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Author: Thomas Mæland	…………………………………………… (signature author)
Instructor: Erik Skaugen Supervisor(s): Dale Mathews	
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Abstract

Foam cementing the reservoir liner has proven to be a good solution for achieving zonal isolation due to its low permeability and high compressive strength. However, out of the 32 reservoir liners cemented on the Ekofisk M platform only 16 were defined as 100 % successful.

In this thesis foam cement and liner string components are introduced before evaluating the outcome of the different jobs. A success criterion for the outcome is established, incorporating liner centralization, zonal isolation and liner movement. The criterion regards the outcome a success if liner manipulation is maintained throughout the job and no remedial job is needed, a semi-success if manipulation is maintained for most of the job and no remedial job is needed, and a failure if none of the previously mentioned.

Data from all the reservoir liner cementing operations are gathered and the outcome of each is evaluated based on the above criterion. 16 of the liners were cemented successfully, 6 were semi-successfully, and the last 10 were failures. Failing to reestablish rotation after setting the liner hanger is the most common reason for failure, 7 out of 10 failures can be related to this.

Wellbore inclination and liner length are both parameters which seems to contribute to the outcome of foam cementing the reservoir liner. 13 of the 32 wells have an inclination above 80 º at the liner shoe. Out of these 13 wells only 4 are regarded as successful, the rest are either semi-successful, 4, or failures, 5. Even though failures are observed for all inclinations, this happens more frequently at higher inclination.

The success rate also seems to be influenced be the length of the liner. For shorter liners, i.e. with a length below 2000 ft, nearly 78 % of the cement jobs were successful, whereas the same percentage for liners with a length between 5000 ft and 6000 ft is 25 %. In fact, a near linear trend is observed for the success rate as the length increases.

Table of Content

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A special thanks to Dale Mathews for being my supervisor and including me in the M-team. I would also like to thank Bjarte Aarøy and Stian Brevik their help and guidance over the past months. I really appreciate the time and effort that all of you have spent on explaining and discussing all sorts of things with me, and for answering more than a few of my questions!

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Thomas Mæland
Stavanger, 12th of June 2009

Introduction

The Ekofisk Field was discovered in 1969. Since then, hundreds of wells (including sidetracks) have been drilled and completed. In the last 10 years, using a reservoir liner instead of a casing has become more accepted, due to the lower amount of steel used, and the ability to sidetrack. When cementing this liner, zonal isolation is of the outmost interest to achieve a good producer. This is due to the big pressure differences between different zones in the reservoir caused by production and injection over time.

The Ekofisk Field is located in the southern section of the Norwegian North Sea in Block 2/4. The reservoir is an elongated anticline with the major axis running North-South, covering approximately 12 000 acres. The producing horizons of the Ekofisk Field are the Ekofisk and Tor formations. Both formations are mainly built up of fine-grained limestones, or chalks, that are separated by a tight zone. The Ekofisk formation varies from 350 to 550 feet in thickness, with porosities from 25 to 48 percent. The Tor formation has a thickness in the range of 250 to 500 feet, and its porosity is between 30 and 40 percent (Takla and Sulak 1989; Johnson et al. 1989; Sulak 1990; Hermansen et al. 1999).

Since the field came on production in 1971, over 3500 millions BOE have been produced (NPD 2009). The initial reservoir pressure of some 7000 psi has decreased due to depletion caused by production, reducing the average reservoir pressure to about 5000 psi in the Ekofisk formation and 4000 – 6000 psi in the Tor formation (ConocoPhillips 2008).

The main purpose of cementing a reservoir liner (or casing) is to achieve zonal isolation. Getting the cement sheath to cover the entire annulus between the liner and formation is a key element in providing isolation, thus rotating the liner during the pumping and displacement of the cement slurry is important factor.

This thesis will focus on foam cementing reservoir liners and cementing the liners in wells drilled from the M wellhead platform in the Ekofisk field is evaluated. Based on case studies and well statistics some trends and conclusions are observed.

1 Statement of Theory and Definitions

In 1903, Perkins Oil Well Cementing Co. performed the first reported cement job in an oil well in California (Piot, 2009). Since then cementing has developed to become a discipline of its own within the oil industry. Cementing in the oil industry is the process of pumping a cement slurry through a casing (or liner) and back up the annulus between the casing (or liner) and the formation where the slurry is given time to cure and develop its compressive strength. The main objective of filling the annulus with cement is to prevent annular migration of fluids by using the cement to provide zonal isolation. Other reasons for cementing are axial support of the casing (or liner), protection against erosion and corrosion, and support of the borehole wall.

1.1 Cement and Slurry Design

The base slurry for cementing a casing or liner in the oil industry normally consists of cement, water and some additives to adjust the properties of the slurry. It is common knowledge that cement is made of pulverized clinker produced by using a rotary kiln. The major clinker components are calcium silicates, calcium aluminates, and calcium aluminoferrites. Normally some form of calcium sulfate, usually gypsum, is added to the mixture to form the final product. The amount of each clinker component affects the properties of the cement (Nelson and Guillot 2006).

1.1.1 Conventional Cement

Conventional cement slurry for the reservoir is normally in the region of 14 – 16 ppg. If the slurry density is reduced to 11 – 12 ppg, by adding water or cement additives, the cement might not be able to provide adequate zonal isolation as the compressive strength and permeability properties of the slurry is out of specification (Nelson 1990). Other drawbacks of conventional cement are:

- shrinkage of cement as it sets,
- fracturing the reservoir due to high density, and
- cracks developed as a result of the forces involved during start-up and shut-down of the well and thermal and mechanical loading, i.e. conventional cement is fairly brittle.

In total this has paved the way for foam cementing the reservoir liner (or casing). However, different classes, additives, and strength development of conventional cement will be introduced in the next sections since these are also applies for foam cement.

1.1.1.1 API Cement Classes

Cement is divided in eight classes by the American Petroleum Institute, API. Table 1 shows the classes and a short description of the different grades.

Class	Description of grades
A	Intended for use when special properties are not required.
B	Intended for use when conditions require moderate or high sulfate resistance.
C	Intended for use when conditions require high early strength.
D – F	Also known as “retarded cements” intended for use in deeper wells with different requirements to temperature and pressure. Not commonly used today.
G – H	Intended for use as basic well cement, and are by far the most commonly used cements today.

Table 1: API Classification of Cements

Today, the classes G and H are normally used and cement additives are introduced to the mixture to alter the properties of the cement slurry.

1.1.1.2 Cement additives

Over the years numerous additives have been developed to modify cement properties to a given situation. These additives are grouped in different categories where accelerators, retarders, extenders, weighting agents, dispersants, fluid-loss control agents, and lost-circulation preventing agents are the most common (Nelson and Guillot 2006).

