well with Versatec mud. Circulate the well clean and then change to Warp mud prior to running the casing. While drilling, the conditions for mud displacement are different than for displacement during the cement operation. During drilling the annular clearances are much larger than with a casing in the well. This makes the ECD lower with a drill string in the well keeping all the other parameters constant.

- HETS Expandable Casing packer will have no effect on the ECD during circulation or cementing.

- Simulations show that it is not possible use the Baker ZX-packer when circulating with Versatec OBM at 6 BPM.

- Comparing the different ECD scenarios show that the 9 5/8 x 9 7/8" (without casing packer) casing string gives a lower ECD than the 9 7/8" liner. From the simulation it can be seen that the reason for this is the increase in ECD due to small annular clearances in the liner hanger. However, the ECD produced when pumping cement, spacer and Warp mud with the full 9 5/8"x 9 7/8" casing string containing the ZP Packer is 15.25 ppg compared to a 15.13 ppg ECD in the Baker ZXP liner scenario with the same fluids and pump rate.

- The Baker ZXP liner hanger produces a lower cement placement ECD than the Versaflex liner hanger. However, the Versaflex liner hanger can be rotated, which will promote improved mud displacement efficiency. Also, the hanging-off and packing-off of the Versaflex liner is pressure activated, the hanging off and setting of the liner top packer of the Baker ZXP liner requires two separate operations. In the case of the Baker ZXP liner, any cement above the liner hanger may be static for up to 45 minutes prior to release of the running tool. This produces a higher mechanical risk, as the cement above the liner top may gain sufficient static gel strength in 45 minutes to produce excessive pressure while reversing the excess cement. The Versaflex liner hanger has a metal to metal seal which makes it more a more reliable seal during the lifetime of the well, than the ZXP liner hanger. The increased ECD produced by the Versaflex hanger can be decreased by lowering the displacement rate of the cement.

- In order to properly access the liner cementing operation from an ECD perspective, the geometry of liner hanger must be taken into account, as the hanger (and PBR) this imposes the most significant annular restriction.

- The light weight cement simulated has a good displacement efficiency, especially when used together with Warp OBM.

9 Conclusions

The objective of this thesis was to investigate how the cement job on the production casing set immediately above the reservoir can be improved. In this chapter the findings from the studies will be presented. In addition, final suggestions on how to improve the cement job are given. The final suggestions are divided in two groups:

1) TOC 330 ft above the top of Balder formation.

2) Cementing back to the previous casing shoe.

In addition, some recommendations for further work are given.

Simulations in WellPlan™

- The WellPlan™ Cementing module, WellPlan™-Opticem, was used for the first time in the North Sea Business unit (NSBU) to look at cementing design analysis. Original OptiCem files were imported into WellPlan™-OptiCem for three wells. The outputs in WellPlan™-OptiCem were very different from the ones in OptiCem for all the wells imported.

- There are still a lot of challenges that is needed to be overcome before an Opticem file can be completely imported into WellPlan™-Opticem and simulated. Further work should be done on this area to improve the import of files.

- Cement job records need to be improved. Due to lack of a data storage system, important cement job data that allows studying and improving the cement success on the production casing in the Ekofisk and Eldfisk fields, were lost.

- As a result of this work, a new system to store cement data was recommended and established.

Simulations in CemFacts

- Warp OBM system is superior to Versatec OBM system from a well cementing perspective, i.e. the low fluid rheologies and low static gel strength values promote better mud displacement efficiency and lower ECD during cementing.

- HETS Expandable Casing packer will have no effect on the ECD during circulation or cementing.

- Simulations show that it is not possible to stay within the operational window when using a Baker ZX-Packer when circulating with Versatec OBM at 6 BPM.

- Comparing the different ECD scenarios show that the 9 5/8" x 9 7/8" casing string gives a lower ECD than the 9 7/8" liner. From the simulation it can observed that the reason for this is the increase in ECD, due to small annular clearances in the liner hanger.

- In order to properly assess the liner cementing operation from an ECD perspective, the geometry of liner hanger must be taken into account, as the hanger (and PBR) imposes the most significant annular restriction.

- The Baker ZXP liner hanger produces a lower cement placement ECD than the Versaflex liner hanger.

- The increased ECD caused by the Versaflex hanger can be decreased by lowering the displacement rate of the cement.

- A low ECD liner would be very beneficial for reducing the ECD and achieving a good cement job.

Evaluation of historical cement jobs on the Ekofisk and Eldfisk fields

- No trends were found between rotation of the liner and lost circulation.

- The casing setting depth in the Våle formation was on average 65.5 % for the M-wells. This is very close to the recommended setting depth of 67 % into the Våle formation, which indicates that there are good procedures for predicting the right casing setting depth.

- Wells drilled over 67 % into the Våle formation have a higher chance of lost circulation.

- No inclination trends on lost circulation during cementing were indicated by the drilled wells.

<u>330 ft above the production packer or top of Balder:</u>

<u>9 5/8” casing in 13 3/8” casing (Ekofisk X-design and Eldfisk design)</u>

- Change the currently used ZX-packer with a Read expandable packer

- Run a stage tool at a depth that can be sealed off by the liner hanger as a redundancy solution.

- Simulations showed that the swellable packer gave no extra increase in ECD. Swellable packers should be run as a back up above the TOC. The ideal setting point of the swellable packer would be right above the Miocene gas, but deep enough the 13 3/8” shoe to avoid setting the packer in a washed out area. A sonic log should be run to check the setting depth area for wash outs. It is important to have a long swelling delay on both a diffusion barrier and the rubber element, in case the casing gets stuck. A swellable packer is especially needed on the X-wells due to the overall higher Miocene gas recordings.

- If the new well is sidetracked out of 13 3/8” casing it can improve the cement job quality by running a 9 7/8” liner compared to a full 9 7/8” casing string. Note that this can only be done if the intermediate 13 3/8” casing string is of high enough quality to become a part of the production casing. On the Ekofisk field about ¼ of the wells have the 13 3/8” casing integrity needed. Simulation shows that a liner will give a much higher ECD than a full string due to the Versaflex liner hanger restriction. The benefits from being able to rotate the liner will be bigger than having a lower ECD. The ECD can be managed by pumping slower. Rotation will give a much better cement quality especially in high angle wells as it may yield the mud trapped on the narrow side. This will make the TOC level higher, with the fact that the TOC is represented by the narrow side.

<u>10” liner in 13 5/8” casing (Ekofisk M-design)</u>

- The M-Wells have had an overall better success when foam cementing the production liner than the Ekofisk X and Eldfisk A wells.
- The results from the CemFact simulations on the expandable liner hangers, which are used on all the M-wells, give a very high ECD. This liner hanger should in the future be changed out with a new low ECD expandable liner hanger.
- Simulations show that there is a lower ECD by having a full casing string compared to a liner of same dimension. But the overall benefits from being able to rotate the liner are higher.

Cementing the entire Miocene Section (cement into the previous casing shoe):

- The wells best fitted to try to meet this target is a K-well, due to their well design and cementing procedure. If drilling of the section and running the liner is not a problem it is suggested to try to cement the entire Miocene in one stage. This can be done within the operational window. Due to rig limitations the long 7 3/4” liner cannot be foam cemented and will be cemented with light weight cement instead. The K-wells are water injection wells and the reservoir pressure is high. This makes the K-wells extra important to cement to keep the barrier envelope in place.

- Simulations show that the X-wells can be foam cemented to the previous casing shoe with this light weight cement within the operational window. This requires Warp technology mud in the wellbore and a properly prepared and clean hole.

- The lower quality of foam cement will solve the logistical challenges on the jack-up rig with cementing the entire Miocene with foam cement.

- The upcoming Viktor Alpha injector rigs can use foam cement to cement the entire Miocene, with Warp mud in the well and low displacement rate (3-4 BPM)

Recommendation for further work

- There exists one official mud window for the entire Ekofisk field and one official mud window for the entire Eldfisk field. Therefore, the mud windows used in well design and planning are field wide and do not take into account more localized stress effects.

In real cases there will in some areas be a higher frequency of faulting or evidence of increased stress profiles. These can be characterized by a significant amount of casing deformation. In the future it will be a big benefit to have a more area specified operational window that takes into account the levels of depletion in the field and the changes in the gradients throughout the field.

- Enhanced hole cleaning. Hole preparations are important to achieve a good cement job.

- Include the right TOC in the barrier schematic. Losses should be taken into account

- CBL can be beneficial to run if there are changes in the cement procedure. The CBL will then be able to evaluate and tell if the adjustments went as planned. Based on this information it can be decided on either to continue with the new approach or if looking for other options are needed.

- Start using the READ expandable casing packer instead of the mechanical ZX-packer to reduce the ECD during circulation and cementing.

- The READ packer should be set as deep as possible (i.e close to the 13 3/8" shoe), to allow safe P&A of the well in the future.

- Start investigating the possibilities for designing a low ECD expandable liner hanger for the 9 7/8" 68.8 lbm/ft production liner.

- For future wells the procedure of spotting a LCM pill must be evaluated accordingly depending on well behaviour. A LCM pill pumped that is not necessary may lead to a stuck casing or increase the ECD during circulation and the cement job leading to lost circulation.

Nomenclature

9.1 Abbreviations

BHA	Bottom Hole Assembly
BPM	Barrels per Minute
COPNO	ConocoPhillips Norway
DHDF	Down Hole Drilling Fluid
ECD	Equivalent Circulating Density
ECP	External Casing Packer
EMW	Equivalent Mudweight
FIT	Formation Integrity Test
FO Collar	Full Opening Collar
GR	Gamma Ray
LCM	Lost Circulation Material
LOFS	Life of File Seismic
LOT	Leak Off Test
mD	Millidarcy
MW	Mudweigth
OBM	Oil Based Mud
OD	Outer Diameter
P&A	Plug and Abandonment
ROP	Rate of Penetration
RPM	Rotations Per Minute
SOA	Seismic Obstructed Area
STB	Stock Tank Barrel
TD	Total Depth
TOC	Top of Cement
TOE	Top of Ekofisk
TVD	True Vertical Depth
VA	Viktor Alpha
VSP	Vertical Seismic Profile
WBE	Well Barrier Element
XLOT	Extended Leak Off Test

9.2 Symbols

σ':	Total stress
P_o:	Pore pressure
β:	Biot constant
σ_{o1}:	Vertical overburden stress
P_{o1}:	Pore pressure before depletion
P_{o2}:	Pore pressure after depletion
σ_{H1}:	Horizontal stress
σ_{o2}:	Vertical overburden stress after depletion
$\sigma_{o2}^{'}$:	Vertical effective overburden stress after depletion
g:	Gravitational constant
$\sigma_{o1}^{'}$:	The effective overburden stress
ν:	Poisson's ration
$\Delta\sigma_a$:	Horizontal stress change
Δp_{wf}:	Change in fracture gradient
σ_x:	Stress acting in the x-direction
σ_y:	Stress acting in the y-direction
σ_z:	Stress acting in the z-direction
θ:	Angular position on borehole wall from x-axis
τ:	Shear stress
$\tau_{\theta z}$:	Shear stress
τ_{xy}:	Shear stress
τ_o:	Yield stress
τ_y:	Yield stress
σ_H:	Maximum horizontal in-situ stress
σ_h:	Minimum horizontal in-situ stress
σ_v:	Overburden stress
δ:	Cohesive strength
ρ_{mud}:	Density of mud
ρ:	Density
$u_{\max}$:	Maximum velocity
r:	Distance from center of pipe
R:	Radii of pipe
μ:	Viscosity
μ_{eff}:	Effective viscosity
$\frac{dP}{dz}$:	Pressure gradient along the pipe.
Re:	Reynolds number
Re_{crit}:	Critical Reynolds number

D:	Pipe diameter
n:	Flow behavior index (dimensionless)
K:	Flow consistency index/correlation factor dependent on the unit system utilized
γ:	Shear rate/inclination
$°F$:	Degrees Fahrenheit
Q_{foam}:	Quality of foam
V_{gas}:	Volume gas
V_{foam}:	Volume foam
$V_{downhole}$:	Downhole flowrate
$V_{surface}$:	Surface flowrate
f:	Foam fraction
E:	Erodibility
γ:	Shear rate
U:	Velocity
P_h:	Hydrostatic pressure

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Appendix A NORSOK Standard D-010

Table A-1 NORSOK STANDARD D-010 Table 22 - Casing Cement

15.22 Table 22 – Casing cement

Features	Acceptance criteria	See
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A design and installation specification (cementing programme) shall be issued for each primary casing cementing job. 2. The properties of the set cement shall be capable to provide lasting zonal isolation and structural support. 3. Cement slurries used for isolating permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. The cement placement technique applied should ensure a job that meets requirements whilst at the same time imposing minimum overbalance on weak formations. ECD and the risk of lost returns during cementing shall be assessed and mitigated. 5. Cement height in casing annulus along hole (TOC): 5.1 **General:** Shall be 100 m above a casing shoe, where the cement column in consecutive operations is pressure tested/the casing shoe is drilled out. 5.2 **Conductor**: No requirement as this is not defined as a WBE. 5.3 **Surface casing**: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be inside the conductor shoe, or to surface/seabed if no conductor is installed 5.4 **Casing through hydrocarbon bearing formations**: Shall be defined based on requirements for zonal isolation. Cement should cover potential cross-flow interval between different reservoir zones. For cemented casing strings which are not drilled out, the height above a point of potential inflow/ leakage point / permeable formation with hydrocarbons, shall be 200 m, or to previous casing shoe, whichever is less. 6. Temperature exposure, cyclic or development over time, shall not lead to reduction in strength or isolation capability. 7. Requirements to achieve the along hole pressure integrity in slant wells to be identified.	ISO 10426-1 Class 'G'
D. Initial verification	1. The cement shall be verified through formation strength test when the casing shoe is drilled out. Alternatively the verification may be through exposing the cement column for differential pressure from fluid column above cement in annulus. In the latter case the pressure integrity acceptance criteria and verification requirements shall be defined. 2. The verification requirements for having obtained the minimum cement height shall be described, which can be • verification by logs (cement bond, temperature, LWD sonic), or • estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc.). 3. The strength development of the cement slurry shall be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. For HPHT wells such equipment should be used on the rig site.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the cement well barrier shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet to be visually observed regularly.	WBEAC for "wellhead"
G. Failure modes	Non-fulfilment of the above requirements (shall) and the following: 1. Pressure build-up in annulus as a result of e.g. micro-annulus, channelling in the cement column, etc.	

Appendix B Swell packer simulations in Swellsim®

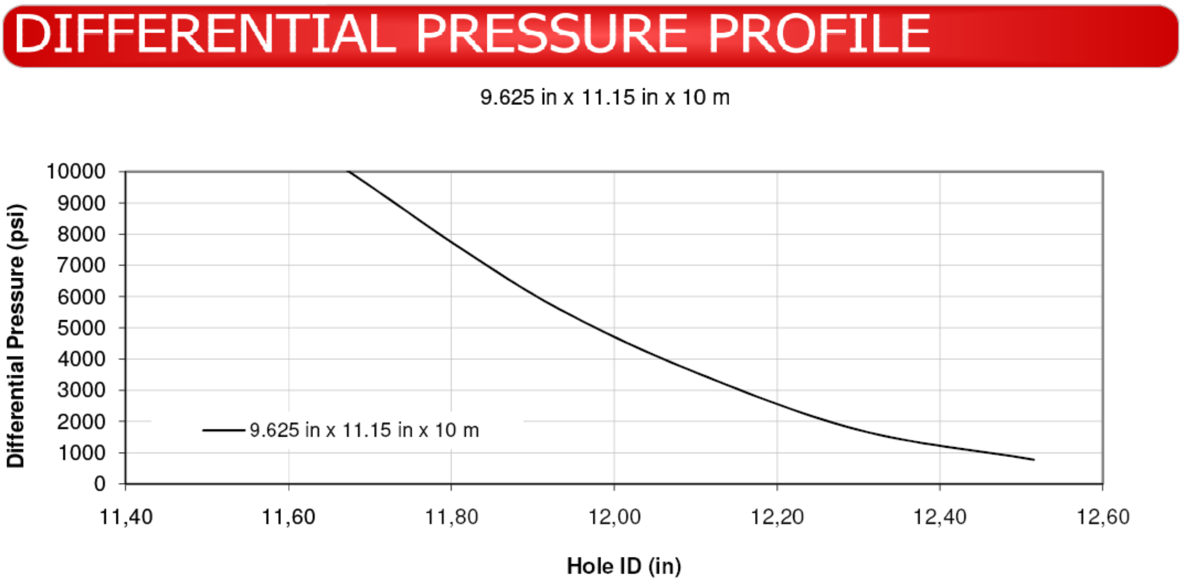


Figure B-0-1 Differential pressure profile for swell packer dimension 9.625 in x 11.15 in x10 m

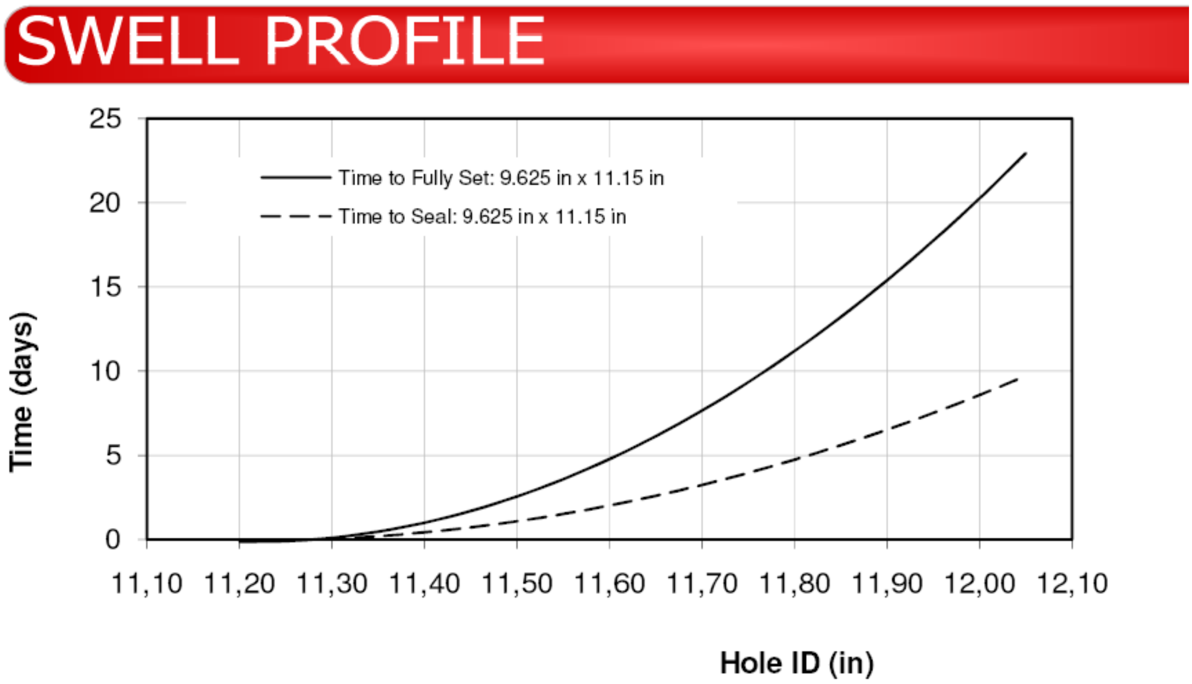


Figure B-0-2 Swell profile swell packer dimension 9.625 in x 11.15 in x10 m

Appendix C Virtual Hydraulic simulation of swell packer

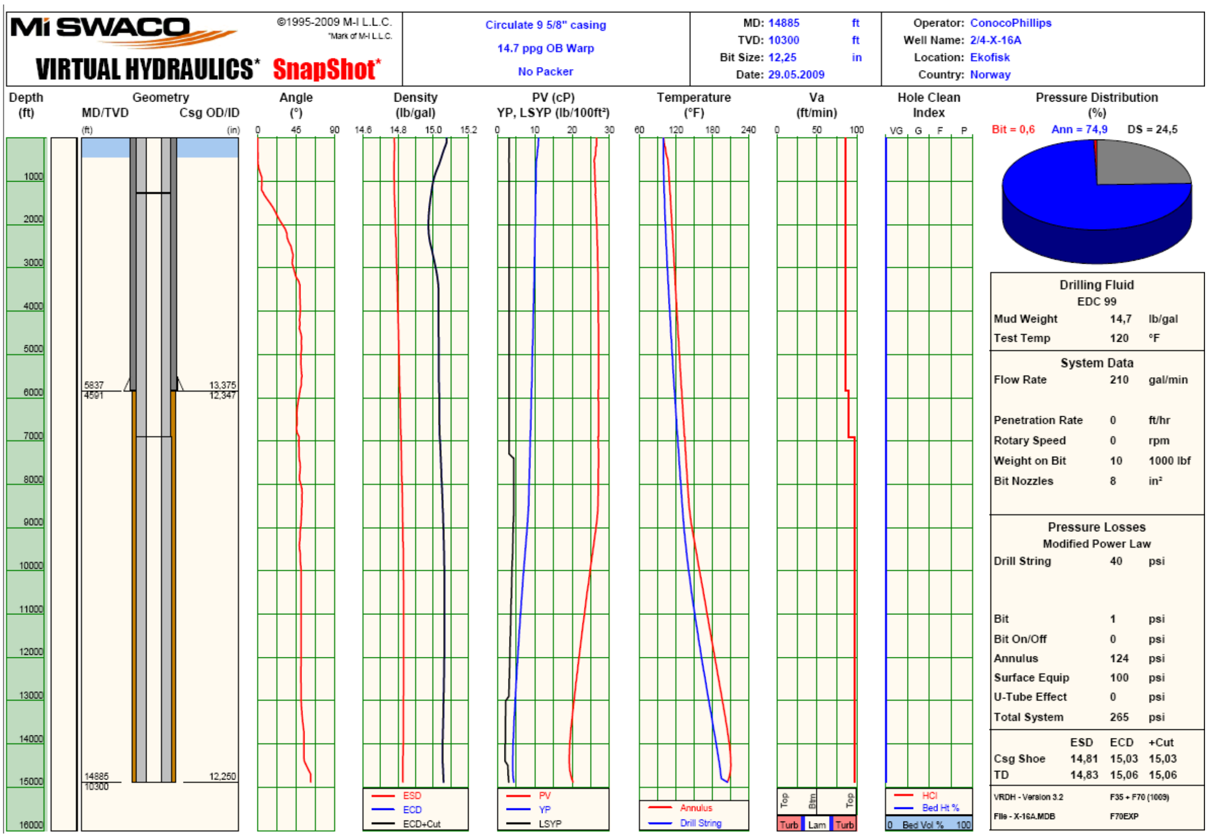


Figure C-0-1 Virtual Hydraulics simulation with Warp (no packer)