Accelerator is a term given to additives which reduces the setting time, accelerate the hardening process, or both. The most frequently used accelerator is chloride salts, but also other inorganic salts like carbonates, silicates, and aluminates are used.

If the objective is to increase the setting time, a retarder is added to the slurry. A retarder increases the pumping time of the cement slurry which is necessary for deeper wells where it takes longer to place the cement in the annulus and the temperature can be higher. Lignosulfonate is the best example of a good retarder.

To reduce slurry density and/or increase the slurry yield extenders are added to the cement mixture. Clay minerals like bentonite or sodium silicates, and pozzolans like fly ash, all behave as extenders when part of a cement slurry.

Weighting agents are used if heavy weight, i.e. more than normal density, is needed to control the pressure. Ilmenite, hematite, barite, and manganese tetraoxide are all common weighting agents. Denser cement can also be achieved simply by reducing the amount of water in the slurry, but the downside of such an approach makes it applicable only for smaller increases in weight.

A dispersant lowers the slurry viscosity, and makes the slurry more pumpable. Polynapthalene sulfonate, PNS, polymelamine sulfonate, PMS, and lignosulfonate are among the additives with this attribute.

Fluid-loss control agents help reduce the slurry dehydration either by increasing the aqueous phase viscosity with cellulosic polymers, by reducing the permeability of cement filter cake, or by introducing particles that will bridge across the pore openings.

To prevent losses to the formation lost-circulation prevention agents like gilsonite, nut shells, gypsum, and bentonite are introduced to the slurry.

1.1.1.3 Hydration of conventional cement

Oilfield cement consists of a variety of different components, each with its own set of chemical reactions, often interfering with other reactions in the mixture. The result is a complex process, in fact the hydration mechanism of cement is modeled using the hydration of the largest component in cement, which is C_3S or alite. In brief hydration is the process where cement develops its strength as a result of reactions between water and compounds present in the cement. In more detail, hydration of C_3S involves five stages or periods (Nelson and Guillot 2006).

The first stage is called the preinduction period which begins during mixing of cement and water. This phase last only for a few minutes, and is followed by the induction period. Most of the hydration happens in the acceleration and deceleration periods, also referred to as the setting period. At the acceleration stage the cement begins to develop strength, which is continued at a slower rate in the deceleration period. At this time the porosity will start to decrease as a result of hydrate deposition. Total hydration is never attained as it continues at a slow pace in the diffusion period. However, the set cement reaches a point where no evident changes can be seen.

1.1.2 Foam Cement

Foam cement, as defined by Nelson and Guillot (2006), contains coarse dispersions of base cement slurry, nitrogen (usually), a foaming surfactant, and other materials to provide foam stability. Usually, nitrogen is added to conventional 15 – 16 ppg base cement slurry to form foam. The density of nitrogen is small compared to the density of the base slurry, and can therefore be neglected. By varying the amount of nitrogen added to the mixture, the foam density can then be altered.

The volume of gas introduced to the slurry will also determine the foam quality. The quality of foam is defined as the ratio of the volume occupied by gas to the total volume of foam,

$$Q_{foam} = \frac{V_{gas}}{V_{foam}} \times 100 \qquad \textbf{(1-1)}$$

where
Q_{foam} is the foam quality in percent,
V_{gas} is the volume occupied by gas in barrels, and
V_{foam} is the total volume of the foamed mixture in barrels.

From equation (1-1) it is obvious that if the volume of gas added to the mixture is increased while the cement slurry volume is kept constant, there will be less fluid available to form a liquid film on the gas bubbles. Opposite, if the volume of gas is kept constant and the cement slurry volume is increased, the foam will consist of smaller gas bubbles covered by thicker liquid films. For foamed cement, the quality percentage does not exceed 80% and is usually less than 50%.

The volume occupied by nitrogen in the foam mixture will vary with pressure and temperature, which means that equation (1-1) will give a lower foam quality with increasing true vertical depth, TVD. This follows from the fact that nitrogen will be compressed as a function of depth.

A foam cement job can be performed either as a constant density job or with a constant nitrogen rate (McElfresh and Boncan 1982). In a constant density approach, the density is kept constant by increasing the injection rate of nitrogen as the pumping proceeds. Alternatively, the nitrogen rate is constant resulting in a job with increasing density from top cement to shoe, see Figure 1 for both scenarios.

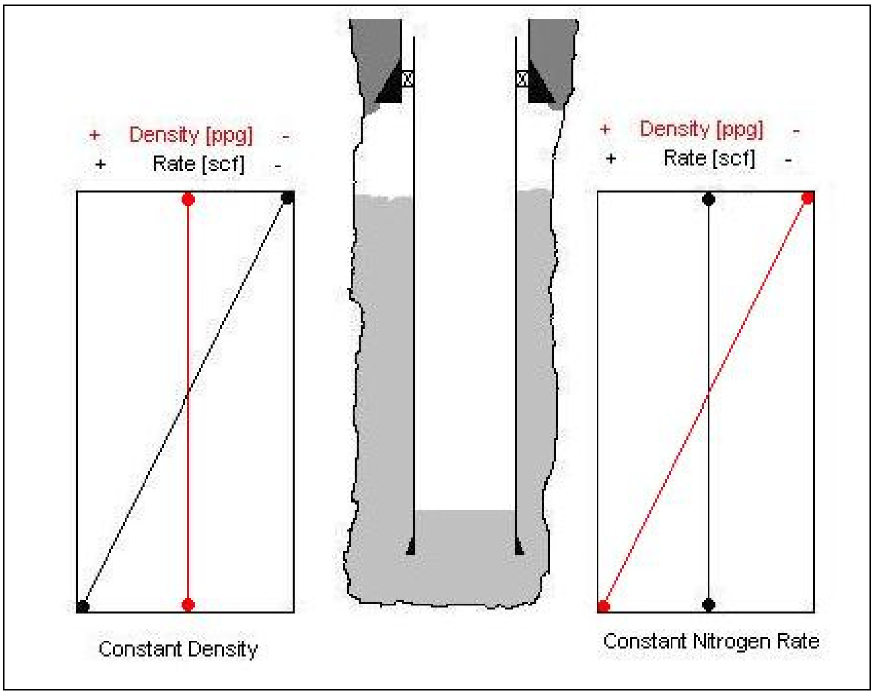

Figure 1: Rate and density for vertical foam cement job

For a horizontal wellbore, it is practical to split the well into one vertical and one horizontal section, Figure 2. The vertical section will behave as described for vertical wells, Figure 1. In the horizontal section TVD is constant, and hence no changes in hydrostatic pressure. In short, this implies that both the density and nitrogen rate will be constant in this section.