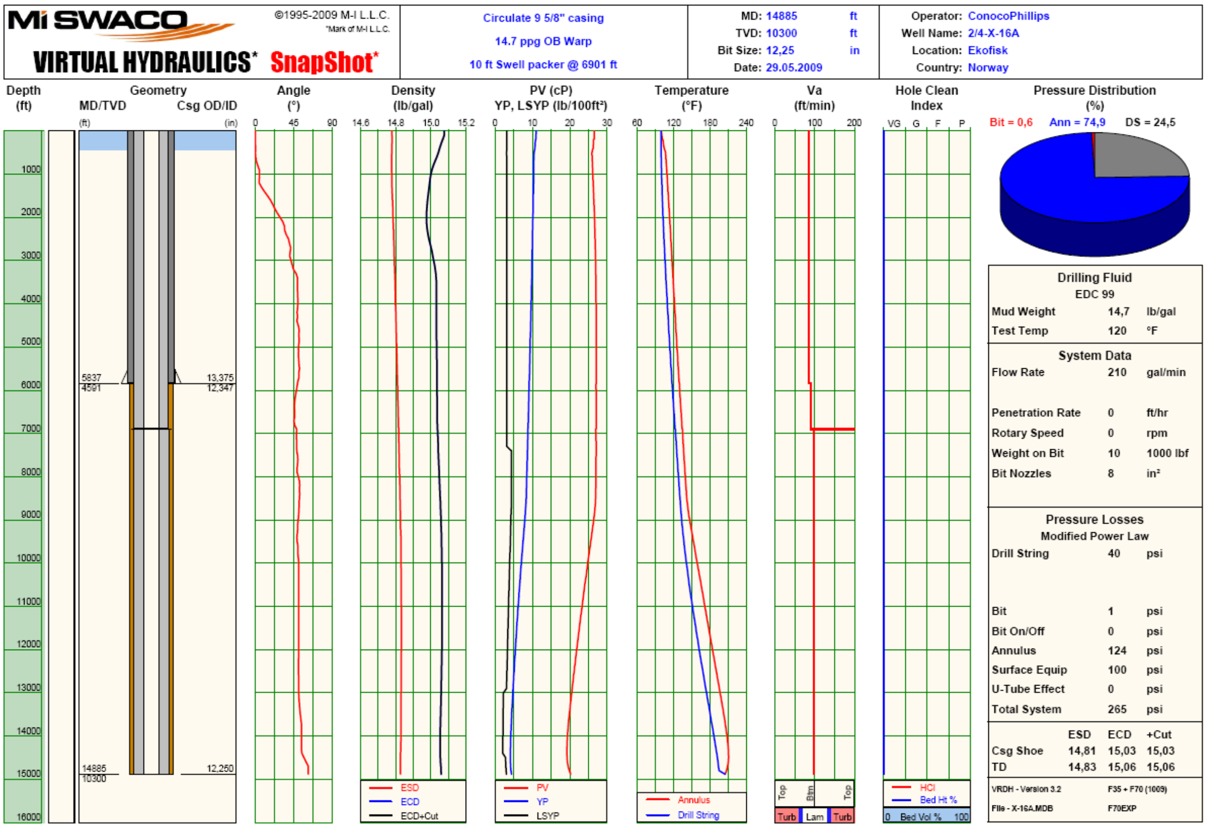


Figure C-0-2 Virtual Hydraulics simulation with Warp (Swellpacker)

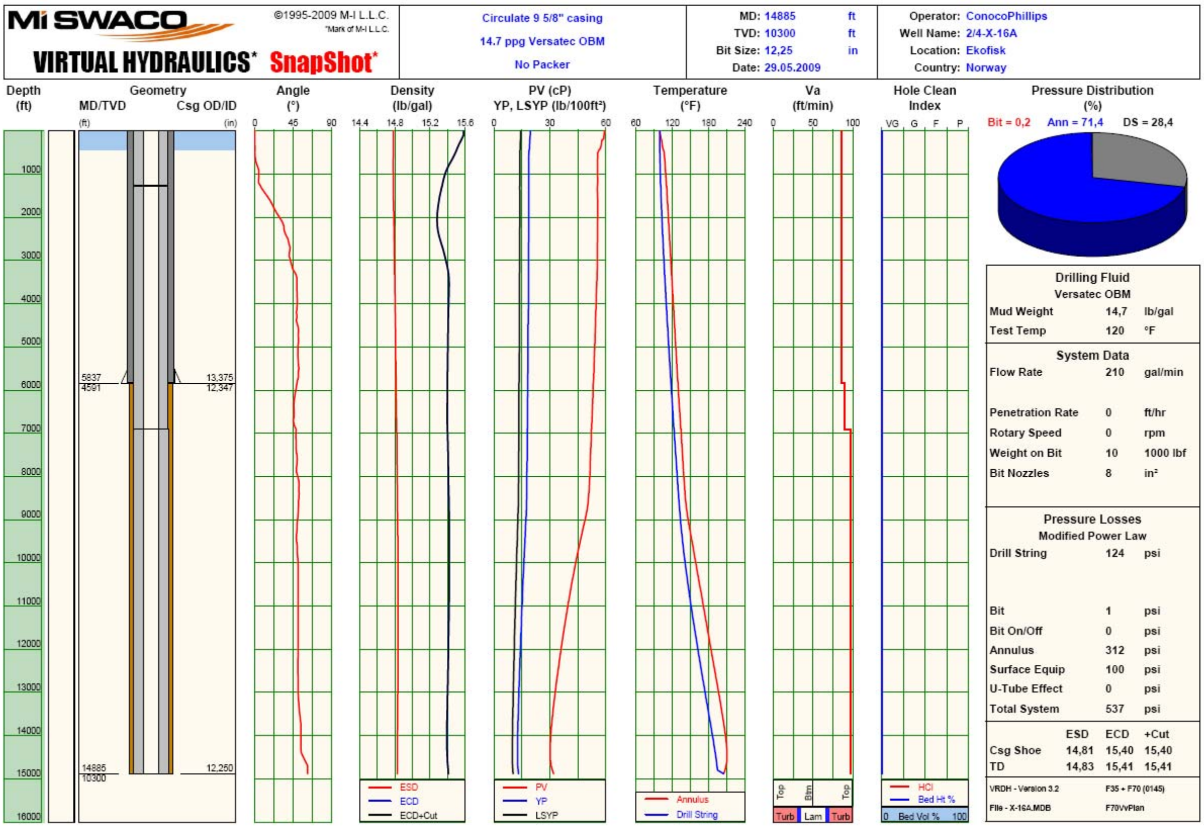


Figure C-0-3 Virtual Hydraulics simulation with Versatec (no packer)

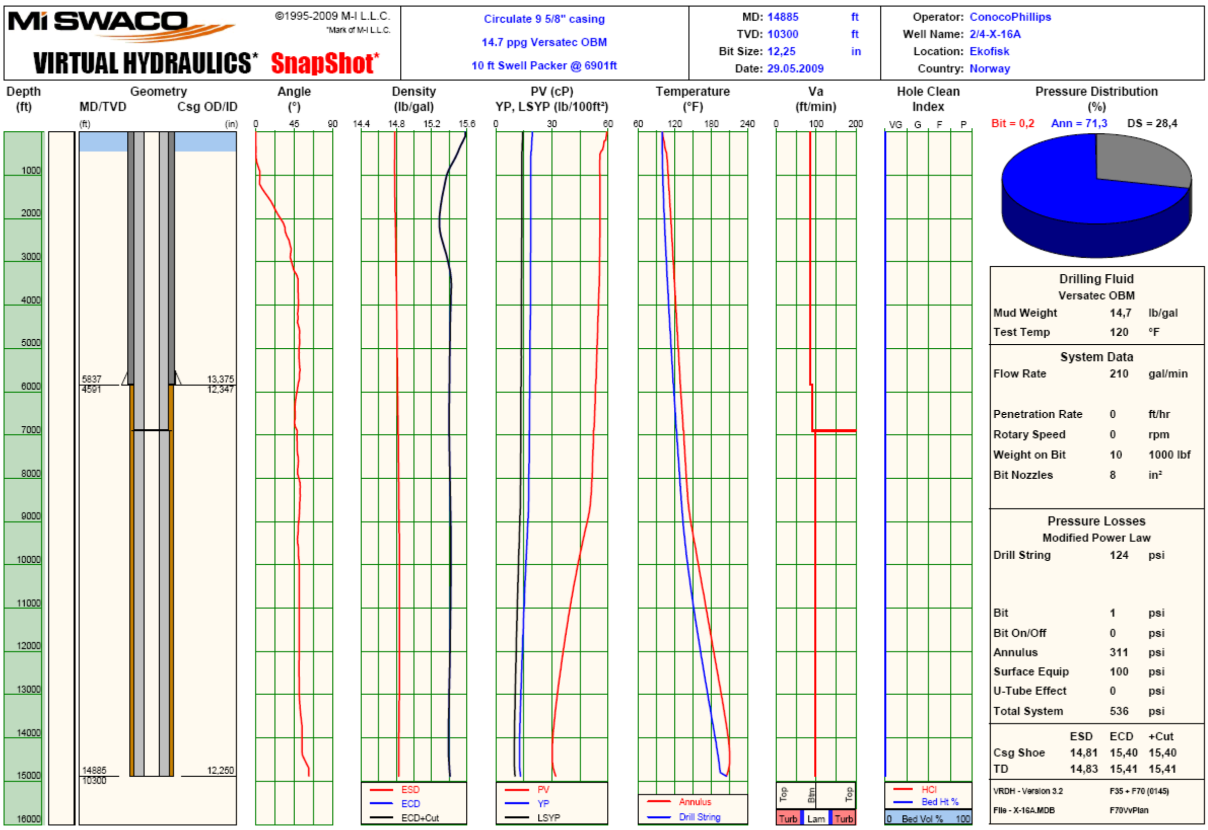
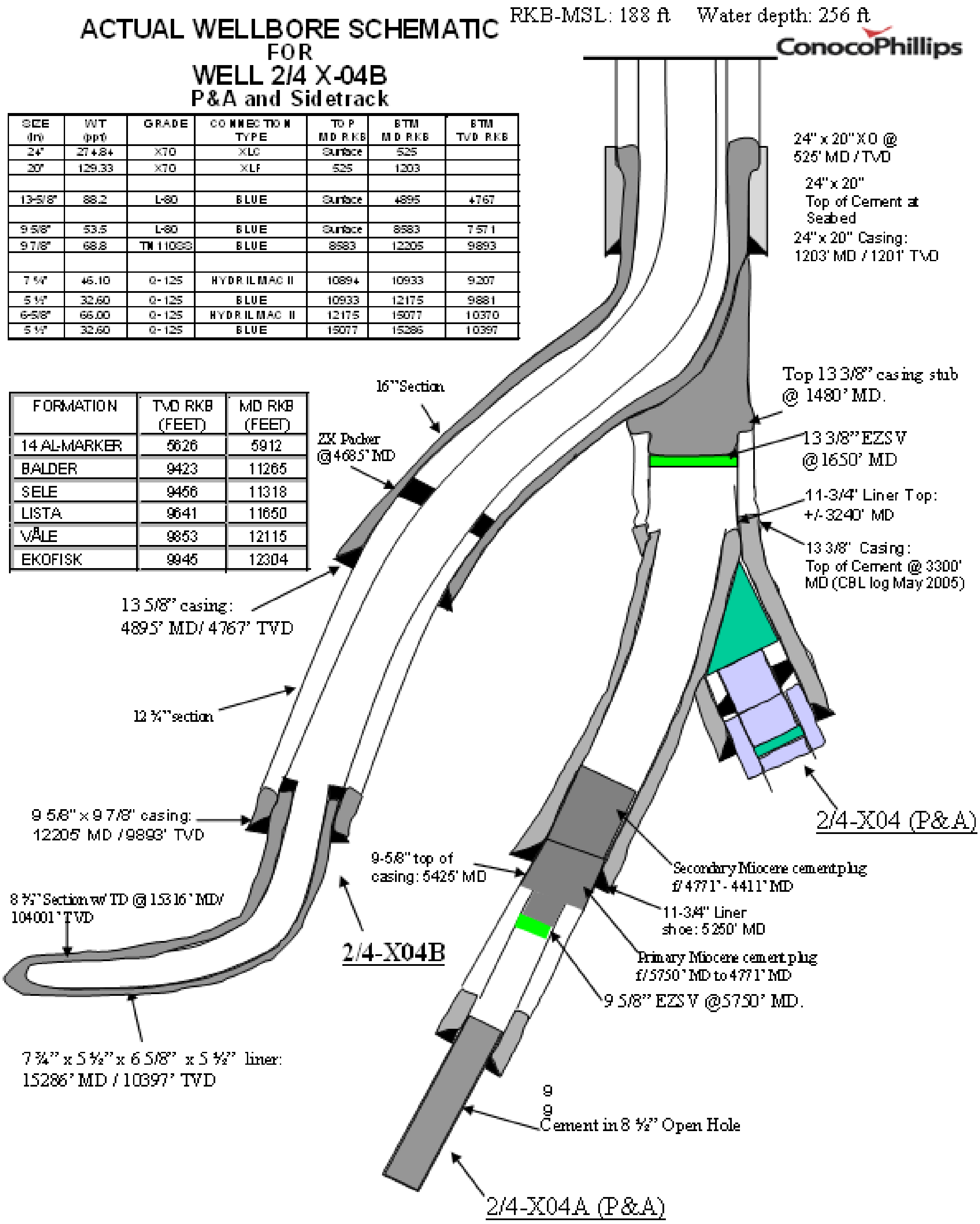


Figure C-0-4 Virtual Hydraulics simulation with Versatec (Swellpacker)

Appendix D CemFacts ECD simulations with light weight cement

Well Schematic



SIZE (in)	WT (ppf)	GRADE	CONNECTION TYPE	TOP MD RKB	BTM MD RKB	BTM TVD RKB
24"	274.84	X70	XLC	Surface	525	
20"	129.33	X70	XLF	525	1203	
13-5/8"	88.2	L-80	BLUE	Surface	4895	4767
9 5/8"	53.5	L-80	BLUE	Surface	8583	7571
9 7/8"	68.8	TN 110SS	BLUE	8583	12205	9893
7 ¾"	46.10	Q-125	HYDRIL MAC II	10894	10933	9207
5 ½"	32.60	Q-125	BLUE	10933	12175	9881
6-5/8"	66.00	Q-125	HYDRIL MAC II	12175	15077	10370
5 ½"	32.60	Q-125	BLUE	15077	15286	10397

FORMATION	TVD RKB (FEET)	MD RKB (FEET)
14 AL-MARKER	5626	5912
BALDER	9423	11265
SELE	9456	11318
LISTA	9641	11650
VÅLE	9853	12115
EKOFISK	9945	12304