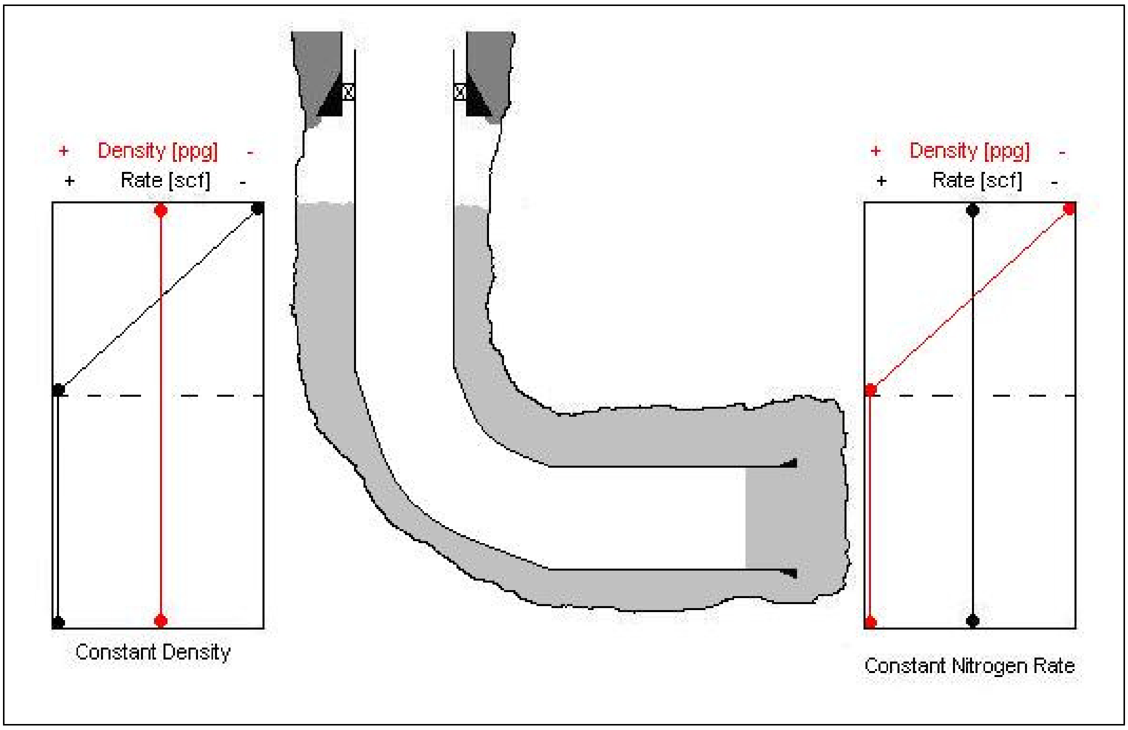

Figure 2: Rate and density for horizontal foam job

Several papers have been written on foamed cement and its properties. Degni et al. (2001) reported of benefits like superior mud displacement, high strength, low adjustable density, ductility, and capability to prevent gas migration when using foamed cement for liner applications. Further, Kopp et al. (2000) investigated how foamed and conventional cements behave when it comes to zonal isolation. Field experience indicates that foamed cement gives better isolation than conventional cement. More recently, Green et al. (2003) presented a paper that indicates that foamed cement outperforms conventional cement for zonal isolation and dynamic curing of losses in chalk formations on the Eldfisk Field in the southern North Sea. In addition, Harlan et al. (2001) reports of a 25 % reduction in total well costs and a 75 % reduction in total fluid losses when using foam cement for horizontal liners.

1.1.2.1 Topside Requirements for foam cementing

In addition to the equipment and personnel needed for a conventional cement job, a foam cement job also require a:

- foam manifold,
- de-foam manifold if cement returns to surface, e.g. reverse circulate out excess cement ,
- nitrogen tank,
- nitrogen unit,
- black eagle hoses which are capable of pumping fluids containing gas under high pressures,
- zoneseal skid that add soap and stabilizer to the slurry,

- foam basket with tools and spare parts,
- foam engineer,
- foam supervisor,
- nitrogen operator, and
- instrument technician.

The result of all the extra requirements is higher costs on logistics, operation, and accommodation. However, papers by Harlan et al. (2001), Degni et al. (2001), and Kopp et al. (2000) all indicate that foam cement is cost-effective despite higher initial costs than conventional cement. This is because foam cement in general improves the zonal isolation, and hence, provides considerable cost savings over the life of the well.

1.1.3 Conventional versus Foam Cement

In the chapters regarding conventional and foam cement many advantages and disadvantages with the different approaches are mentioned. These and others are summarized in this section (Nelson 1990; Kopp et al. 2000; Degni et al. 2001; Harlan et al. 2001; Green et al. 2003; Griffith et al. 2004; ConocoPhillips 2004; Nelson and Guillot 2006).

Advantages by using conventional cement are:
- lower cost, and
- lower amount of equipment and personnel involved.

Disadvantages by using conventional cement are:
- low compressive strength,
- high permeability,
- relatively high density, and
- brittle.

Advantages by using foam cement are:
- good compressive strength,
- low permeability,
- slurry density can vary from 0 – 15 ppg (theoretically),
- high mud displacement efficiency
- lower torque required to rotate liner, and
- ductile, i.e. foam cement are more flexible than conventional cement.

Disadvantages by using foam cement are:
- involves more equipment and personnel to perform the cementing, and
- higher initial cost.

1.1.4 Cement Calculations

When planning a foam cement job, several calculations have to be performed. In practice all of them are solved with highly sophisticated software, but these simulation tools will not be discussed in this thesis. The basic equations, however, will be presented in this chapter.

1.1.4.1 Down hole Volume Calculations

When calculating the volume, there are in general three different volumes that come into play. First, the volume between the casings (or casing and liner or liners) has to be calculated. Next, the volume between the casing, or liner, and the open hole is decided, and finally the volume of the shoe track is determined. The equations needed for performing the volume calculations for cementing a reservoir liner in a previous set liner is introduced below.

Reservoir liner inside previous liner:

$$V_1 = \frac{\pi}{4}\left(ID_{prev}^2 - OD_{RL}^2\right)\cdot L_1 \cdot 0{,}178108 \qquad \textbf{(1-2)}$$

where
V_1 is the volume in barrels,
ID_{prev} is the inner diameter of the previous set liner or casing in feet,
OD_{RL} is the outer diameter of the reservoir liner in feet,
L_1 is the length with overlapping liners in feet, and
0,178108 is the conversion factor from cubic feet to barrels.

For a liner set through hydrocarbon bearing formations, top of cement, TOC, have to be in compliance with NORSOK D-010 (2004). The acceptance criteria as per D-010 is that the cement shall either be 656 feet (i.e. 200 m) above permeable formation with hydrocarbons or to the previous casing or liner shoe, whichever is less.

A company procedure in ConocoPhillips Norway is to have the top of liner, TOL, approximately 150' TVD above the Balder formation. Balder are generally some 400 – 500' TVD above the Ekofisk formation, i.e. the company procedure is in compliancy with NORSOK requirements.

Reservoir liner in open hole:

$$V_2 = \frac{\pi}{4}\left(D_{OH}^2 - OD_{RL}^2\right)\cdot L_2 \cdot 0{,}178108 \cdot CF \qquad \textbf{(1-3)}$$

where
V_2 is the volume in barrels,
D_{OH} is the diameter of the hole in feet,
OD_{RL} is the outer diameter of the reservoir liner in feet,
L_2 is the length of liner in open hole in feet,
0,178108 is the conversion factor from cubic feet to barrels, and

CF is a hole diameter correction factor.

Shoe track in reservoir liner:

$$V_3 = \frac{\pi}{4} \cdot ID_{RL}^2 \cdot L_3 \cdot 0{,}178108 \qquad \textbf{(1-4)}$$

where
V_3 is the volume in barrels,
ID_{RL} is the inner diameter of the reservoir liner in feet,
L_3 is the shoe track length in feet, and
0,178108 is the conversion factor from cubic feet to barrels.

Total volume:

$$V_{TOT} = \sum_{i=1}^{3} V_i \qquad \textbf{(1-5)}$$

1.1.4.2 From surface to down hole volume

Independent of how the nitrogen is added to the slurry, either at constant rate, constant density, or a combination, the surface volumes has to be calculated. This can be done by converting the down hole volume from equation (1-5) using an advanced cementing software. The software is taking the temperature profile, pressure variations, and other aspects into account when calculating the surface volume of cement and the volume of nitrogen that will be injected.

1.2 Liner

There exist different types of liners. These are often divided into four broad categories (Nelson and Guillot 2006):

- drilling or intermediate liner,
- production and reservoir liners,
- scab liner, and
- scab tieback liner.

This thesis, however, will be focusing on reservoir liners, and cementing these liners using foam cement.

Since the length of the liner is less than the present well depth, the top of the liner is usually connected to a drill pipe in order to be lowered down to its intended position. This connection to a drill string makes it possible to rotate the liner from the drill floor (or topdrive). It is also possible to pump up the pressure inside the liner from the top, which is required if hydraulically activated equipment is used.

1.2.1 Reservoir Liner

The well design for the Ekofisk M field wells is to use a 6-5/8'' reservoir liner. This liner is hung off in the previous liner (or casing), i.e. it does not go all the way up to the surface (ConocoPhillips 2004).

Therefore, liners are generally much shorter than a conventional casing string, and they will normally be easier to move or manipulate during a cement job. This can be achieved either by rotation, reciprocation, or by a combination of both. This movement will be beneficial for both mud removal and displacement of cement. Rotation is preferred over reciprocation, and positive rotating centralizers with angled blades are used to reduce the torque.

Other benefits from setting a liner rather than a conventional casing string includes logistics, rig-handling capabilities, wellhead design, drilling cost reduction, and contingency plans when drilling through unknown formations or encountering unexpected difficulties (Nelson and Guillot 2006).

The main objectives of setting and cementing a production liner are to:

1. install a well cemented liner over the entire reservoir interval to provide effective zonal isolation,
2. install a reservoir compaction strain tolerant completion that provides wellbore access throughout the well life, and
3. provide a monobore completion to facilitate future through-tubing operations.

1.2.2 Liner Hanger

A liner string is set using a liner hanger to hang off the string in the previous casing or liner. For a conventional hanger a cone in the liner hanger body moves a row of slips into the casing or liner wall preventing the liner from sliding down hole, see Figure 3 (Nelson and Guillot 2006). The number of rows of slips and cones can be increased if extra carrying capability is needed or wanted.

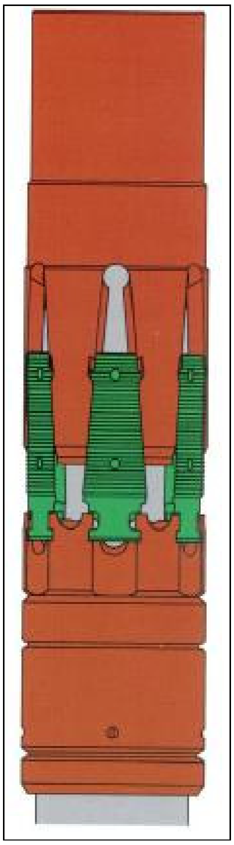

Figure 3: Liner hanger body with cone and slip (courtesy of Baker Hughes)

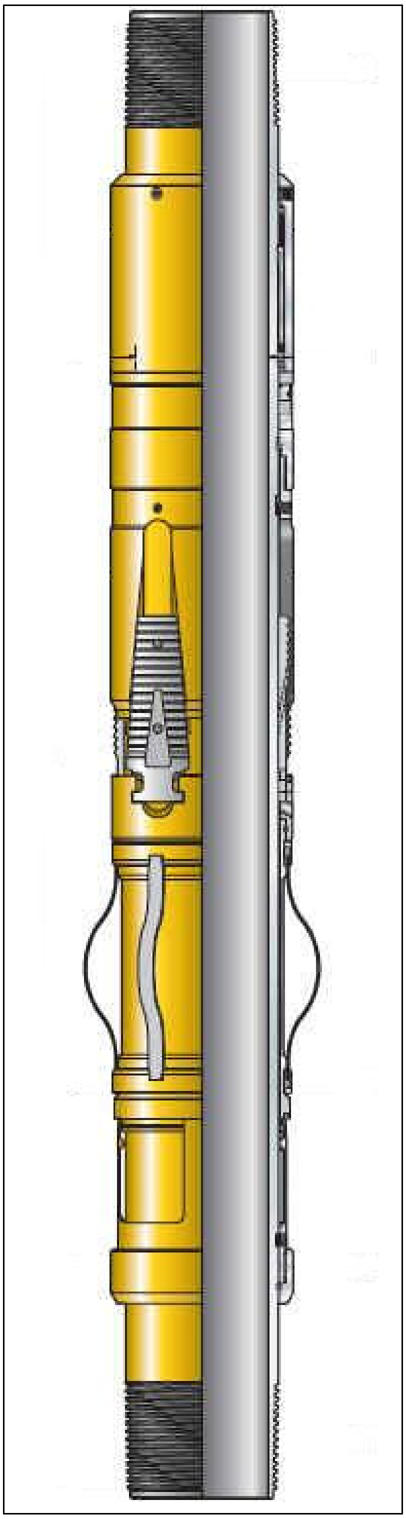

Figure 4: Mechanically set liner hanger (courtesy of Baker Hughes)