Figure D-0-1 Well schematic 2/4-X04B

Warp OBM Rheological Correlation

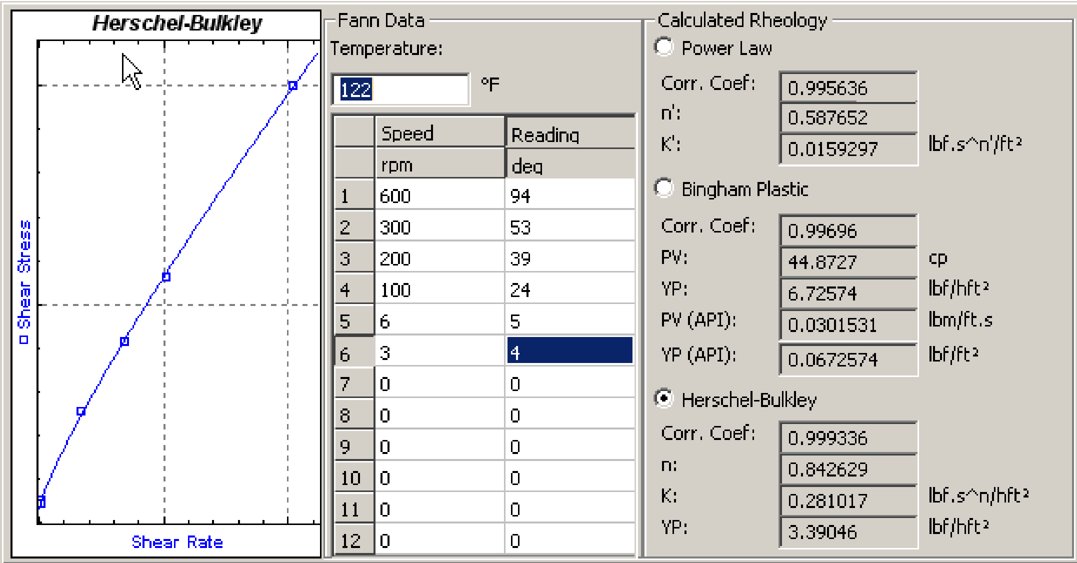


Figure D-0-2 Herschel-Bulkley Warp OBM

Versatec OBM Rheological Correlation

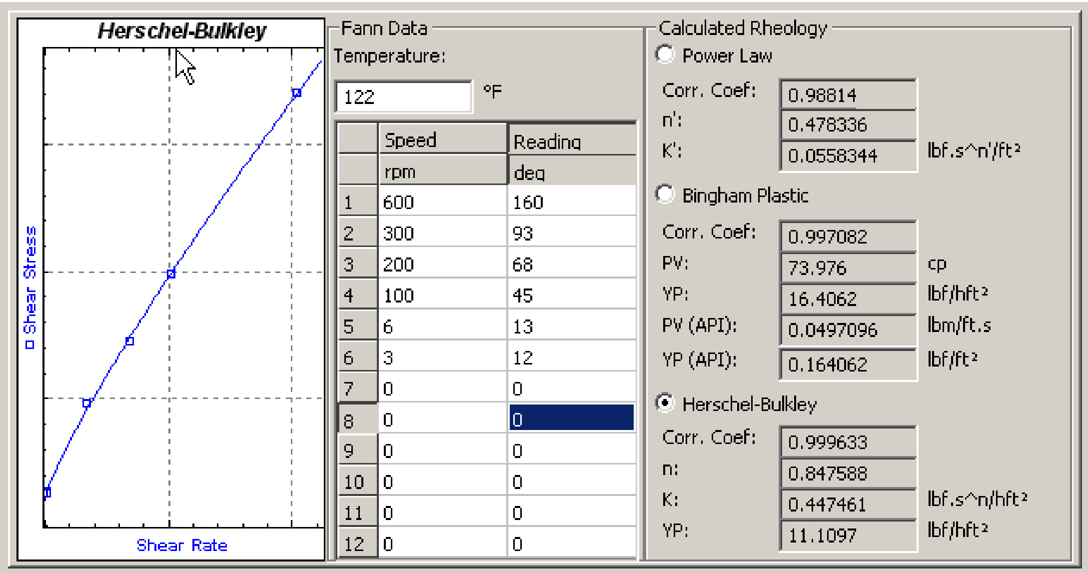


Figure D-0-3 Herschel-Bulkley Versatec OBM

Fluid Location

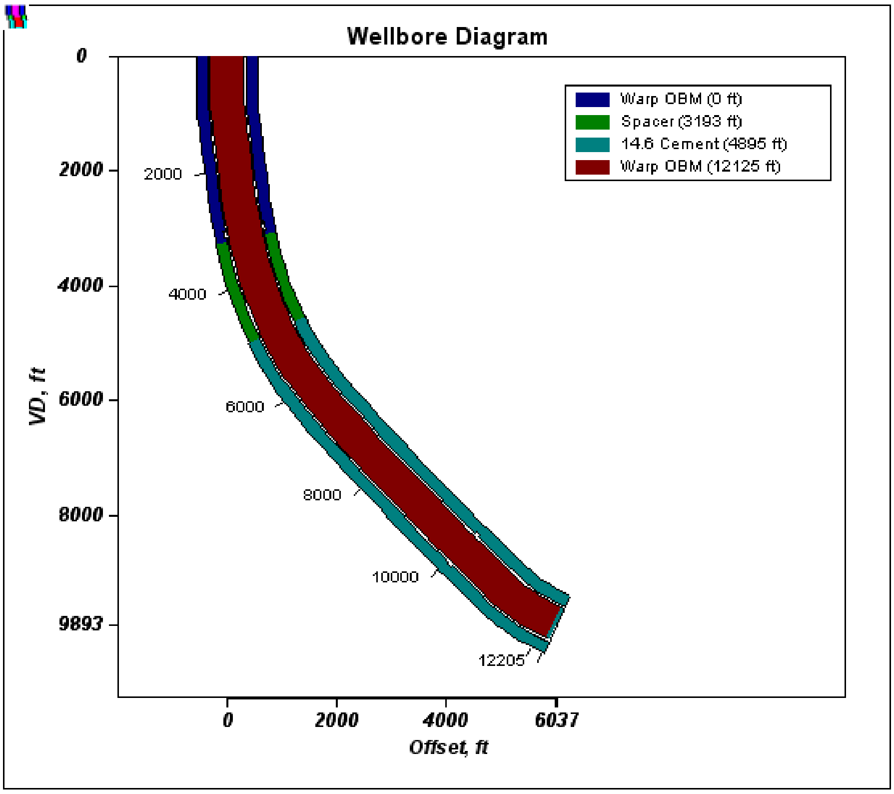


Figure D-0-4 Fluid Location Warp

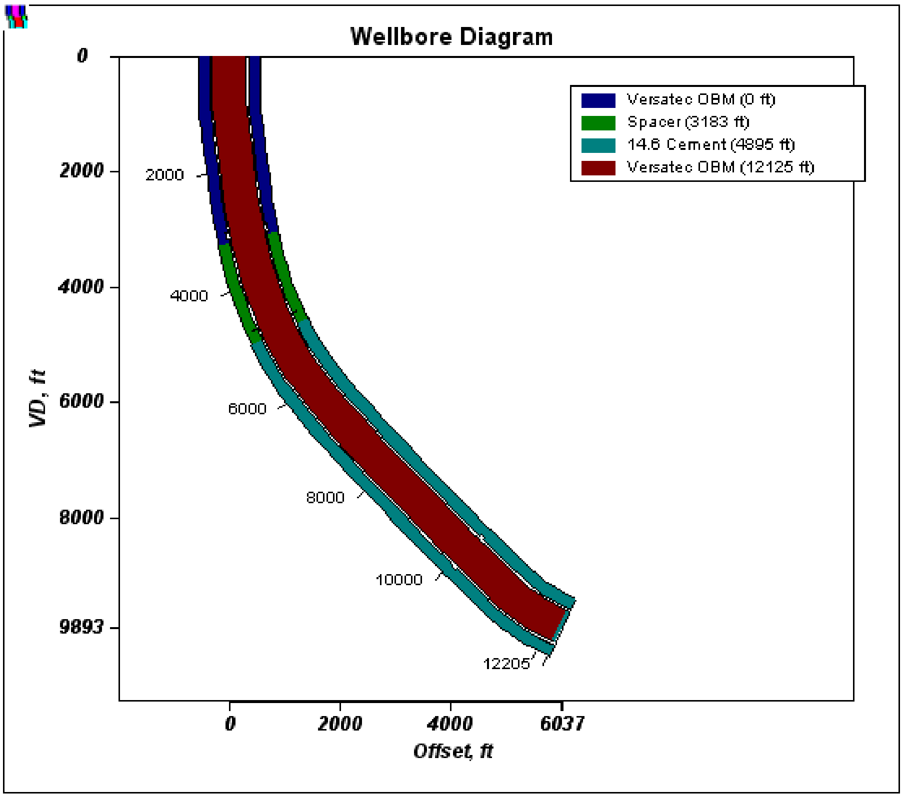


Figure D-0-5 Fluid Location Versatec

CASE 1: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD)

Warp OBM only circulating at 6 BPM

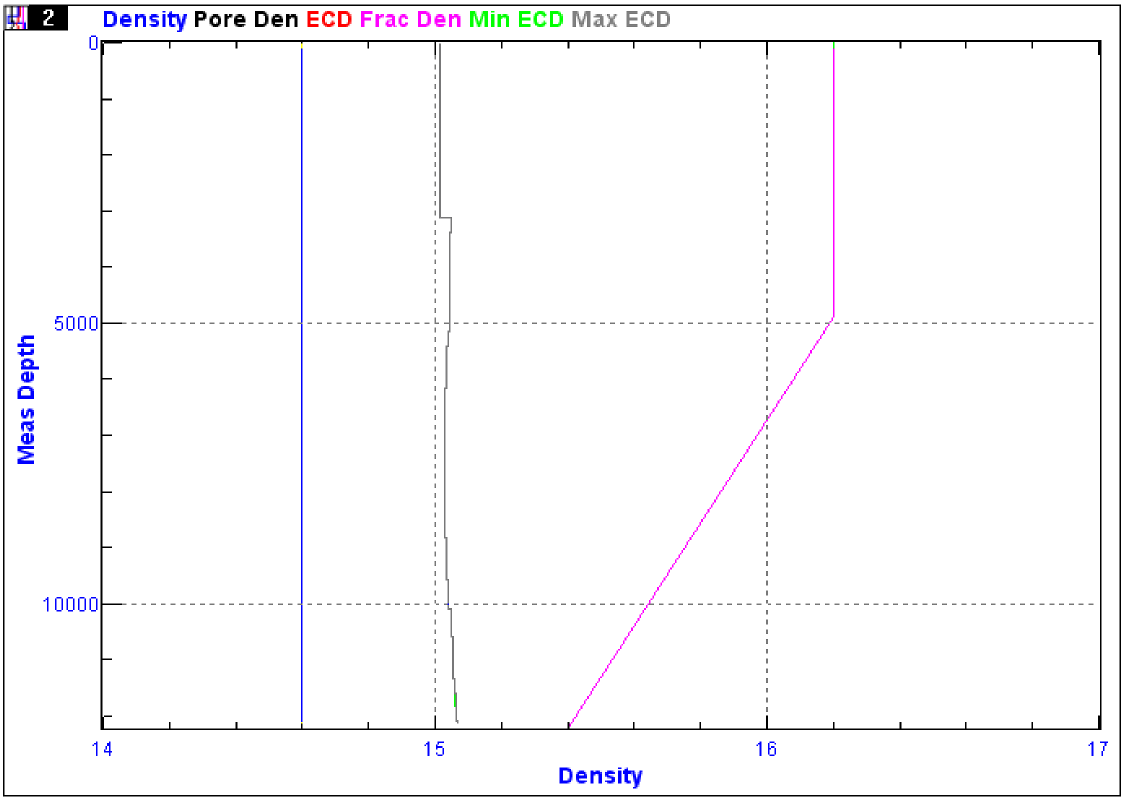


Figure D-0-6 ECD compared with the fracture gradient when circulating Warp OBM at 6BPM

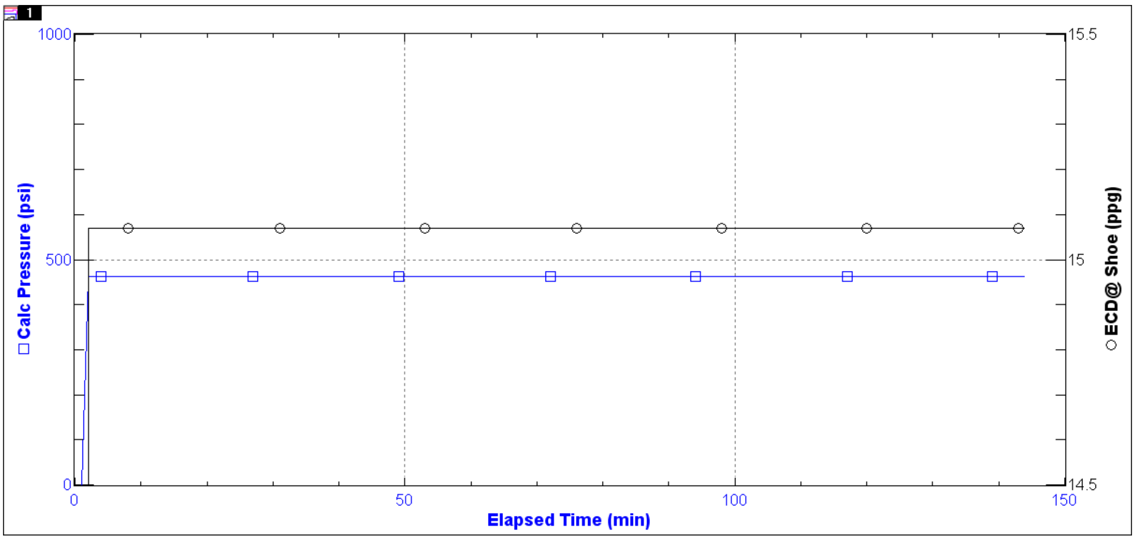


Figure D-0-7 Circulating pressure and ECD at shoe when circulating Warp OBM at 6BPM

CASE 2: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD)

Warp OBM only with Baker ZX Packer at 4685 ft MD, circulating at 6 BPM

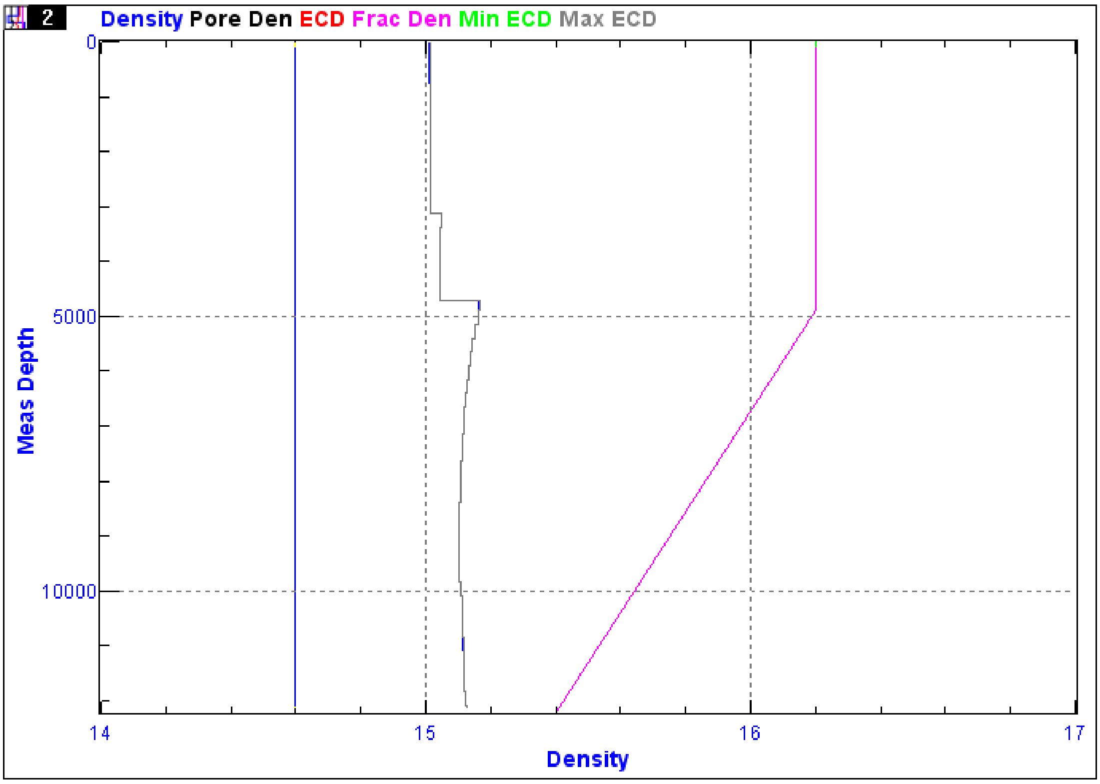


Figure D-0-8 ECD compared with the fracture gradient when circulating Warp OBM at 6 BPM with Baker ZX Packer

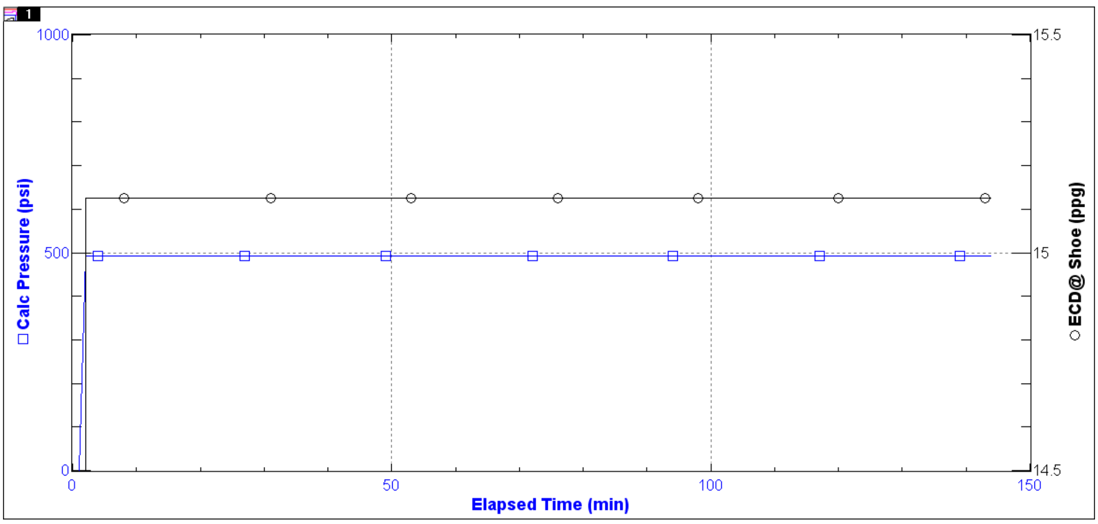


Figure D-0-9 Circulating pressure and ECD at shoe when circulating Warp OBM at 6 BPM with Baker ZX Packer

CASE 3: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD)

Warp OBM only with HETS Expandable Casing at 4685 ft MD, circulating at 6 BPM

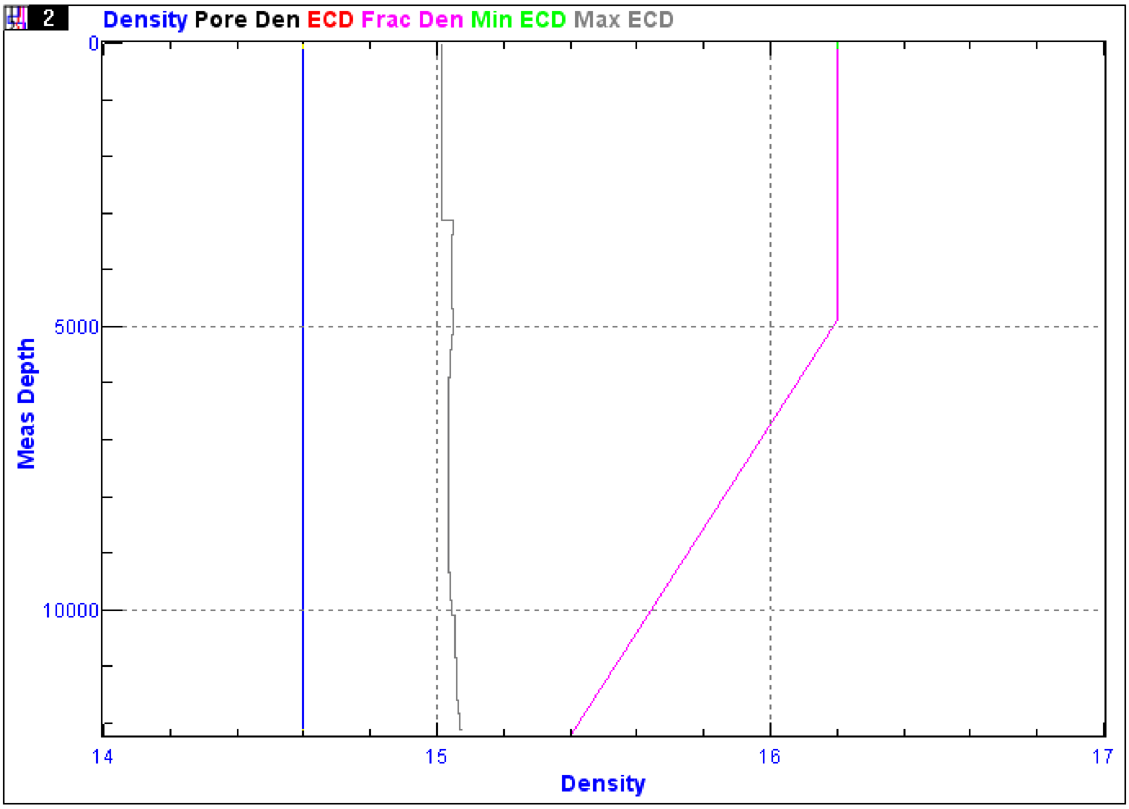


Figure D-0-10 ECD compared with the fracture gradient when circulating Warp OBM at 6 BPM with HETS Expandable casing

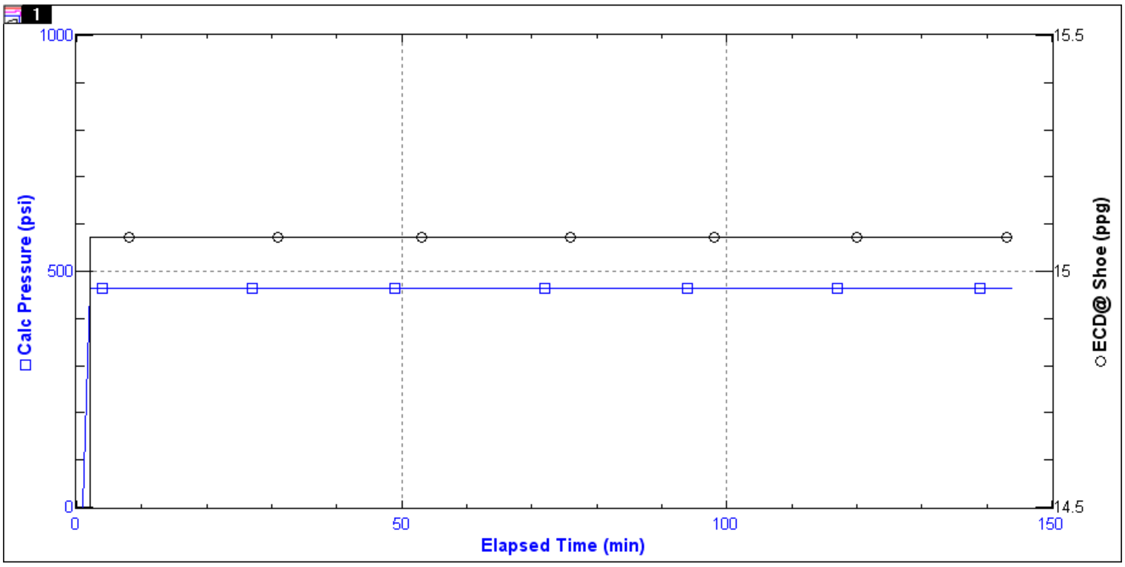


Figure D-0-11 Circulating pressure and ECD at shoe when circulating Warp OBM at 6 BPM with HETS Expandable casing

CASE 4: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD)

Versatec OBM only circulating at 6 BPM

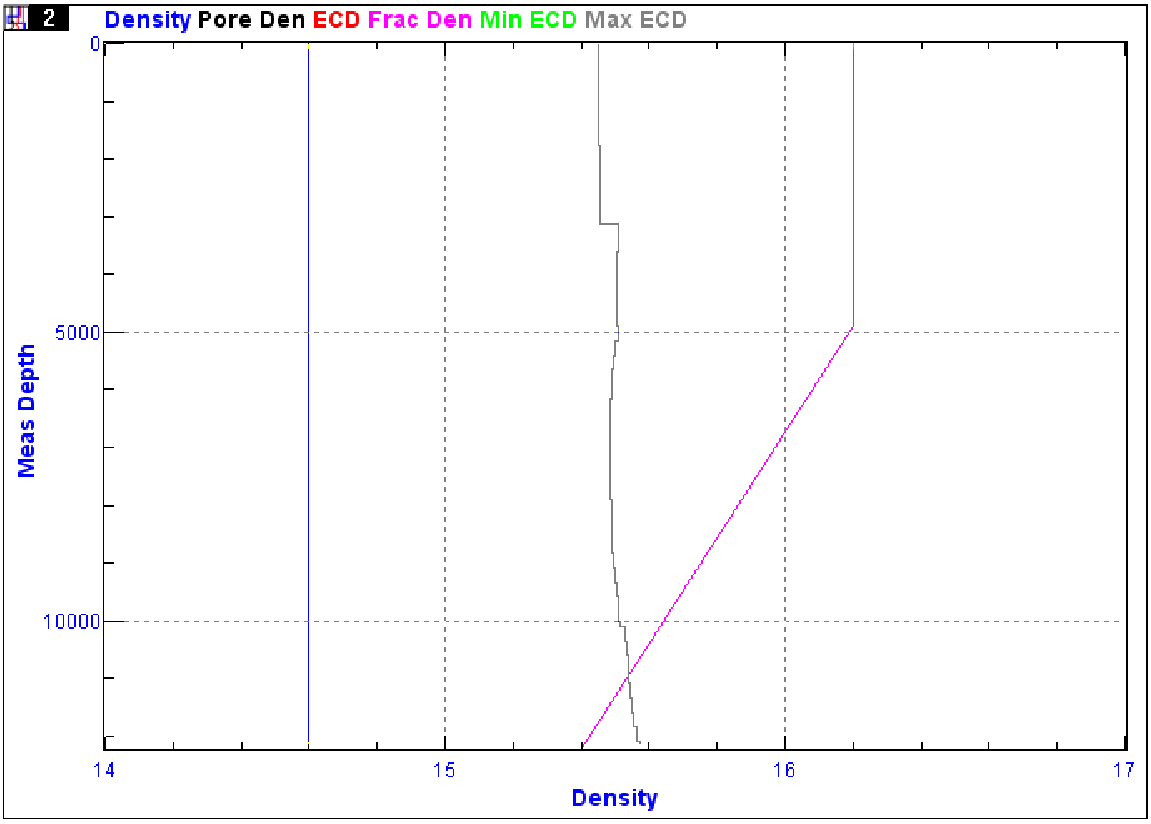


Figure D-0-12 ECD compared with the fracture gradient when circulating Versatec OBM at 6BPM