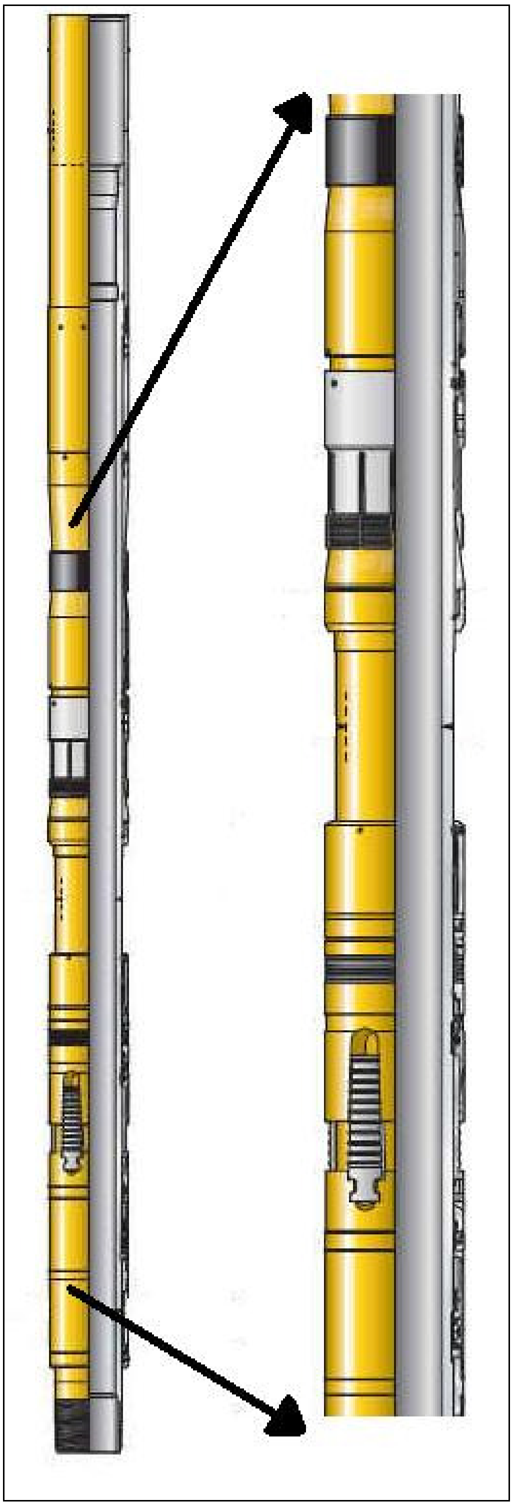

Figure 5: Hydraulic set liner hanger (courtesy of Baker Hughes)

In the marked today it exist three different types of liner hangers:

- mechanically set liner hangers,
- hydraulic set liner hangers, and
- expandable liner hangers.

Mechanically and hydraulic set hangers are often referred to as conventional hangers. The mechanically set hanger, Figure 4, is set by rotation and/or pipe manipulation, whereas the hydraulic set hanger, Figure 5, is set by dropping a ball and applying a predetermined differential pressure at the liner hanger. With mud both inside and outside the liner when setting the hanger, the pressure differential is a result of pressuring up the inside of the liner. Conventional hangers are set prior to pumping and displacing the cement. If an expandable hanger is used, the hanger is set after the displacement of cement is finished. The hanger is set by applying pressure, either against the upper valve in the shoe track or by dropping a ball which lands in a ball seat. Dropping a ball is only required if the valve can not take the pressure needed to set the hanger. An expansion cone will start to shift downwards while expanding the hanger making a metal-to-metal seal. All types of hangers have their advantages and disadvantages (Nelson and Guillot 2006; Halliburton 2007; Halliburton 2008).

Advantages by using a mechanically set hanger:

- They have good fluid bypass area for pumping,
- Can save rig time as there is no need for pressuring up,
- Can be set and unset multiple times on a single trip, and
- They are not sensitive to temperatures and/or erratic circulation pressure.

Disadvantages by using a mechanically set hanger:

- Can not be used in highly deviated and horizontal wellbores, and
- They rely on friction between the bow springs and the casing/liner.

Advantages by using a hydraulic set hanger:

- Can be used in highly deviated holes,
- They have a smooth outside profile,
- They do not require pipe manipulation,
- The liner string can be rotated before setting, and
- They have a preset and pretested shear mechanism.

Disadvantages by using a hydraulic set hanger:

- It takes time to pressure up and set the hanger, and
- Can risk overpressuring the formation.

Advantages by using an expandable liner hanger:

- They reduce the equivalent circulating density, ECD, which is the effective density of circulating a fluid against the formation i.e. an excellent bypass area provides smoother flow path past the hanger,

- The hanger is set after the cement job is finished, i.e. the liner can also be reciprocated, in addition to rotated, during displacement, and
- They have no moving parts
- They eliminates pre-set risk,
- They reduces the number of potential leak paths, and
- They provide superior annular seal.

Disadvantages by using an expandable liner hanger:
- if they are reciprocated during displacement the liner can get stuck in position off the wanted setting depth, and
- hard to perform remedial cement job.

1.2.3 Shoe Track Assembly

The shoe track assembly is located in the lower part of the liner string, and is in general made up of a float or reamer shoe, a float collar, a landing collar, and some pup joints, see Figure 11.

The float shoe, as shown in Figure 6 is located at the very bottom of the liner, and its main task is to guide the liner down through the open hole and to the desired setting depth. Several ports in the shoe enable circulation at all times, and the shoe can also have one or more backpressure valves, see Figure 7, which prevents the cement slurry from U-tubing, i.e. heavy cement forcing lighter cement or mud up the shoe track. The entire shoe is made of material which is easy to drill through. This makes it easier to start drilling the next section. However, since this thesis is considering reservoir liners, the drillability of the shoe is not of the outmost interest.

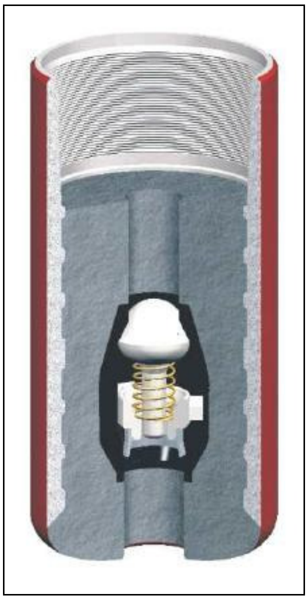

Figure 6: Float shoe (courtesy of Weatherford)

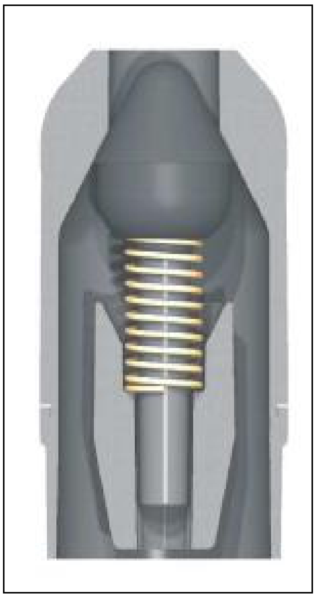

Figure 7: Backpressure valve (courtesy of Weatherford)

A reamer shoe can be run instead of a float shoe if the hole is suspected to have restrictions or ledges. In addition to having the same functions as the float, a reamer shoe possess the ability of reaming the wellbore while running in hole with the liner string.

Both float and reamer shoes are available with eccentric noses, only composite material, designed to overcome obstructions often present in horizontal or highly deviated wellbores, wells with varying internal diameters, or wells that are being sidetracked, see Figure 8.

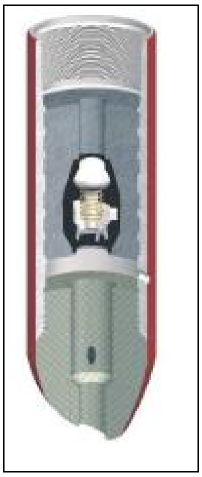

Figure 8: Composite eccentric nose (courtesy of Weatherford)

The float collar, as shown in Figure 9, is placed above the float shoe, often one or two joints above, but depending on the shoe track design it could also be farther up. The float collar is basically a backpressure valve, acting as a backup for the valve in the shoe.

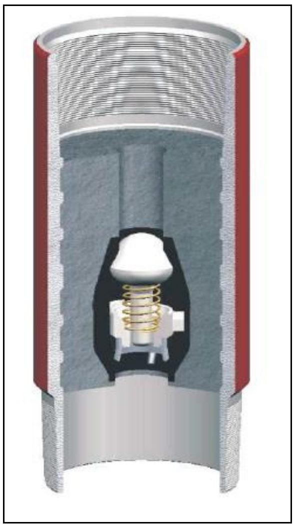

Figure 9: Float collar (courtesy of Weatherford)

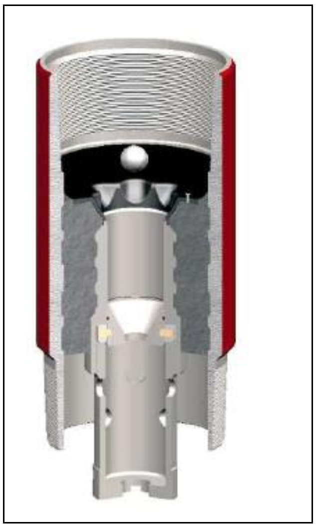

Figure 10: Landing collar with ball catcher (courtesy of Weatherford)

The landing collar is placed some joints over the float shoe. The main function of the landing collar is to catch displacement plugs and the ball, see Figure 10. In addition it also acts as a backup to the valve(s) in the shoe and the float collar.

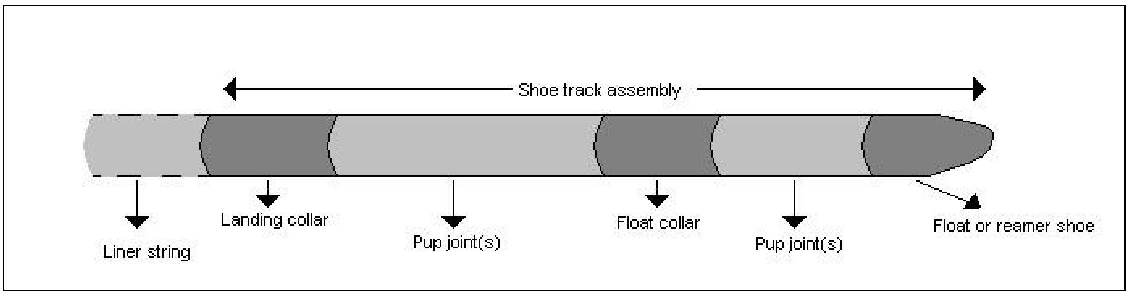

Figure 11: Schematic of shoe track assembly

1.2.4 Displacement plugs

To avoid contamination of the cement slurry by the drilling mud, one or more displacement plugs are normally used in a cement job. In a conventional casing cement job the displacement plugs are dropped from the surface, and this is still a feasible solution if the drill string on which the liner is run has a larger inner diameter, ID, than the liner. However, this is only possible for small liner sizes and in most cases when applying a liner solution the drill string has a similar ID to, i.e. lower or very close to, the inner diameter of the liner. Then, dropping the displacement plug from surface is no longer an option. Instead, drill pipe darts is dropped from the cement head. These darts are pumped down the drill pipe separating the spacer (or mud) from the slurry. After the wanted volume of cement slurry is pumped, a second dart is dropped and the well is displaced back to mud (or another fluid).

Figure 12: Standard cementing plugs (courtesy of Weatherford)

When entering the liner top area with the first dart, the dart latches into a plug which slides down inside the liner when the cement is pumped. The same happens with the dart pumped after the slurry. When using darts the displacement plugs is known as liner wiper plugs, as shown in Figure 12, and both plugs land in the landing collar.

Another approach to separate the fluids during a cement job is to use only darts. The objective is the same, but instead of latching into a plug the dart itself keep the fluids from commingling. Like plugs, the darts will also land in the landing collar. Using a dart system is only possible if the inner diameters of the running string, i.e. drill pipe, and the liner are in the same range. The main benefit of using darts is that it is a simpler system, i.e. less equipment and mechanisms involved, which reduces the risk of failure. However, if the difference in diameter is too large, using wiper plugs are the best solution.