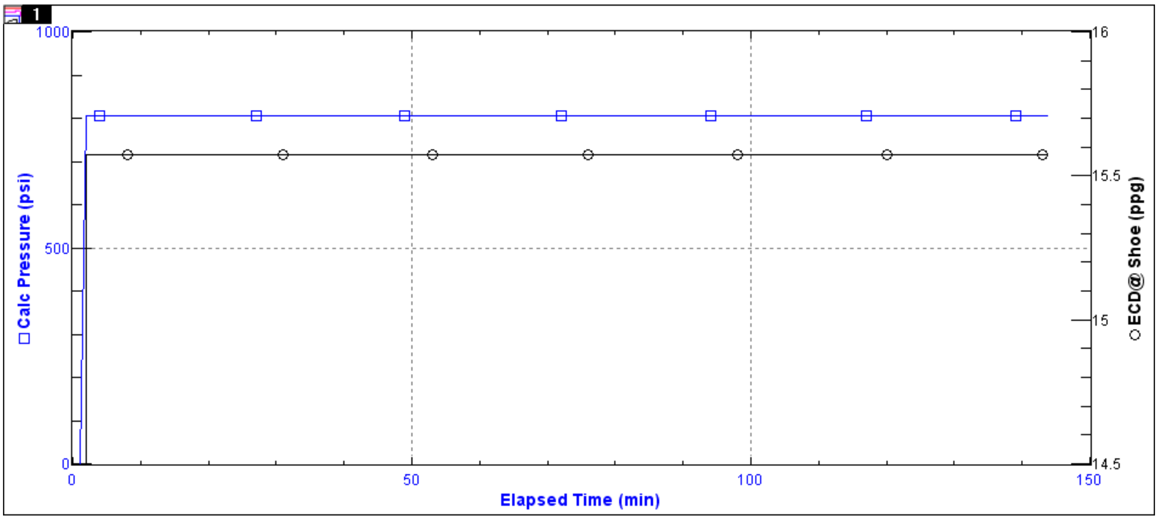


Figure D-0-13 Circulating pressure and ECD at shoe when circulating Versatec OBM at 6 BPM

CASE 5: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD)

Versatec OBM only with Baker ZX Packer at 4685 ft MD, circulating at 6 BPM

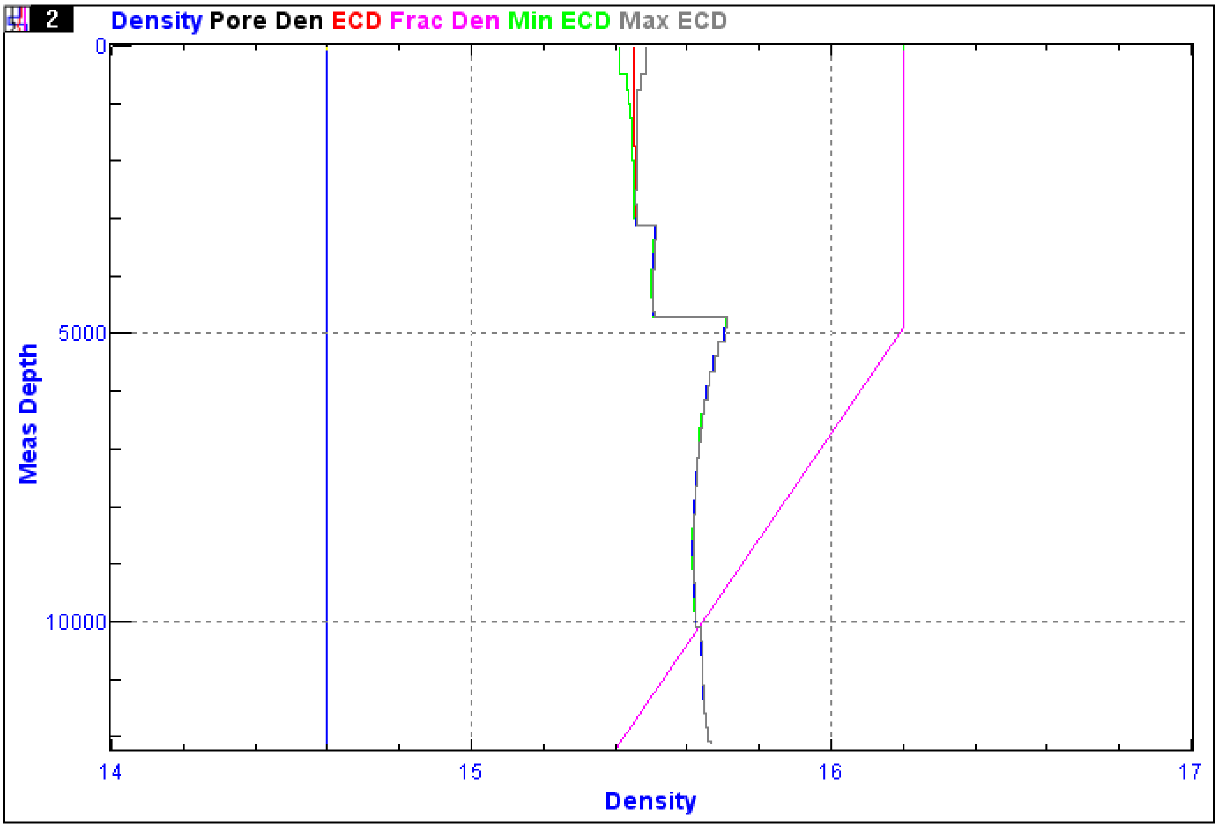


Figure D-0-14 ECD compared with the fracture gradient when circulating Versatec OBM at 6 BPM with Baker ZX Packer

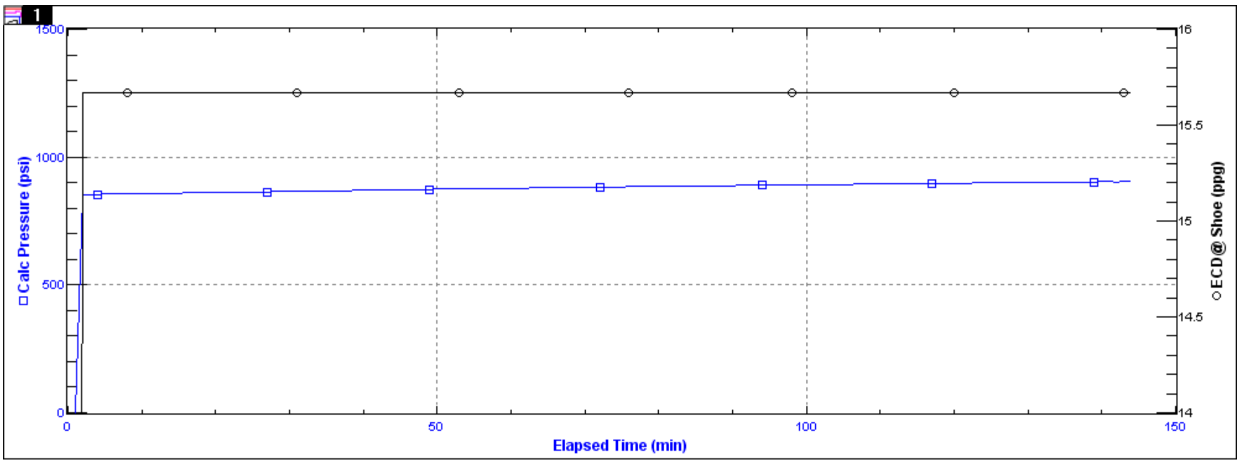


Figure D-0-15 Circulating pressure and ECD at shoe when circulating Versatec OBM at 6 BPM with Baker ZX Packer

CASE 6: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD)

Versatec OBM only with HETS Exp. Casing at 4685 ft MD, circulating at 6 BPM

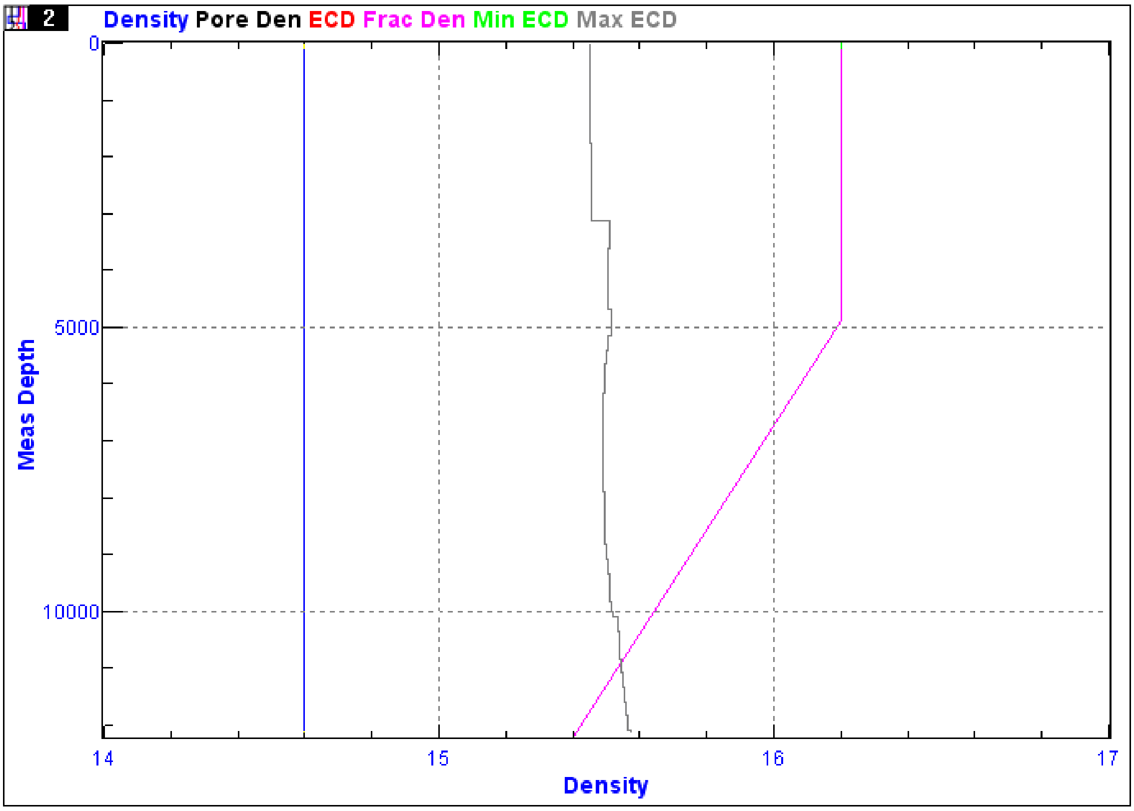


Figure D-0-16 ECD compared with the fracture gradient when circulating Versatec OBM at 6 BPM with HETS Expandable casing

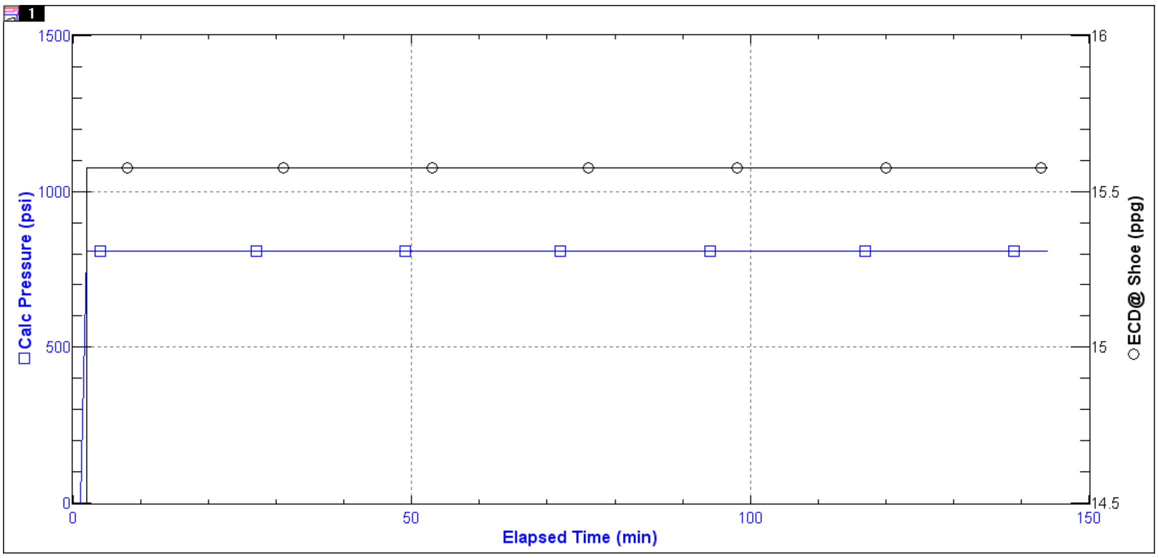


Figure D-0-17 Circulating pressure and ECD at shoe when circulating Versatec OBM at 6 BPM with HETS Expandable Packer

CASE 7: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD)

Cement, Spacer and Warp OBM mixing/pumping at 5 BPM

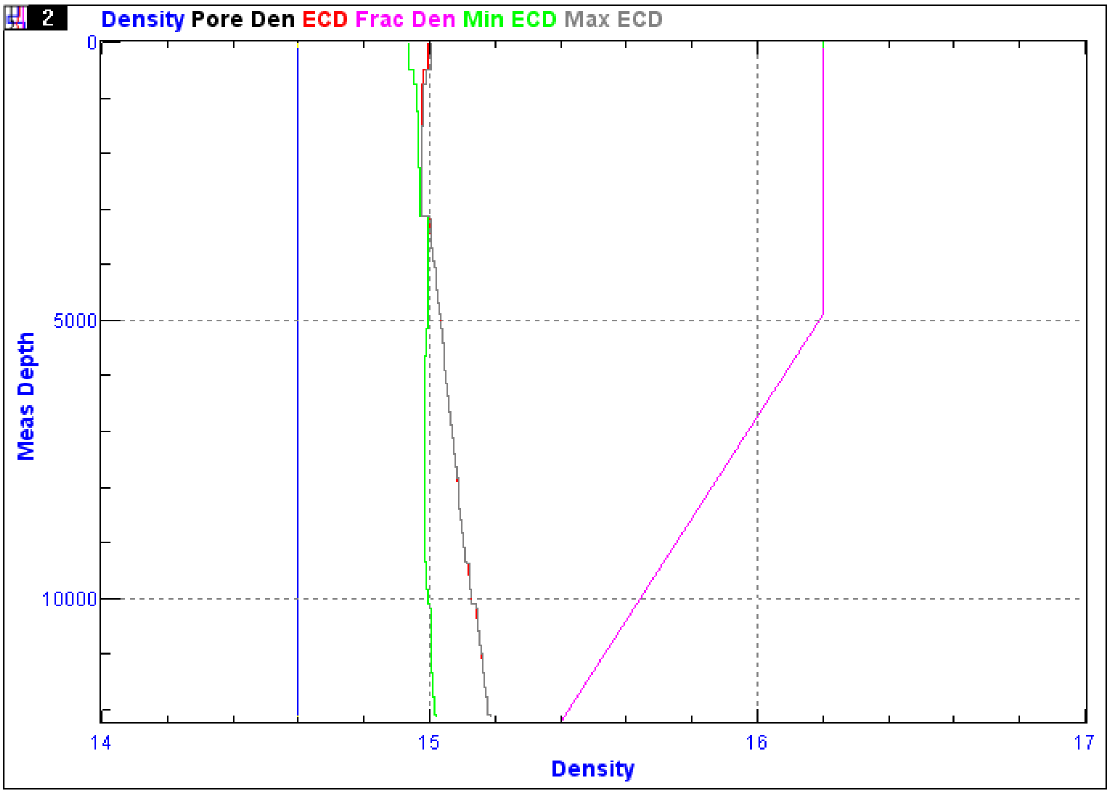


Figure D-0-18 ECD compared with the fracture gradient when circulating cement, spacer and Warp OBM at 5BPM

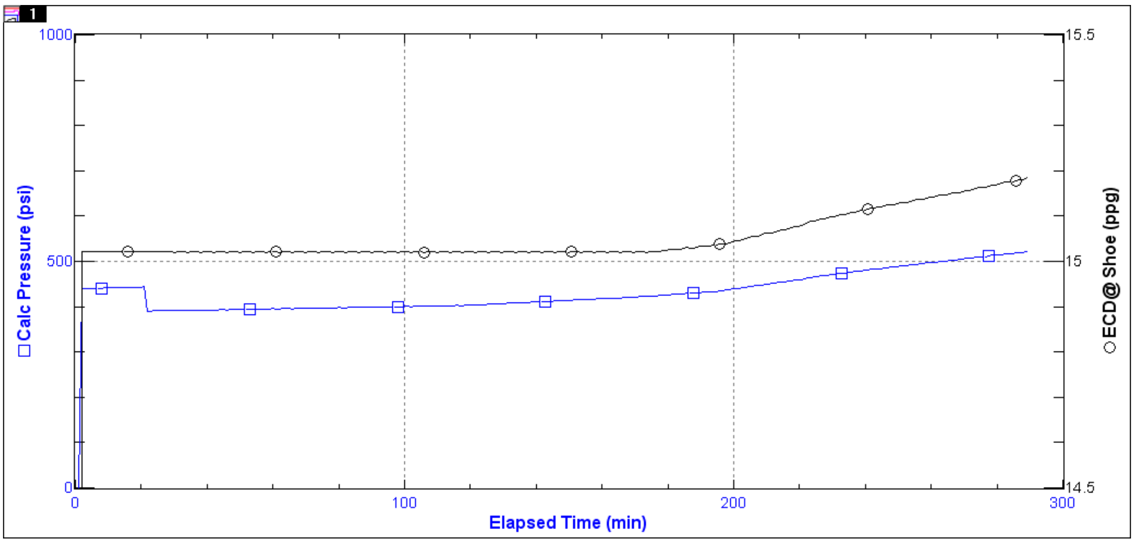


Figure D-0-19 Circulating pressure and ECD at shoe when circulating cement, spacer and Warp OBM at 5BPM

CASE 8: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD) with Baker ZX Packer at 4685 ft MD

Cement, Spacer and Warp OBM mixing/pumping at 5 BPM

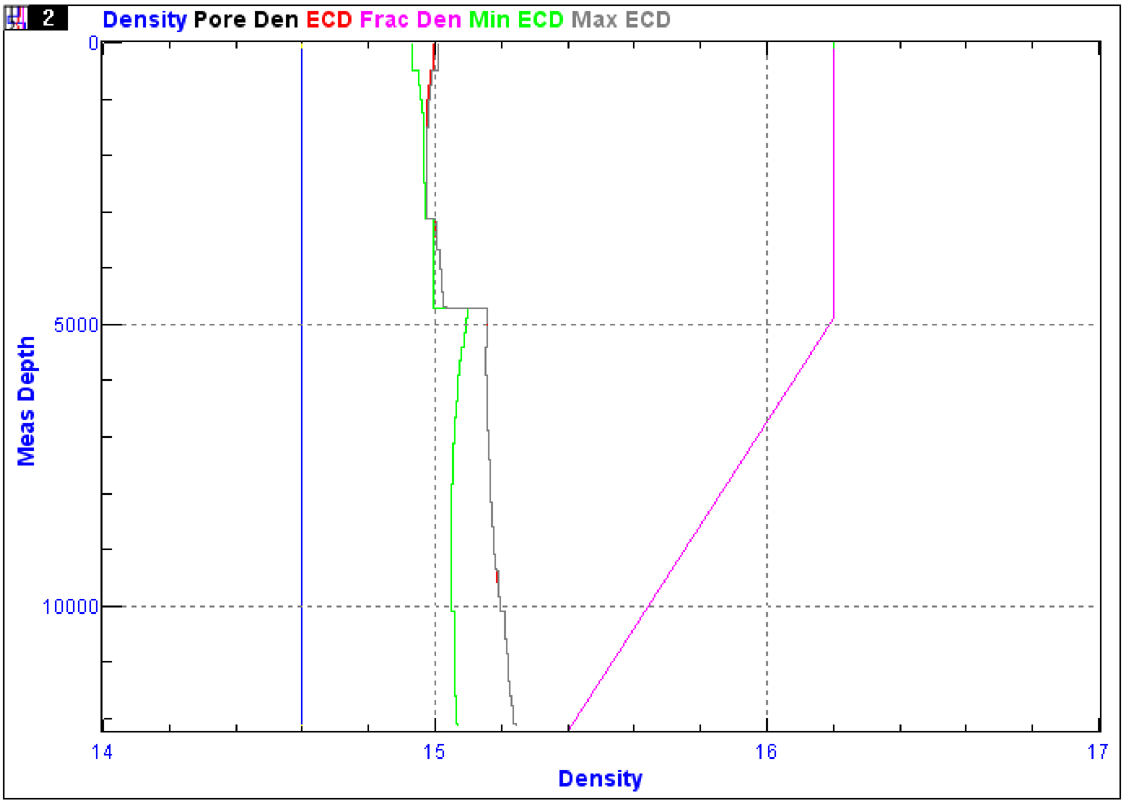


Figure D-0-20 ECD compared with the fracture gradient when circulating cement, spacer and Warp OBM at 5BPM with Baker ZX Packer

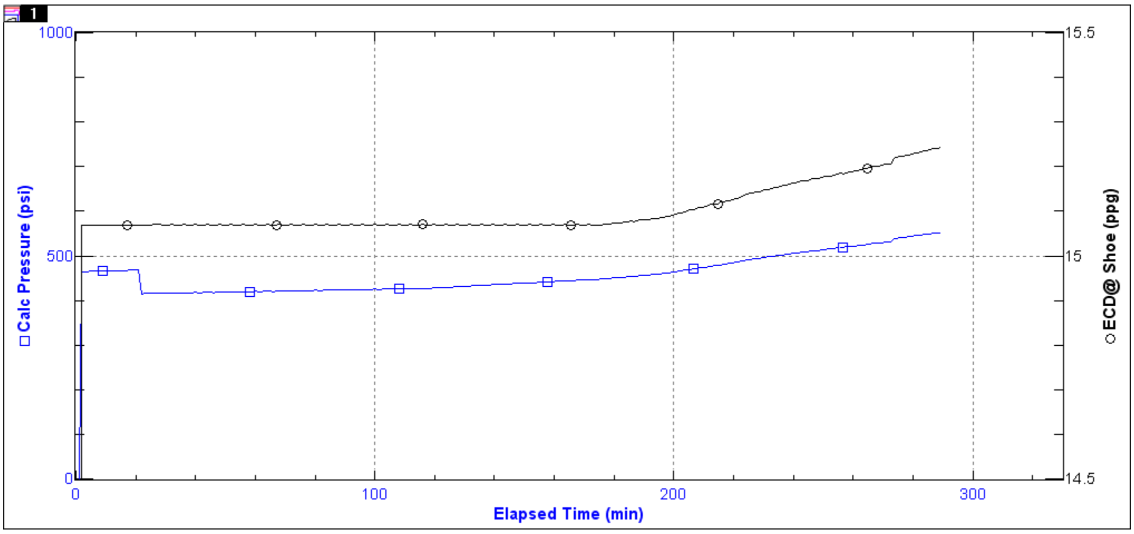


Figure D-0-21 Circulating pressure and ECD at shoe when circulating cement, spacer and Warp OBM at 5BPM with Baker ZX Packer

CASE 9: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD) with HETS Exp. Casing at 4685 ft MD

Cement, Spacer and Warp OBM mixing/pumping at 5 BPM

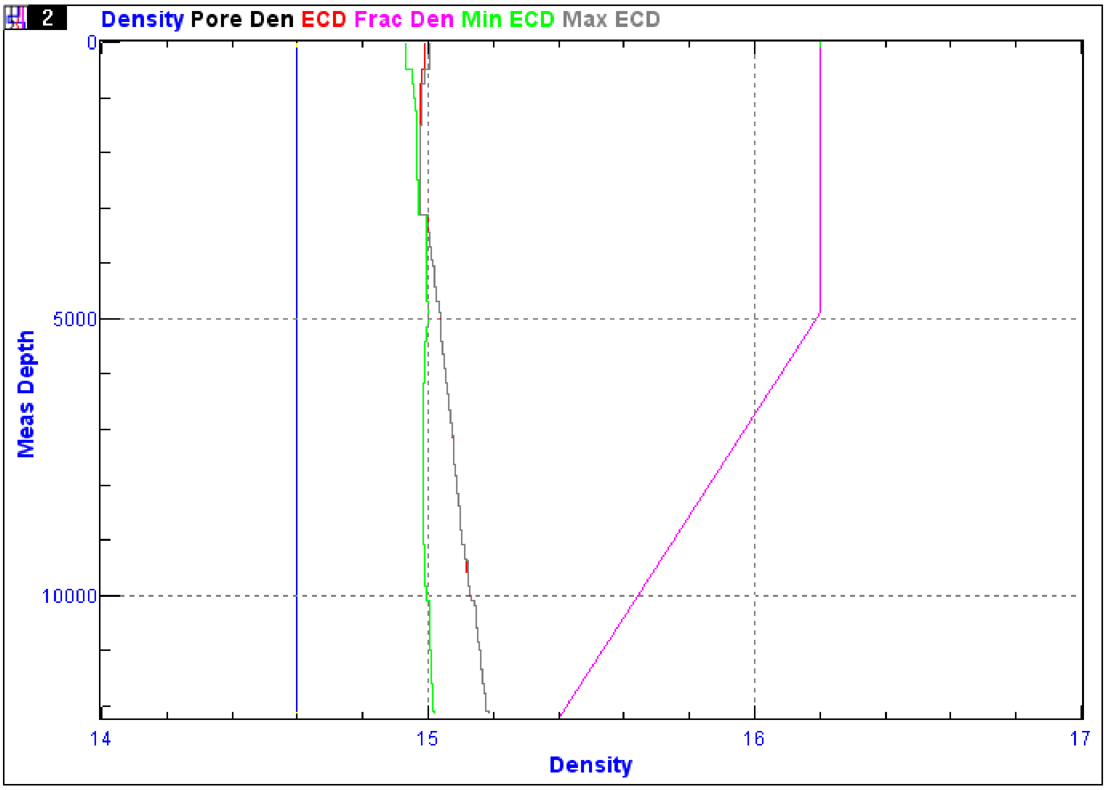


Figure D-0-22 ECD compared with the fracture gradient when circulating cement, spacer and Warp OBM at 5BPM with HETS Expandable Casing

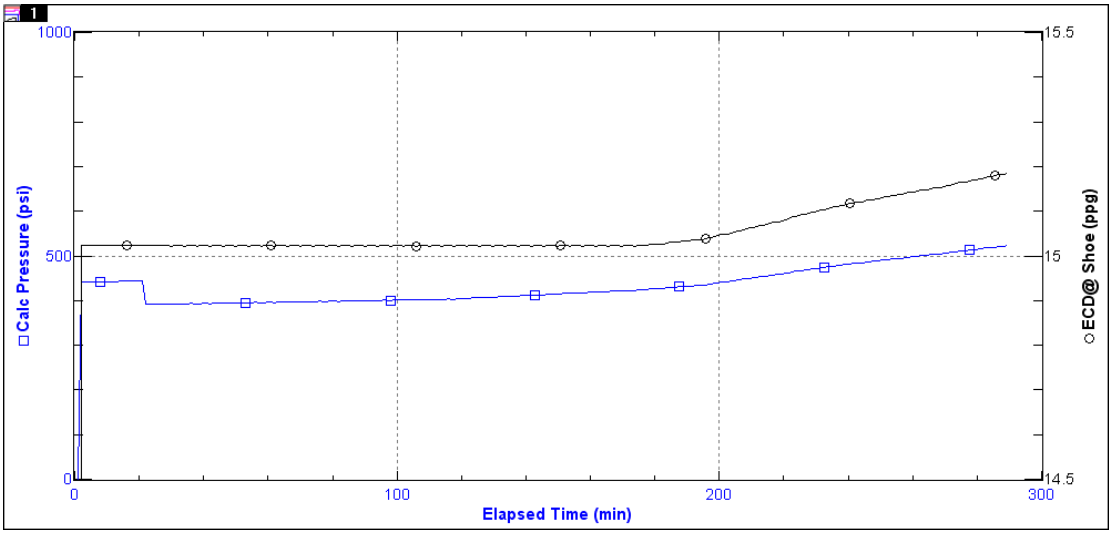


Figure D-0-23 Circulating pressure and ECD at shoe when circulating cement, spacer and Warp OBM at 5BPM with HETS Expandable Casing

Case 10: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD)

Cement, Spacer and Versatec OBM mixing/pumping at 5 BPM

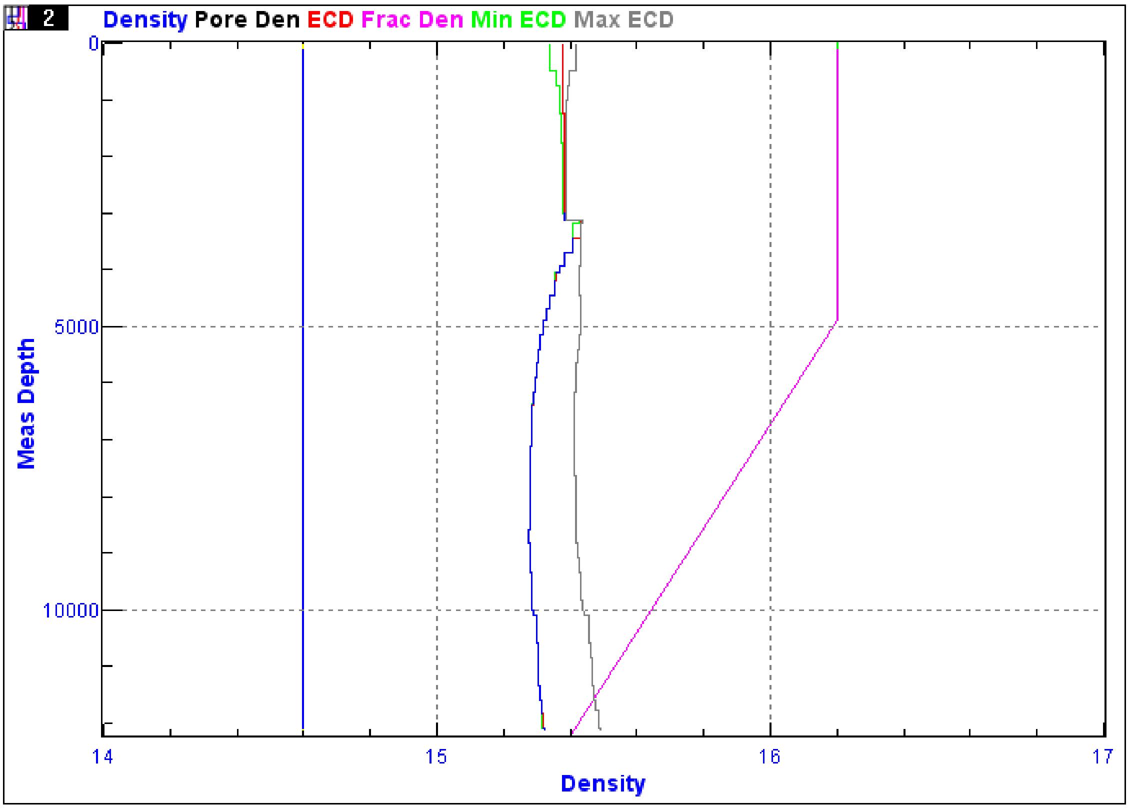


Figure D-0-24 ECD compared with the fracture gradient when circulating cement, spacer and Versatec OBM at 5BPM

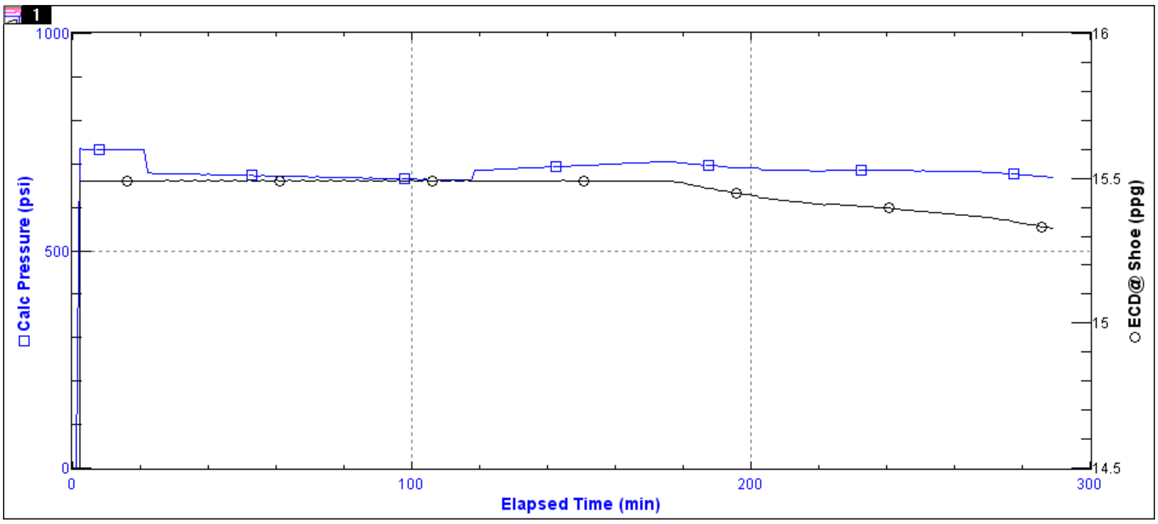


Figure D-0-25 Circulating pressure and ECD at shoe when circulating cement, spacer and Versatec OBM at 5BPM

CASE 11: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD) with Baker ZX Packer at 4685 ft MD

Cement, Spacer and Versatec OBM mixing/pumping at 5 BPM

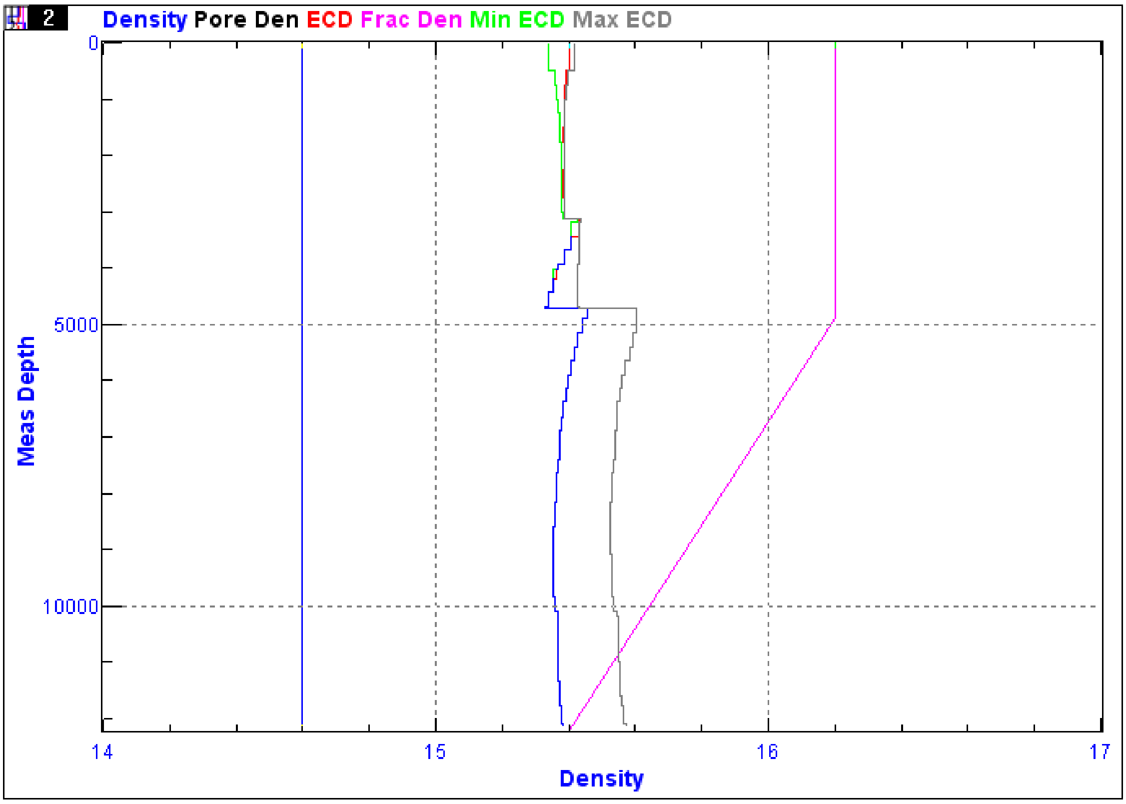


Figure D-0-26 ECD compared with the fracture gradient when circulating cement, spacer and Versatec OBM at 5BPM with Baker ZX Packer

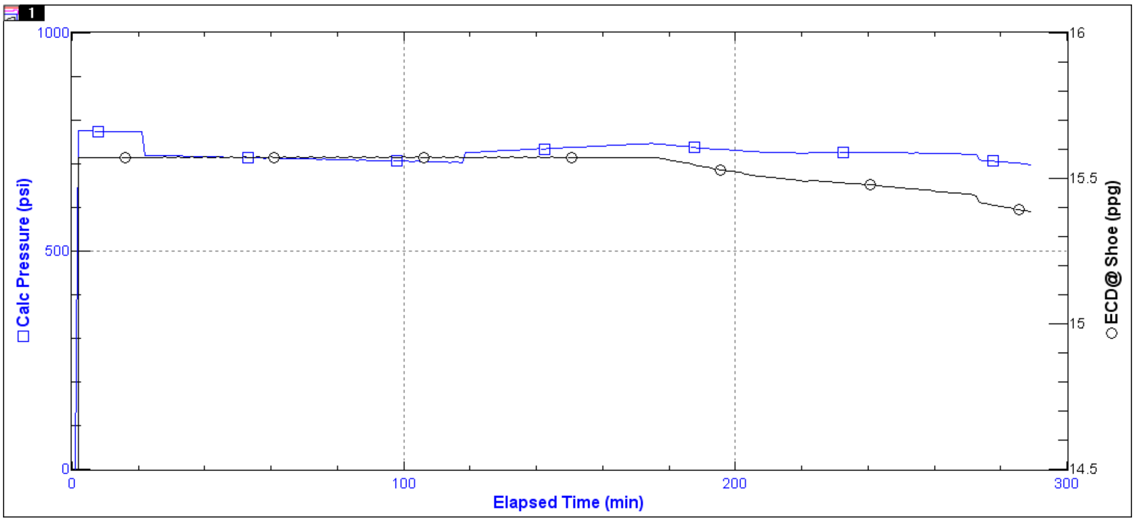


Figure D-0-27 Circulating pressure and ECD at shoe when circulating cement, spacer and Versatec OBM at 5BPM with Baker ZX Packer

CASE 12: Full 9 5/8-in x 9 7/8-in casing string set at 12205 ft MD (9893 ft TVD) with HETS Exp. Casing at 4685 ft MD

Cement, Spacer and Versatec OBM mixing/pumping at 5 BPM

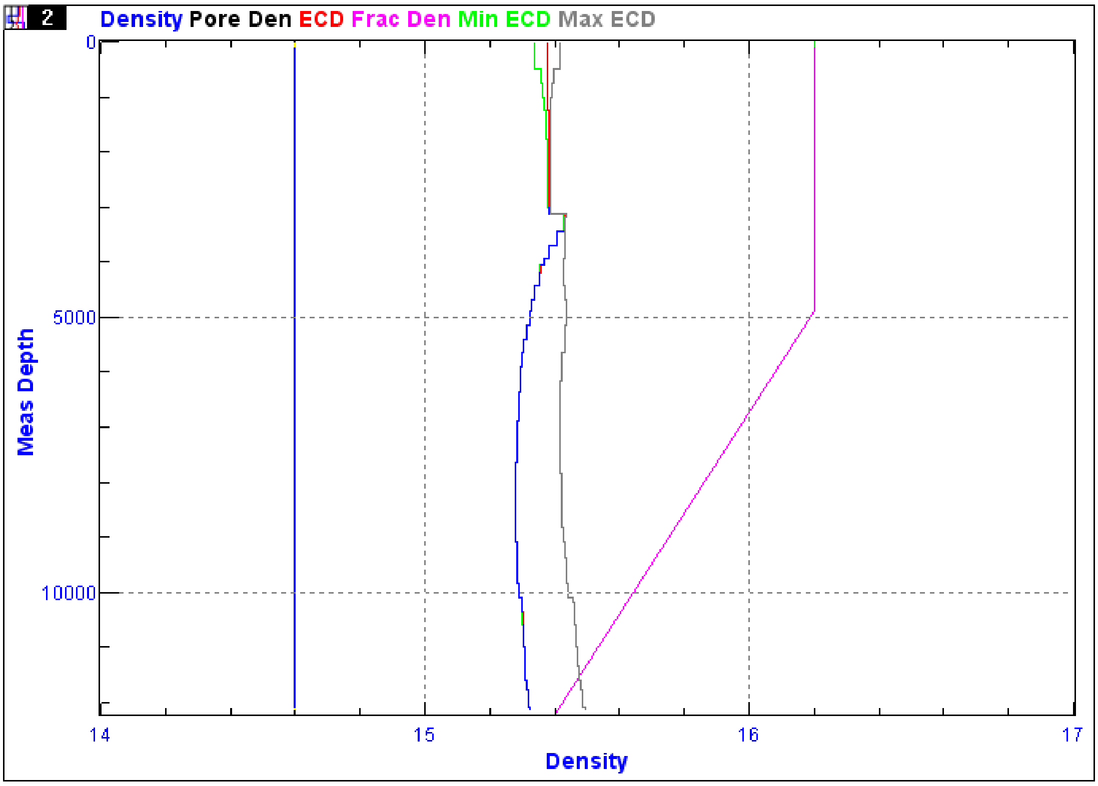


Figure D-0-28 ECD compared with the fracture gradient when circulating cement, spacer and Versatec OBM at 5BPM with HETS Expandable Casing