1.2.5 Centralizers

Especially in longer and often high-angle wells getting enough standoff has proven to be a challenge. The main objective of having centralizers as part of the liner string is to provide the necessary standoff. The standoff value or ratio is a measure which tells if the string is centralized or not. Having a good standoff ratio is beneficial for both mud removal and displacement of cement as it improves the flow on the low side of the string. The American Petroleum Institute, API, have presented an equation for calculating the standoff ratio (API 2004).

Assuming a quality borehole and a perfectly centered casing, the annular clearance can be calculated from

$$l_a = \frac{D_W - D_P}{2} \qquad \textbf{(1-6)},$$

where
l_a is the annular clearance in feet,
D_W is the wellbore diameter in feet, and
D_P is the casing (or liner) outside diameter in feet.

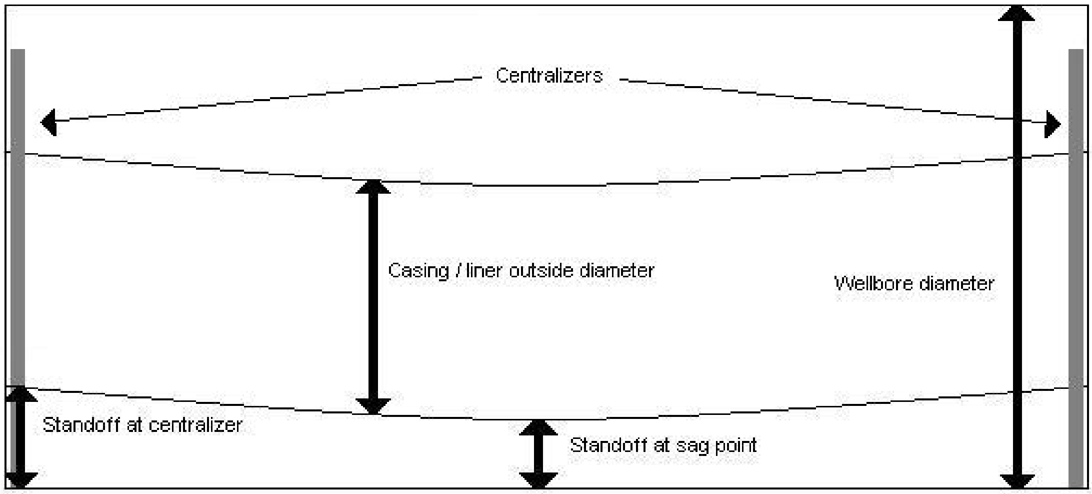

Figure 13: Calculation of casing (or liner) standoff in a wellbore

In Figure 13 a section between two centralizers of a horizontal casing (or liner) is shown. The standoff at the centralizer, S_C, and the standoff at the sag point, S_S, is both measured in feet. API 10D-2 (2004) stated that the minimum standoff, S, can occur either at the centralizers or at the point whit maximum deflection, i.e. the sag point,

$$S = \min(S_C ; S_S) \qquad \textbf{(1-7)}.$$

The final standoff ratio is then calculated using

$$R_S = \frac{S}{l_a} \cdot 100 \qquad \textbf{(1-8)},$$

where
R_S is the standoff ration expressed as a percentage,
S is the minimum standoff in feet, and
l_a is the annular clearance in feet.

A value of 100% signifies that the pipe is perfectly centered in the borehole, whereas a value of 0% means that the liner is laying (horizontal wells) or leaning (vertical wells) towards the wellbore wall. A rule of thumb in the oil industry is to keep the standoff value over a minimum of 75 %, whereas API reckons a ratio of 67 % as a minimum criterion for centralizers (API 2002).

Numerous types of centralizers are currently available in the market, ranging from the simple bow-spring type to the high-tech torque and drag reducing type. The type and number of centralizers needed to provide sufficient standoff for a given liner string are dictated by the well path, among other factors.

1.3 Preparations in front of the cement job

To have a good cement job, the following steps are of the highest importance:

1. Wellbore stability studies including analysis of:
   - rock mechanics,
   - the compaction if this is a problem (as on the Ekofisk field), and
   - how to avoid "trouble" zones.

2. Drilling including how to:
   - ensure a stable hole with no cavings, washouts, and cuttings,
   - have a good overview of drilling parameters, i.e. not to drill too fast, and
   - ensure sufficient cutting transport capabilities.

3. Mud Removal prior to cementing:
   - circulate and clean well thoroughly while drilling and afterwards,
   - remove filter cake with spacer(s), reducing the risk of having channeling, and
   - torque limitations.

4. Pumping cement and displacement of mud including:
   - pumping cement and displacement of mud,
   - ensuring not too large pressure drops in string and annulus,
   - pipe movement, and
   - torque limitations.

1.3.1 Wellbore Stability Studies

Getting a long lasting cement sheath between the liner and formation is a complex process which is depending on various factors. First of all, a hole has to be drilled to the wanted target. Careful planning and knowledge sharing between the drilling engineers, geologist, geophysicists, and reservoir engineers is a key factor in reaching this target. Since most of the production wells on the Ekofisk Field today are either slot recoveries, i.e. sidetracks, or new wellbores drilled in areas where the reservoir and overburden is fairly familiar, trouble zones with high stresses or fractures should be possible to avoid with proper planning.

1.3.1.1 Rock Mechanics

When drilling a well it is necessary to keep the mud weight, and hence the hydrostatic pressure, between the pore pressure and the fracturing pressure of the formation. The window between the pressures is known as the drilling margin, Figure 14, and this will also come into play when cementing the production liner.