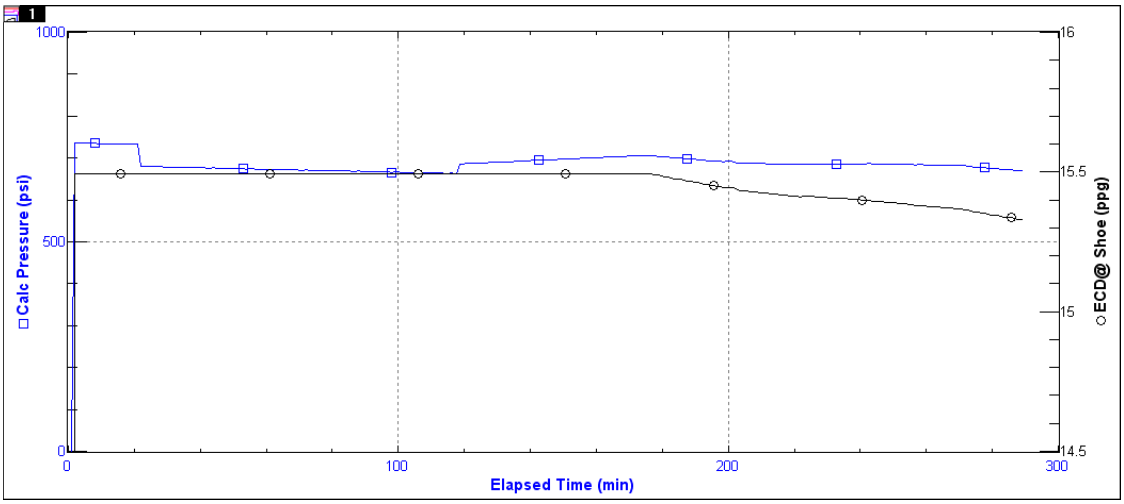


Figure D-0-29 Circulating pressure and ECD at shoe when circulating cement, spacer and Versatec OBM at 5BPM with HETS Expandable Casing

CASE 13: 9 7/8-in liner set at 12205 ft MD (9893 ft TVD)

Warp OBM only with Versaflex LH circulating at 6 BPM

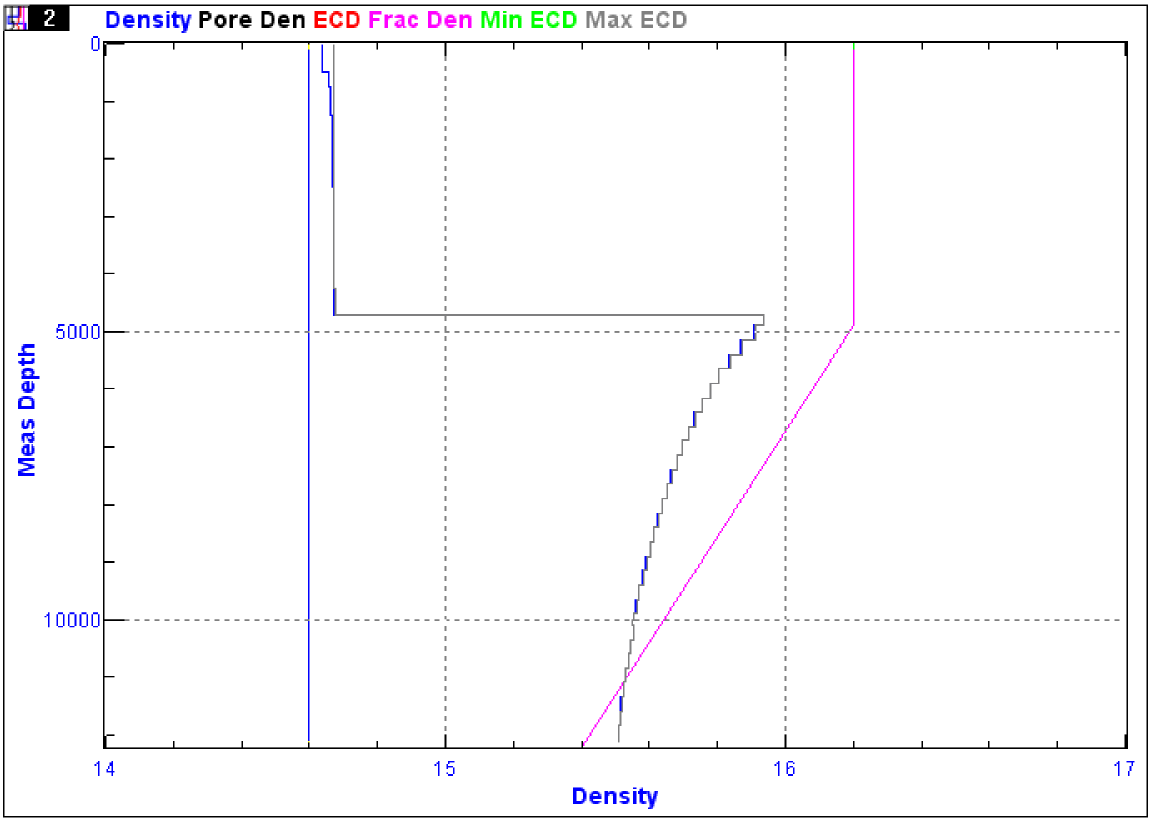
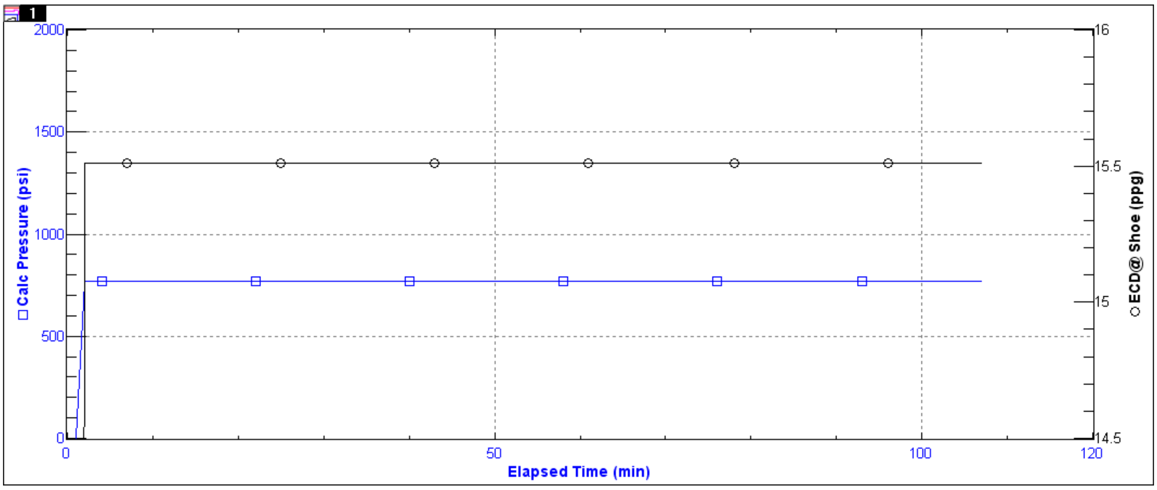


Figure D-0-30 ECD compared with the fracture gradient when circulating Warp OBM at 6BPM with Versaflex LH



FigureD-0-31 Circulating pressure and ECD at shoe when circulating cement Warp OBM at 5BPM with Versaflex LH

CASE 14: 9 7/8-in liner set at 12205 ft MD (9893 ft TVD)

Warp OBM only with Baker ZXP LH circulating at 6 BPM

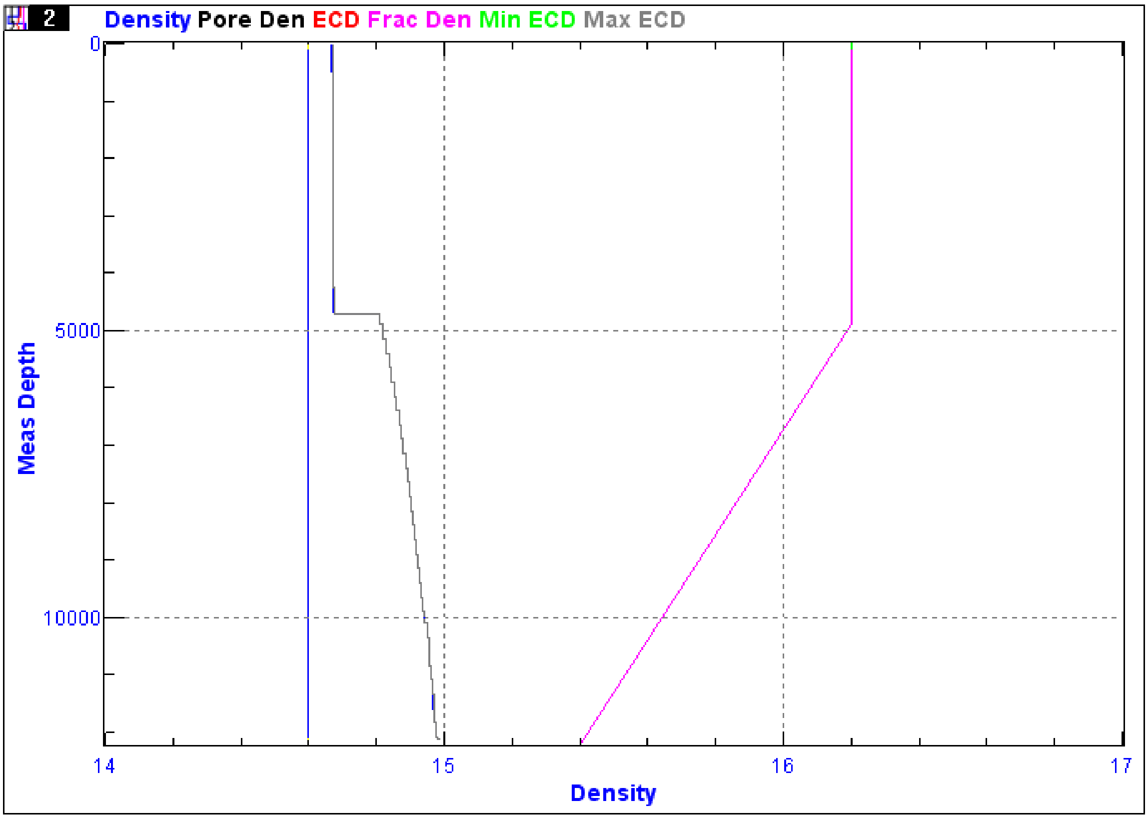


Figure D-0-32 ECD compared with the fracture gradient when circulating Warp OBM at 6BPM with Baker ZXP LH

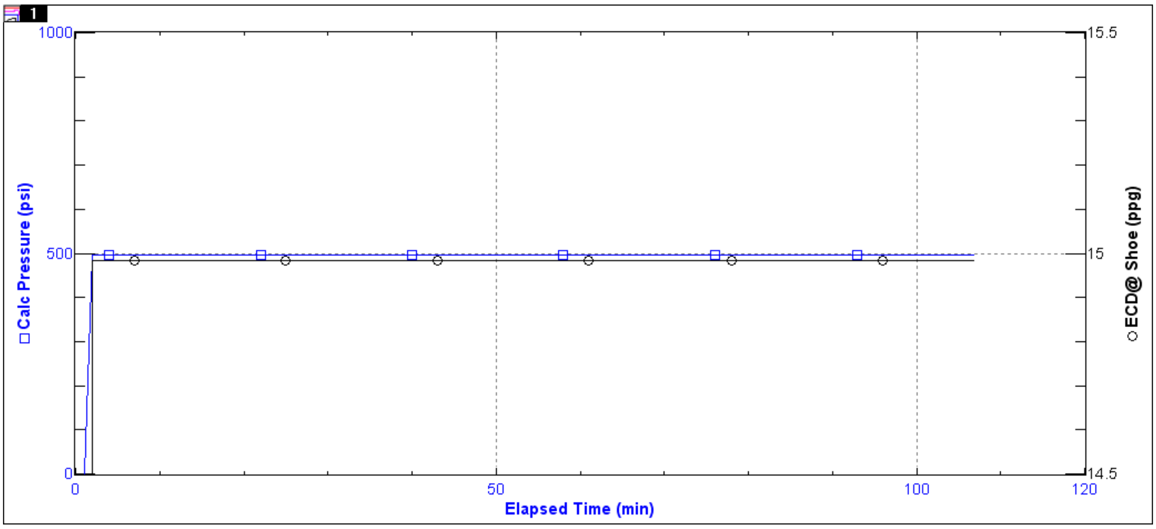


Figure D-0-33 Circulating pressure and ECD at shoe when circulating cement Warp OBM at 6BPM with Baker ZXP LH

CASE 15: 9 7/8-in liner set at 12205 ft MD (9893 ft TVD)

Versatec OBM only with Versaflex LH circulating at 6 BPM

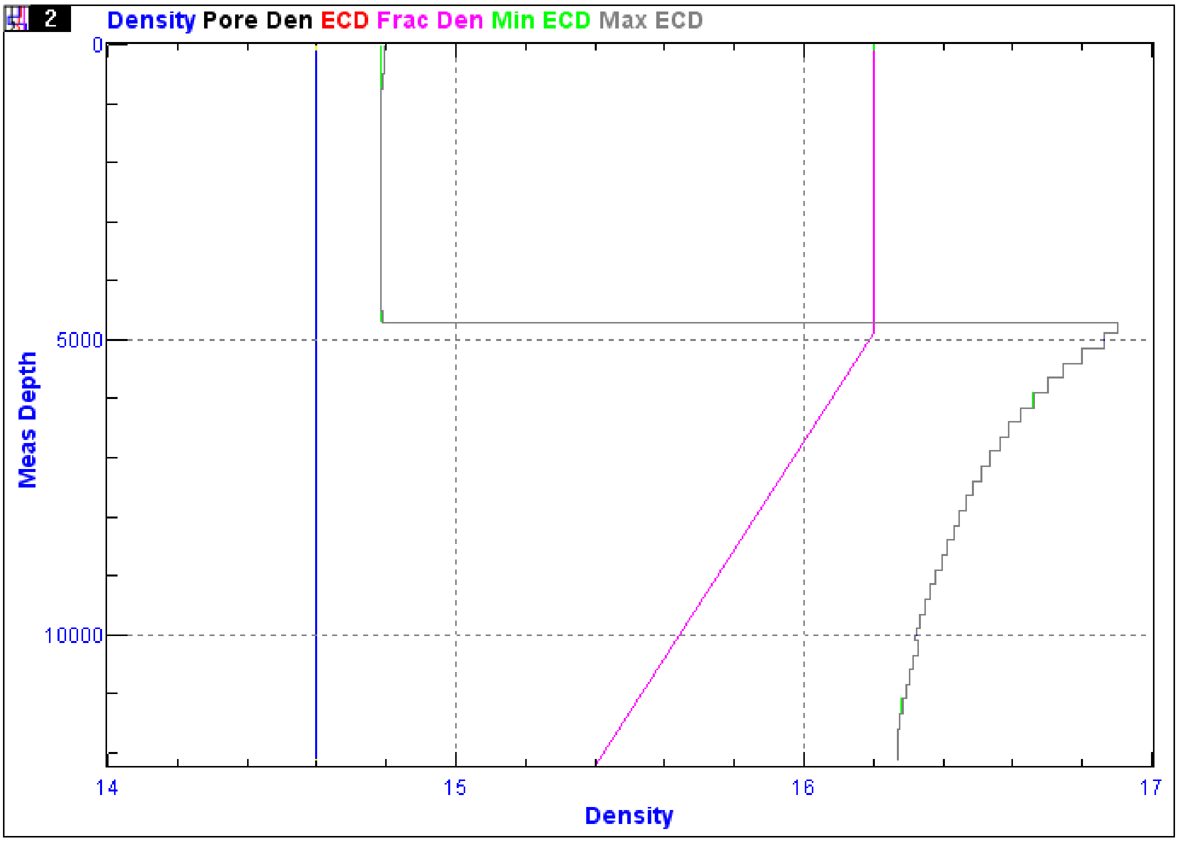


Figure D-0-34 ECD compared with the fracture gradient when circulating Versatec OBM at 6BPM with Versaflex LH

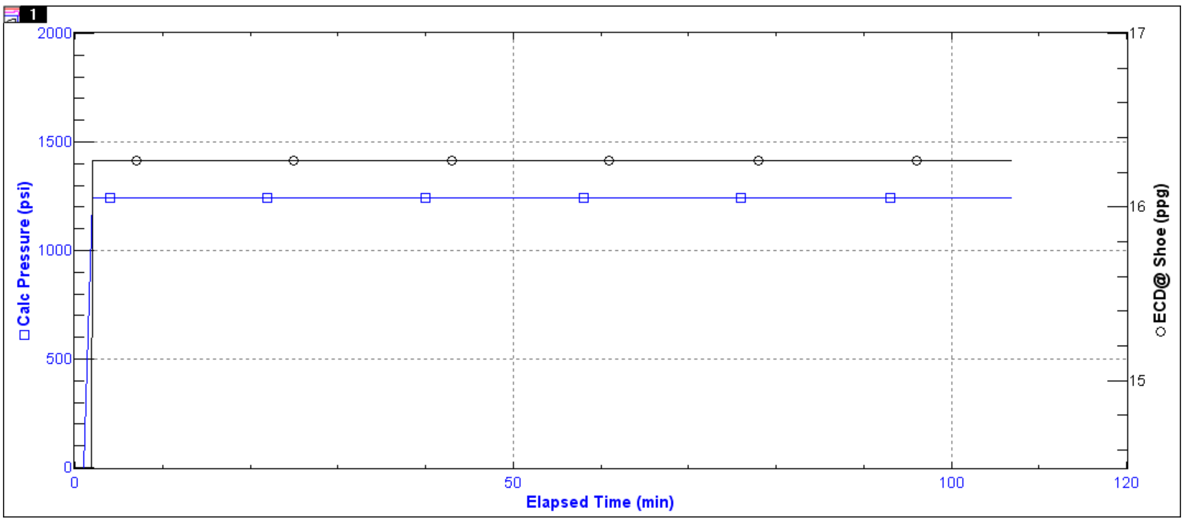


Figure D-0-35 Circulating pressure and ECD at shoe when circulating cement Versatec OBM at 6BPM with Versaflex LH

CASE 16: 9 7/8-in liner set at 12205 ft MD (9893 ft TVD)

Versatec OBM only with Baker ZX LH circulating at 6 BPM

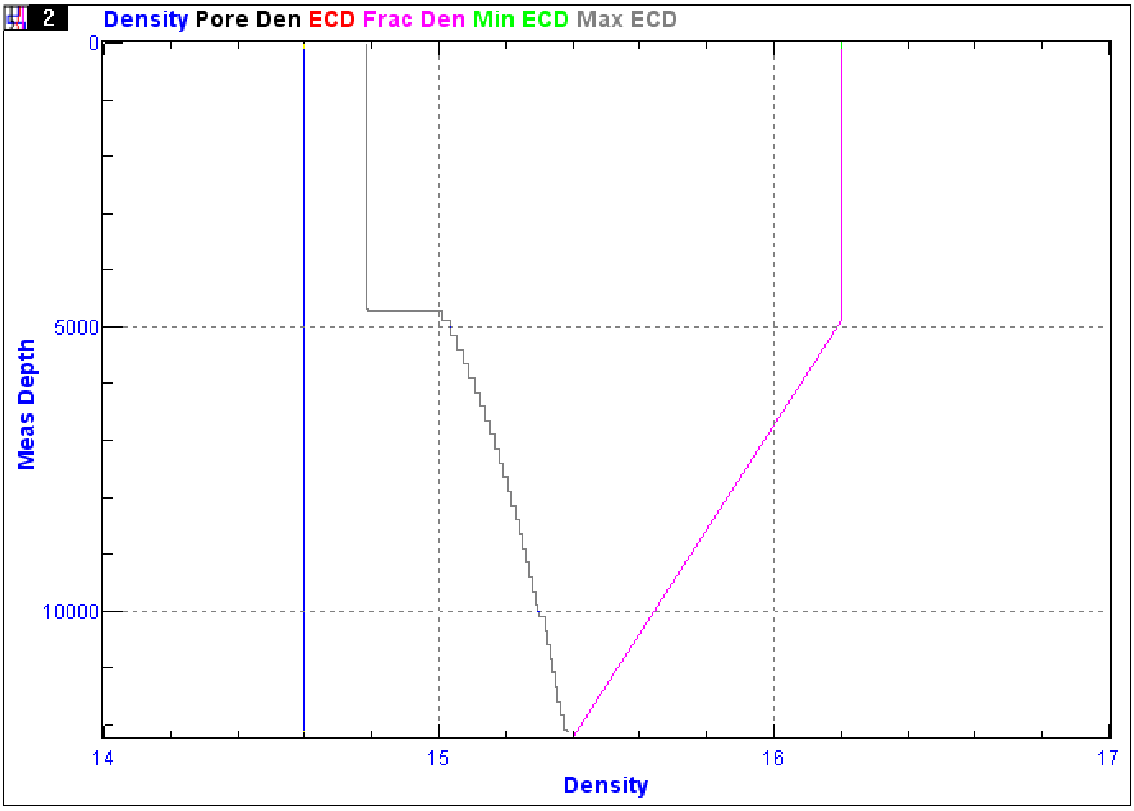


Figure D-0-36 ECD compared with the fracture gradient when circulating Versatec OBM at 6BPM with Baker ZX LH

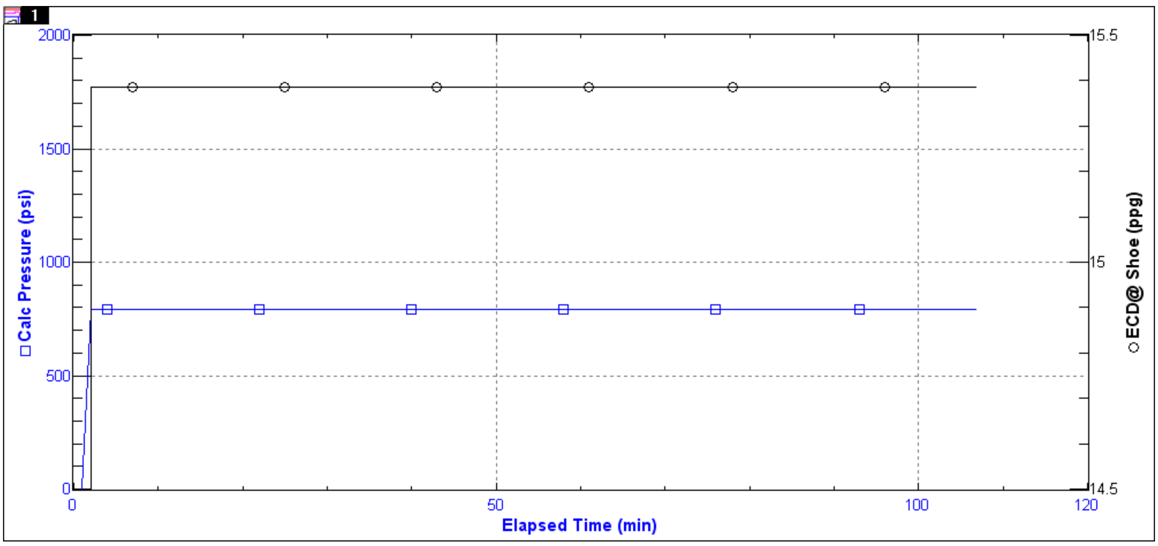


Figure D-0-37 Circulating pressure and ECD at shoe when circulating cement Versatec OBM at 6BPM with Baker ZX LH

Fluid Location

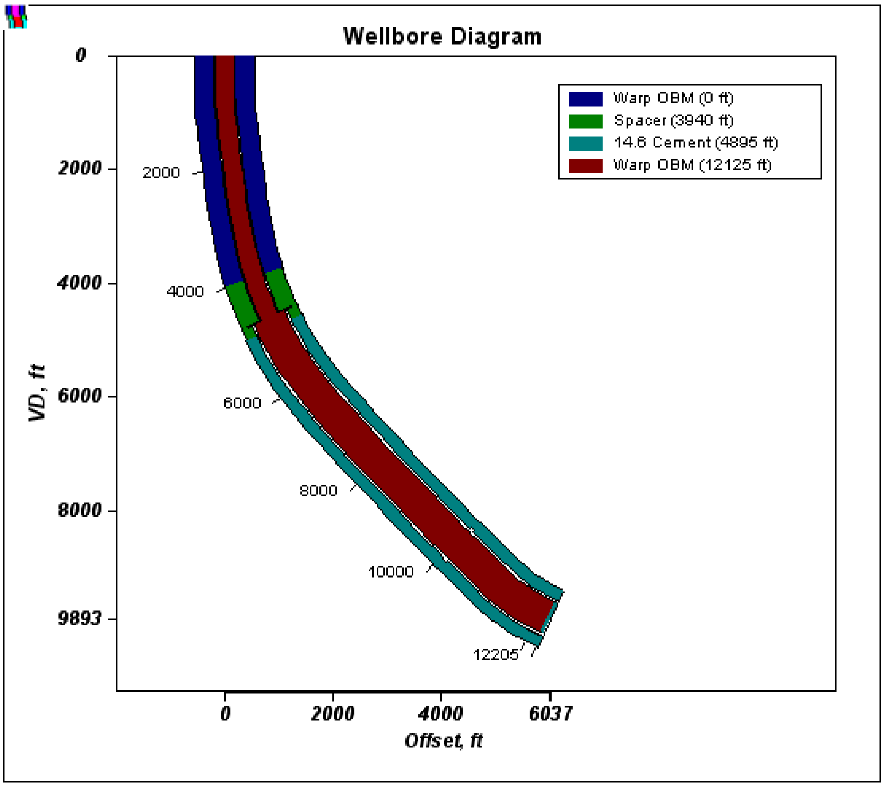


Figure D-0-38 Fluid location with Warp OBM circulated at 5BPM

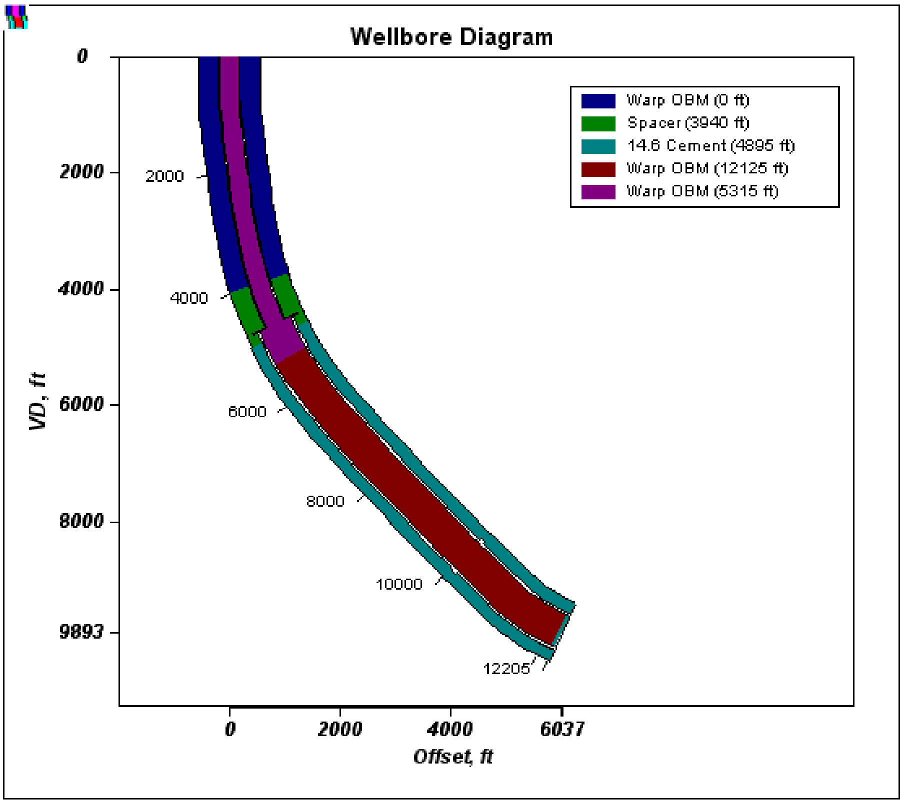


Figure D-0-39 Fluid location with Warp OBM circulated at 3BPM and 5BPM

CASE 17: 9 7/8-in liner set at 12205 ft MD (9893 ft TVD)

Cement , Spacer, Versaflex LH, and Warp OBM mixing/pumping at 5 BPM

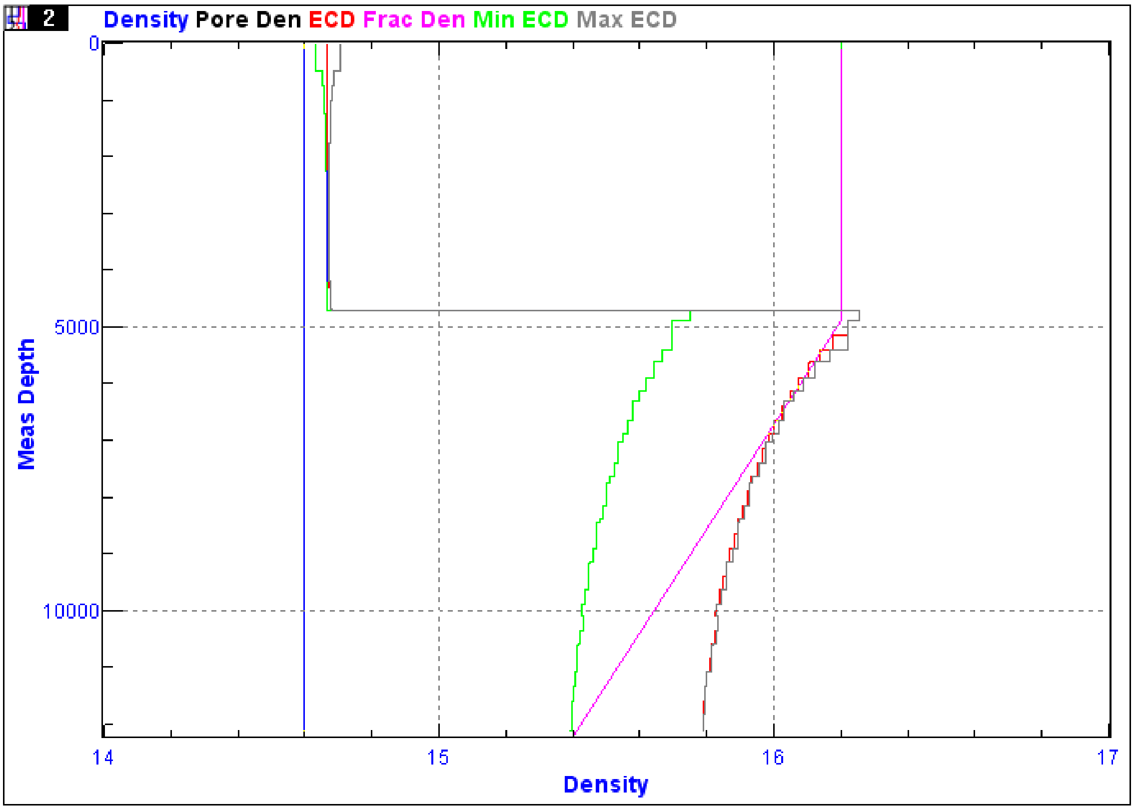


Figure D-0-40 ECD compared with the fracture gradient when circulating cement, spacer and Warp OBM at 5BPM with Versaflex LH

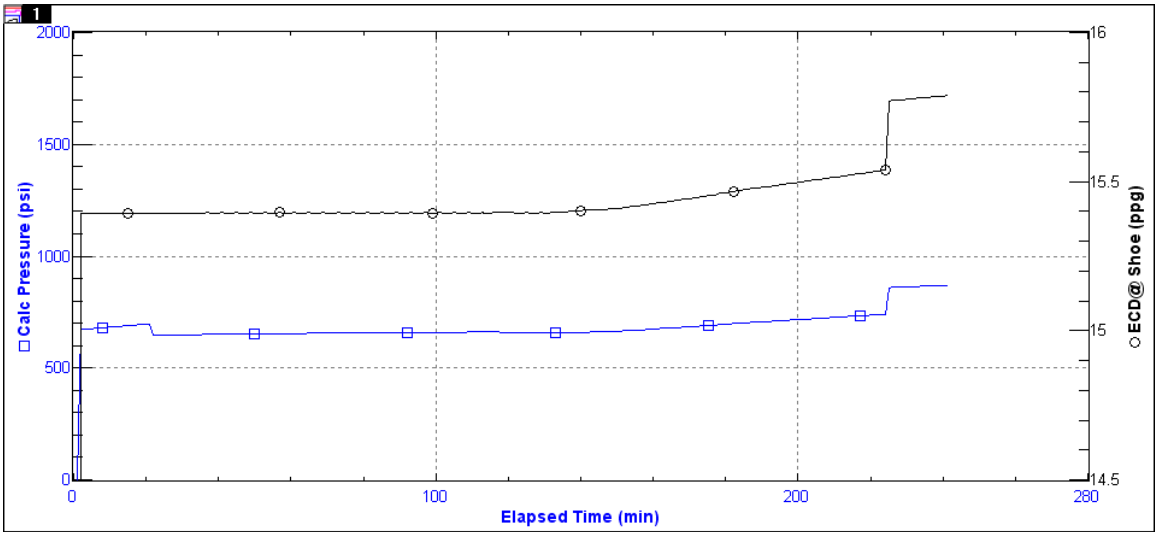


Figure D-0-41 Circulating pressure and ECD at shoe when circulating cement, spacer and Warp OBM at 5BPM with Versaflex LH

CASE 18: 9 7/8-in liner set at 12205 ft MD (9893 ft TVD)

Cement , Spacer, Versaflex LH, and Warp OBM mixing/pumping at 5 BPM x 3 BPM

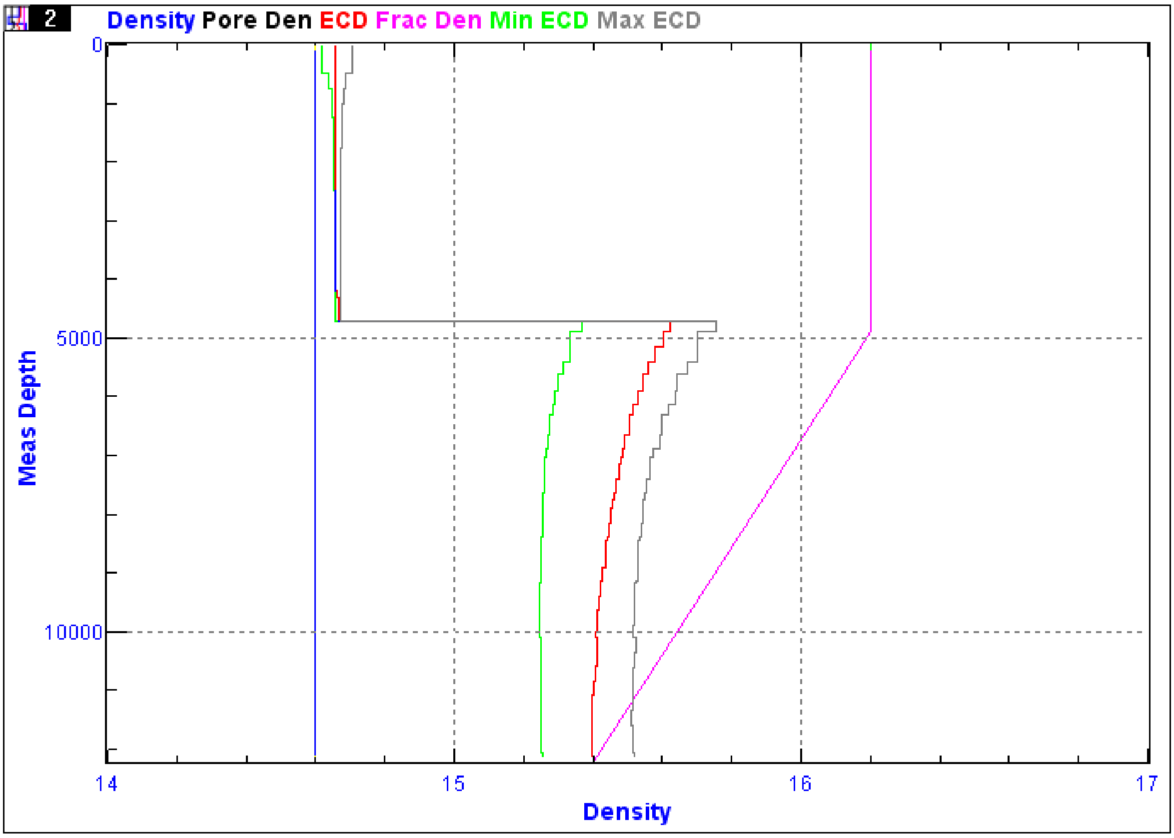


Figure D-0-42 ECD compared with the fracture gradient when circulating cement, spacer and Warp OBM at 5BPM x 3BPM with Versaflex LH

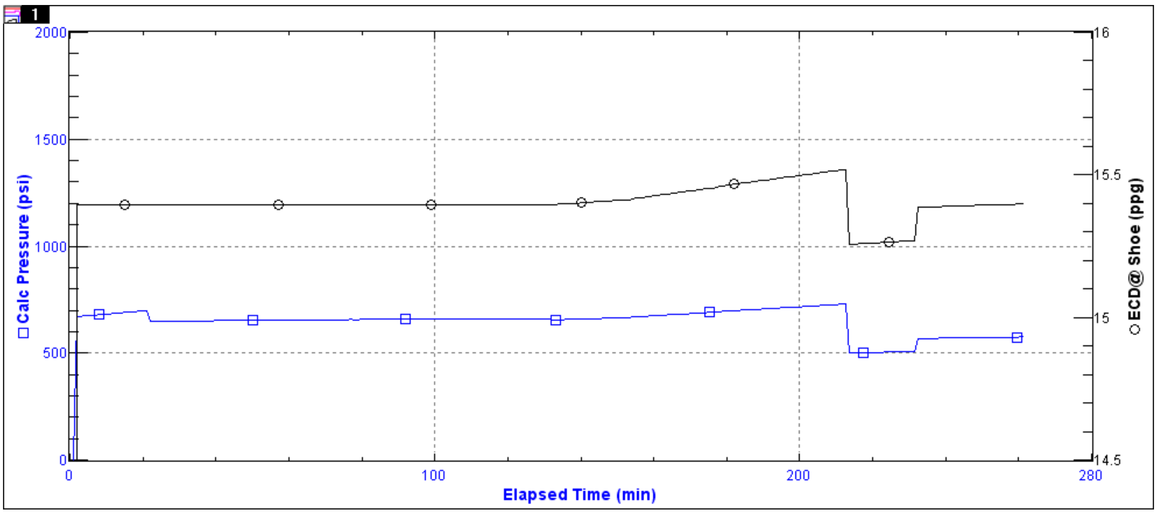


Figure D-0-43 Circulating pressure and ECD at shoe when circulating cement, spacer and Warp OBM at 5BPMx3BPM with Versaflex LH

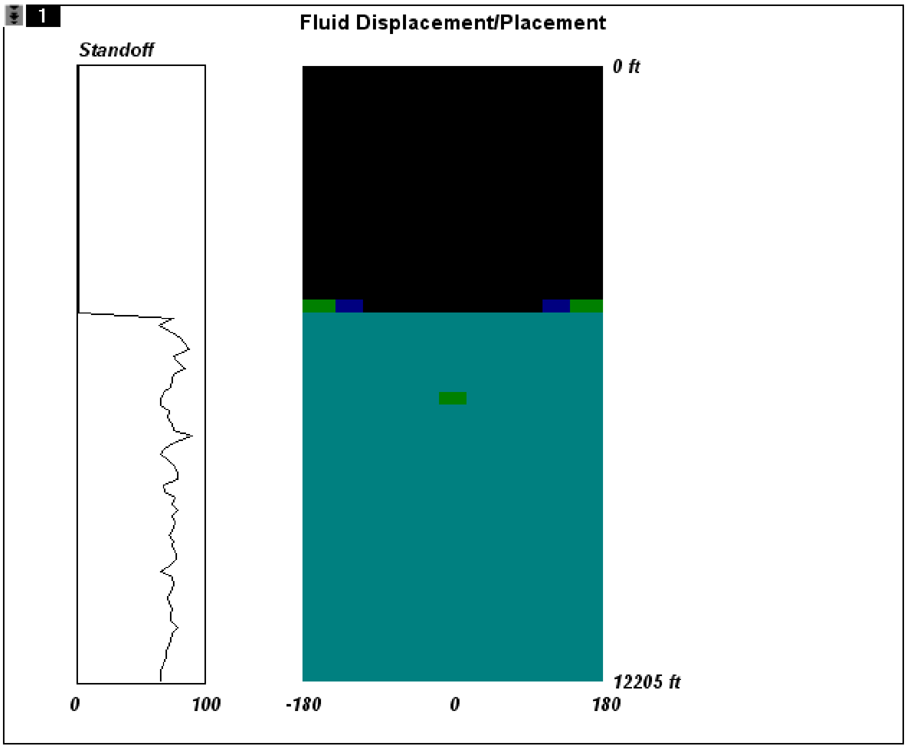


Figure D-0-44 Mud Displacement Effiency (60 % Liner Standoff)

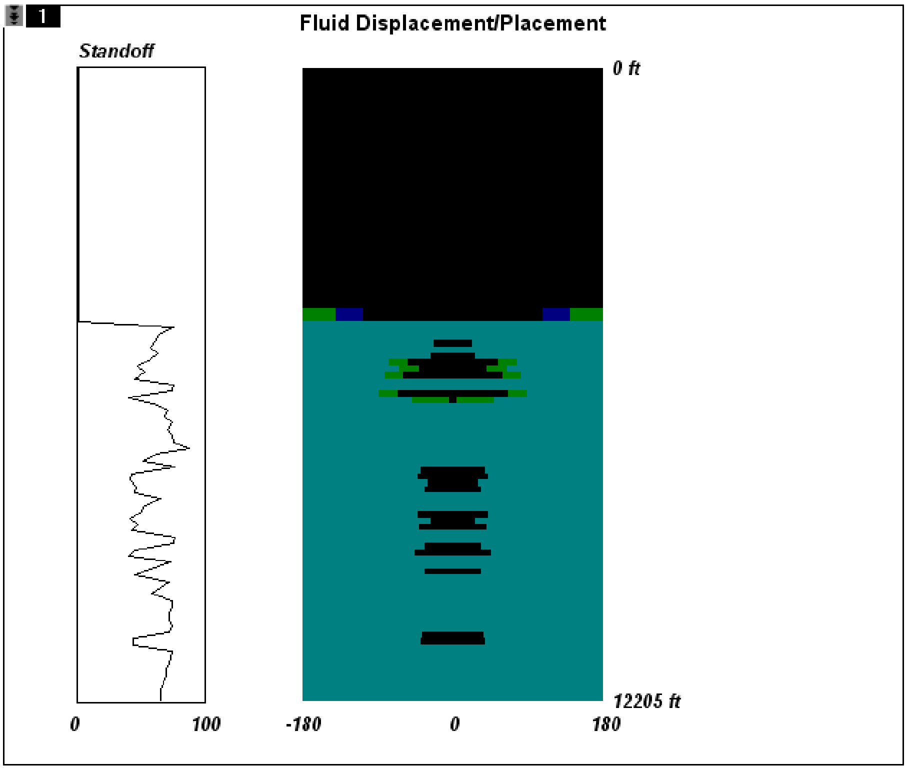


Figure D-0-45 Mud Displacement Effiency (40 % Liner Standoff)

9 7/8-in liner set at 12205 ft MD (9893 ft TVD)

CASE 19: Cement , Spacer, Baker ZX LH, and Warp OBM mixing/pumping at 5 BPM

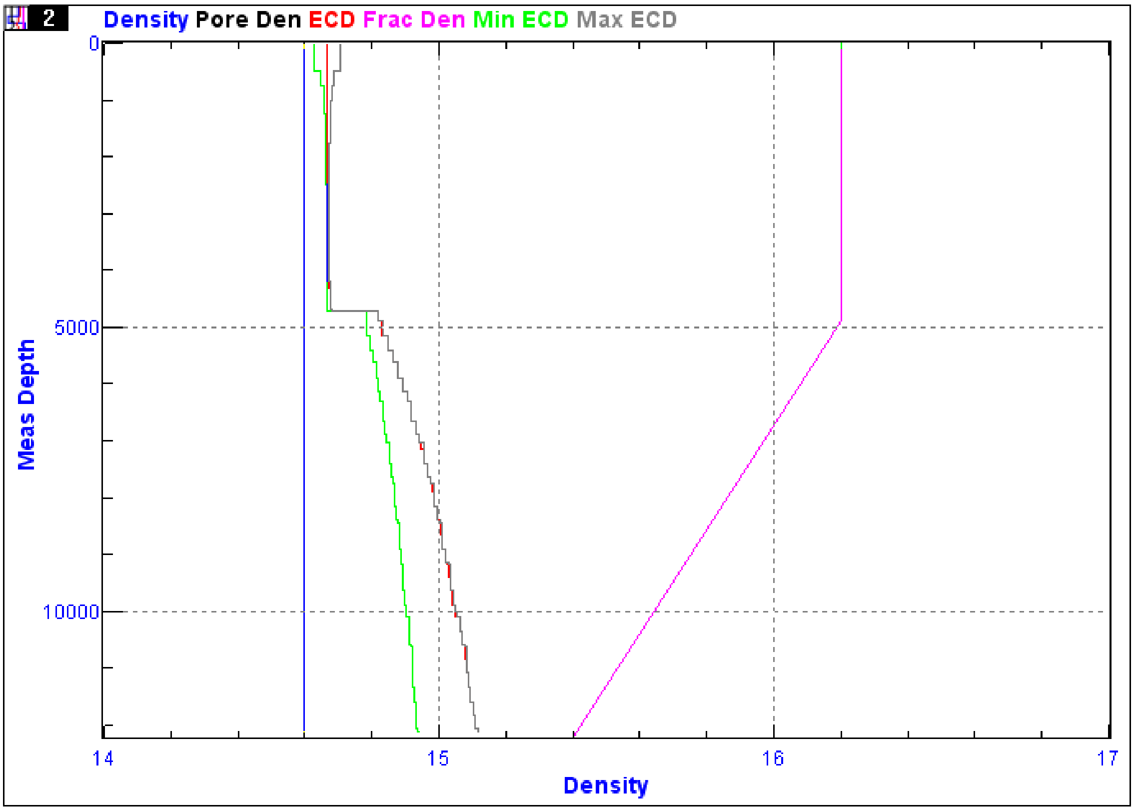


Figure D-0-46 ECD compared with the fracture gradient when circulating cement, spacer and Warp OBM at 5BPM with Baker ZX LH

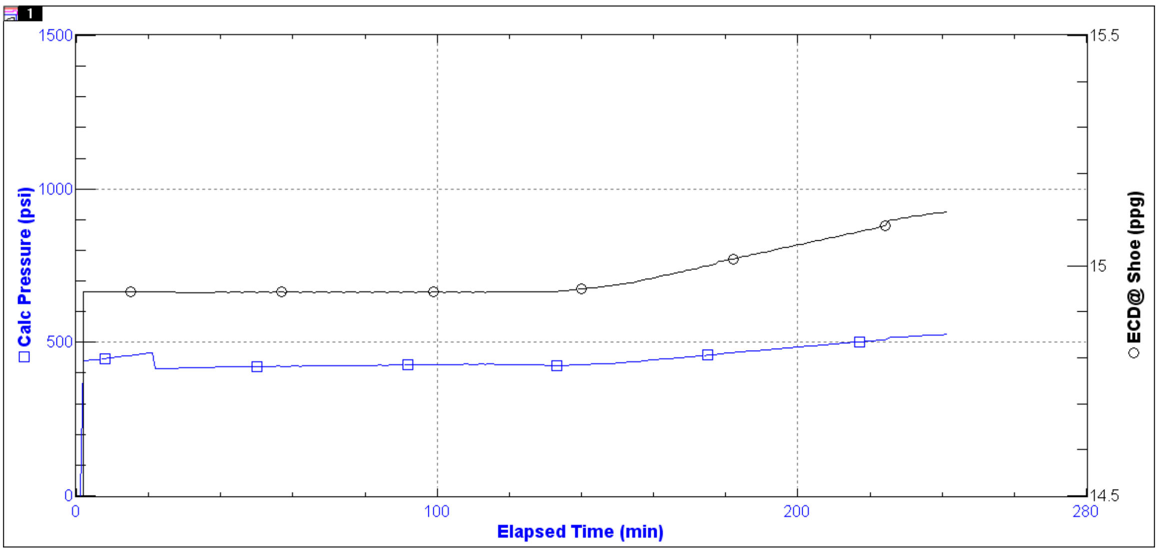


Figure D-0-47 Circulating pressure and ECD at shoe when circulating cement, spacer and Warp OBM at 5BPM with Baker ZX LH

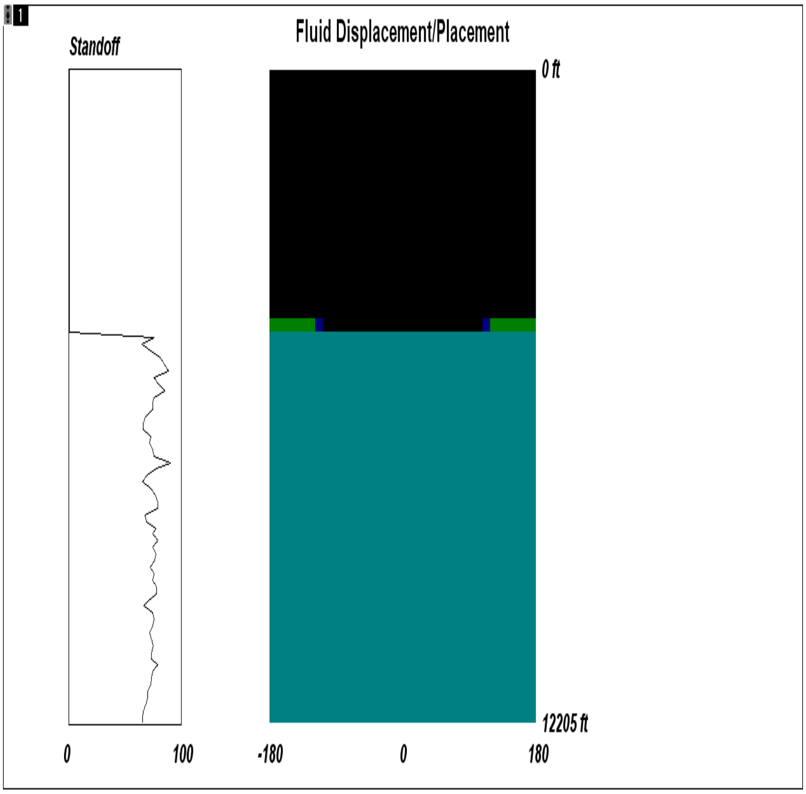


Figure D-0-48 Mud displacement effiency (60 % Liner Standoff)

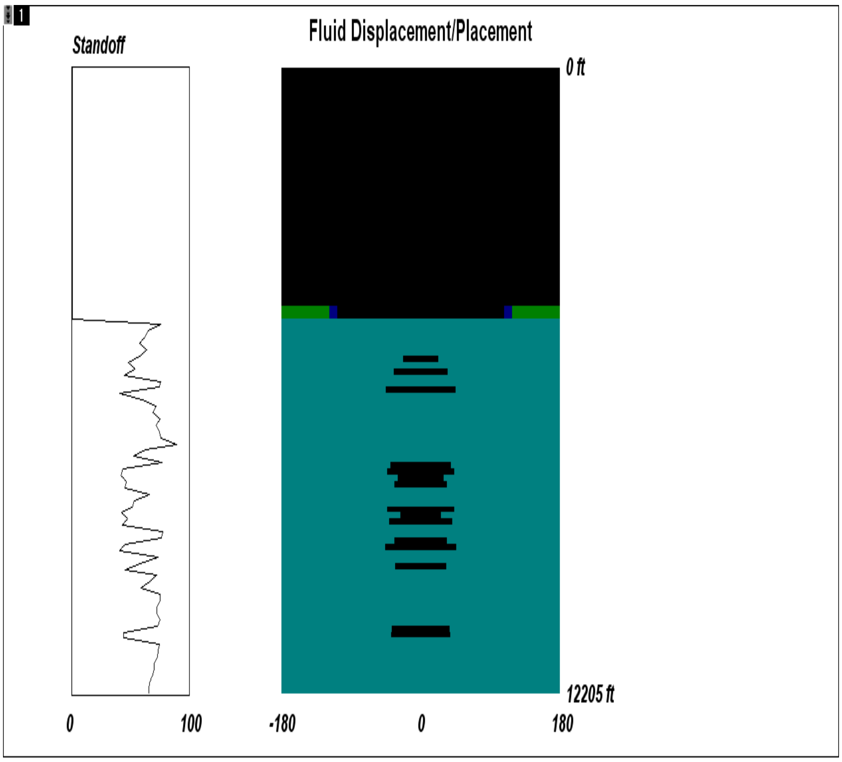


Figure D-0-49 Mud displacement effiency (40% Liner Effiency)

9 7/8-in liner set at 12205 ft MD (9893 ft TVD)

CASE 20: Cement , Spacer, Baker ZX LH, and Versatec OBM mixing/pumping at 5 BPM

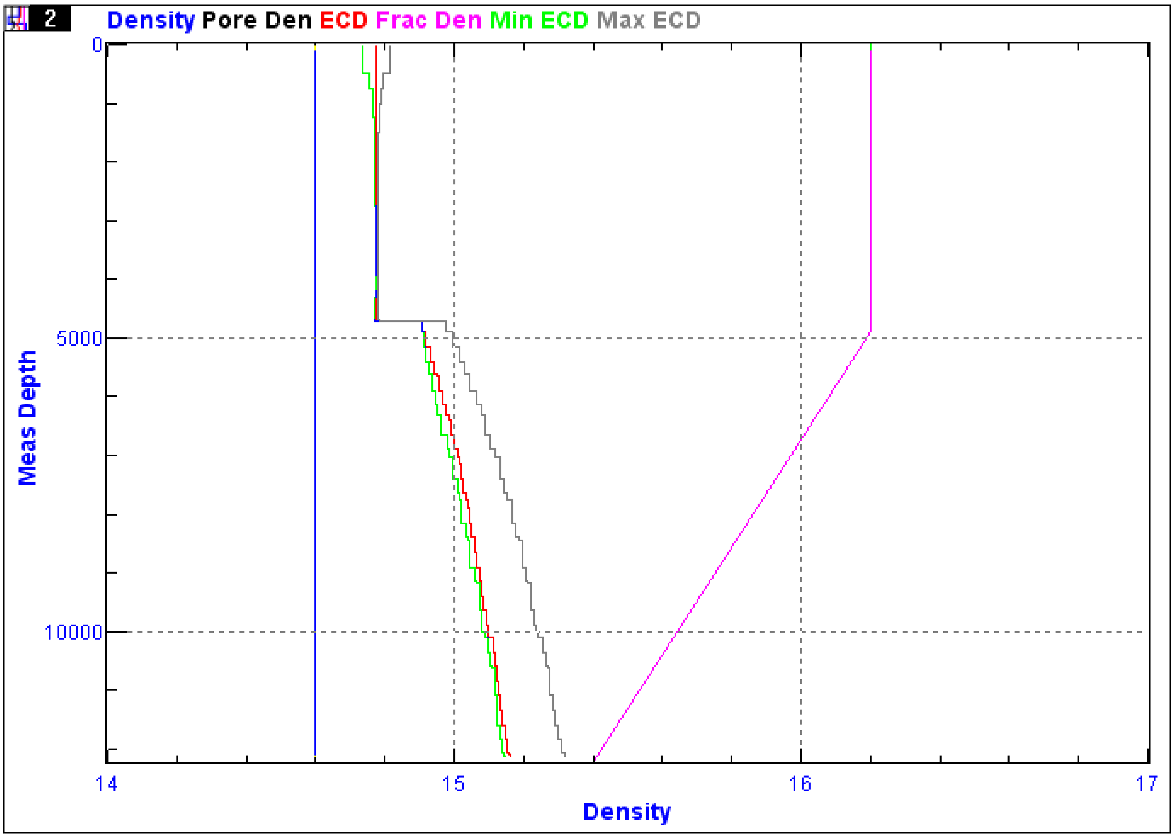


Figure D-0-50 ECD compared with the fracture gradient when circulating cement, spacer and Versatec OBM at 5BPM with Baker ZX LH

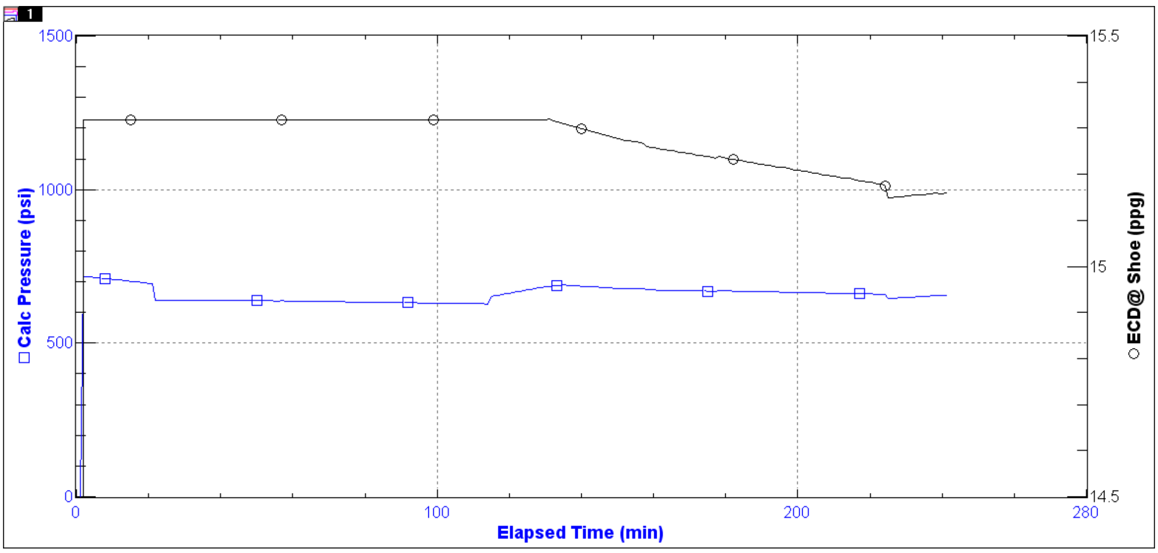


Figure D-0-51 Circulating pressure and ECD at shoe when circulating cement, spacer and Versatec OBM at 5BPM with Baker ZX LH

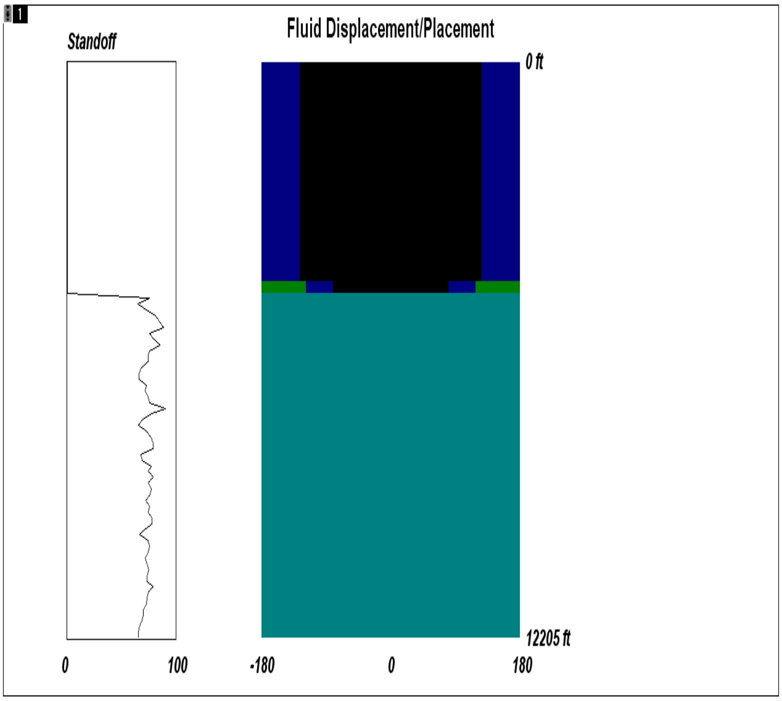


Figure D-0-52 Mud displacement effiency (60 % Liner Standoff)

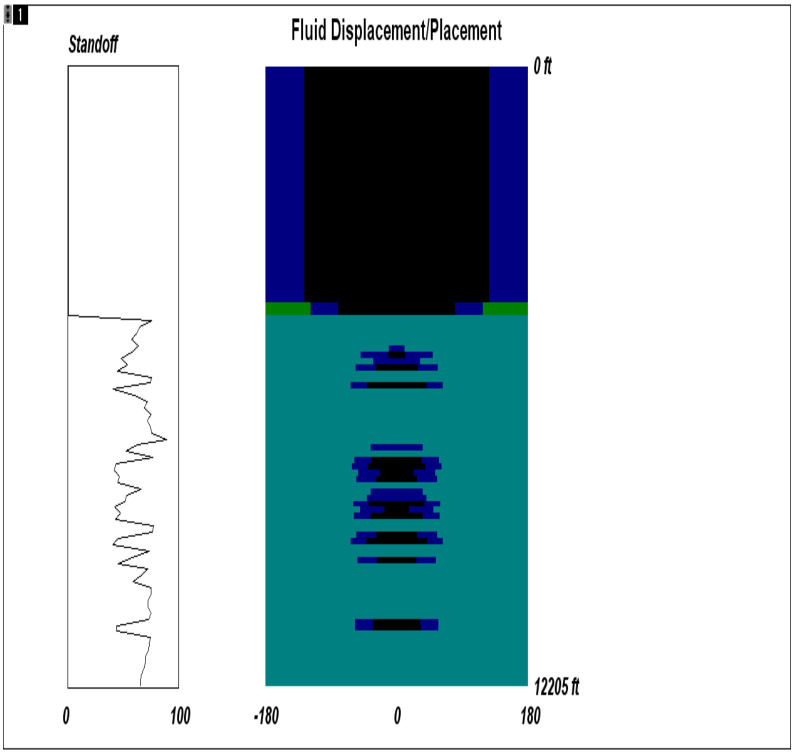


Figure D-0-53 Mud displacement effiency (40 % Liner Standoff)