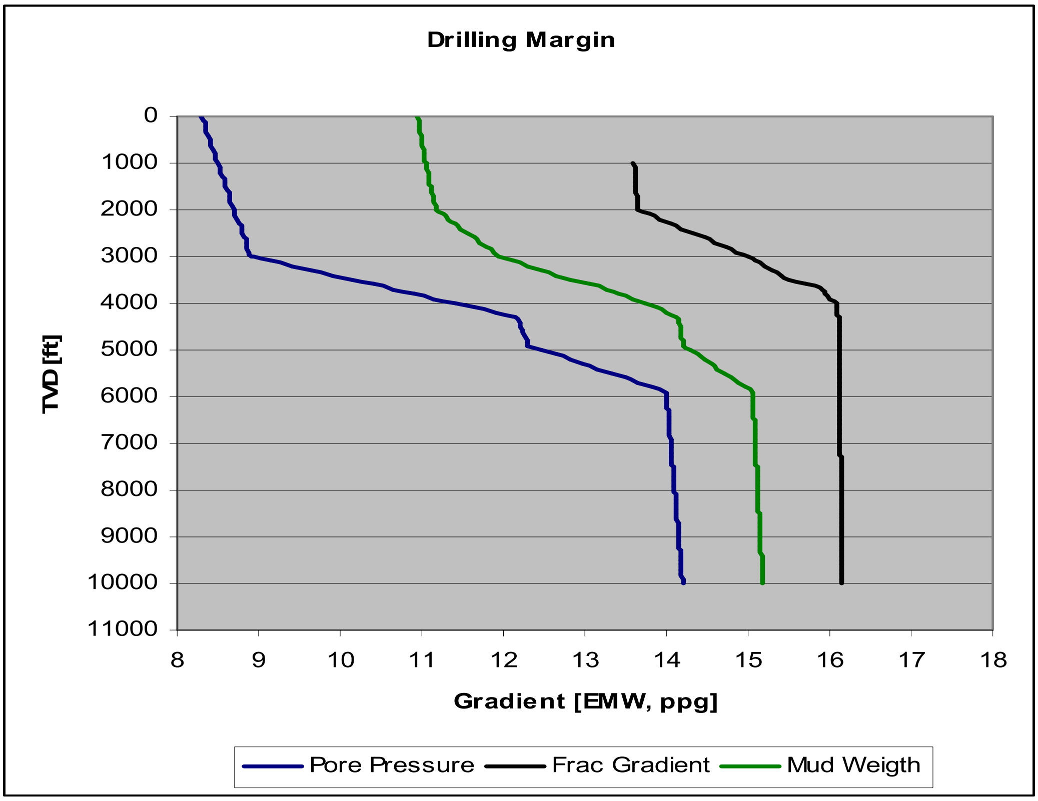

Figure 14: Drilling Margin

The fracturing pressure is the highest pressure the formation can take without yielding. If the pressure in the well exceeds the fracturing pressure, a crack will be formed in the formation and the well fluid will be drained from the well. This phenomenon is known as lost circulation. If too much fluid is lost during drilling, the velocity of mud in the annulus will be reduced and, hence, the lifting capability of the mud is lowered.

The pore pressure is basically the fluid pressure found in the pores. Often these pores are filled with formation water, and the pressure is normally given by:

$$P_P = \rho_{FW} \cdot 0{,}052 \cdot TVD + P_{SB} \qquad \textbf{(1-9)}$$

where
P_P is the pore pressure in psi,
P_{FW} is the average density of formation water in lbs/gal (density often increases with depth),
TVD is the true vertical depth in feet, and
P_{SB} is the pressure at seabed in psi.

Having a lower mud weight in the well than the pore pressure, i.e. being underbalanced, will allow the formation fluid to migrate into the wellbore. When drilling the reservoir section prior to setting the reservoir liner, the inflowing fluid will normally reduce the weight of the mud which can cause an uncontrolled well situation like a kick.

The mud weight curve in Figure 14 is calculated using the midline principle for illustration only. In practice the mud weight will normally not change according to the curve shown.

During the cement job it is important to maintain a hydrostatic pressure that does not exceed the formation fracturing pressure (Mueller et al. 1990). If the pressure is higher, loss of slurry will occur. The consequences of lost circulation may include:

- an incomplete or absent cement sheath across a zone of interest,
- a bridging of the annulus and subsequent flow restriction, or
- catastrophic job failure.

Among the consequences of having too low pressure during cementing are:

- leaking liner hanger seal which may give a kick, and
- inflow of pore fluid which may contaminant or channel through the cement sheath destroying its pressure isolating properties.

1.3.1.2 Compaction of the Ekofisk Field

Today, the reservoir compaction leading to field subsidence is a well known phenomenon, and compensating measures like jack-up of the facilities and continuous water injection has proven successful.

The seafloor subsidence in the Ekofisk field is a consequence of the reservoir compaction caused by production. Hydrocarbons are drained causing the reservoir pressure to decline. As a result, the effective stress on the rock will increase leading to the compaction (Johnson et al. 1989). The effective stress on the rock is defined as the difference between the overburden load on the rock and the pore pressure within the rock.

Bickley and Curry (1992) explained how the rock matrix must carry the weight of the overburden when the pore pressure is reduced. The result is that the rock matrix starts to compact in order to support the entire weight of the overburden.

1.3.2 Drilling

When drilling, a mud with sufficient viscosity and carrying capabilities should be used to ensure hole cleaning and transport of cuttings to the surface. The rate of penetration, ROP, the equivalent circulating density, ECD, the pump rate, and the revolutions per minute, RPM, all needs to be monitored closely. Too high ROP will be disadvantageous for the removal of cuttings and give a significant increase of ECD, especially if the pump rate is low. A high ROP implies that large amount of cuttings are produced, and to avoid packing off, i.e. plugging the wellbore, the BHA, or other parts of the drill string, the pump rate has to be sufficiently high to transport all the cutting to surface. The increase of ECD is a result of having more cuttings in the mud which increases the average density. RPM can also affect hole cleaning if not monitored as RPM is a central factor in transporting cuttings in deviated wells i.e. having a low RPM is not beneficial. After reaching the total depth of the well, TD, a period of circulation is wanted to make sure of that the hole is free of, or at least has a minimum of cuttings left in the well.

In the recent years, a wide variety of mud(s) are available on the market. Most of them are designed and tuned to meet different requirements, but for most practical purposes, there are only two different types of mud:

- oil based mud, OBM, and
- water based mud, WBM.

An oil based mud has oil as the continuous phase and usually may contain droplets of water, whereas water based mud has water as the continuous phase and usually may contain droplets of oil (Skaugen 1997).

When drilling the reservoir prior to installing the reservoir liner OBM are used to minimize the formation damage. Other benefits are:

- less friction,
- lubrication,
- good temperature tolerance, and
- reduced torque.

Mud has numerous functions while drilling and preparing for displacement and cementing. Among the most important are to:

- balance the pressure,
- clean the wellbore,
- cool, clean, and lubricate the bit,
- transport cuttings, need sufficient viscosity,
- suspend cuttings during stops in circulation, need sufficient gel strength,
- reduce friction,
- form a filtercake over the permeable zones preventing the mud from going into the formation, and
- provide communication between BHA and drilling engineer with mud pulses.

1.3.3 Mud Removal prior to cementing

After the drilling phase is completed, the mud removal process is commenced. This process is a key element in getting a good cement sheath bond between the liner and the formation. First, the mud is conditioned which means that the well is circulated and cleaned. This is started when the BHA is still at bottom and continues while pulling the drill string out of hole.

After the drilling assembly is out of hole, the liner is made up and run in hole while continuing conditioning the mud. When the liner shoe has reached the desired setting depth, the mud is circulated and conditioned before one, or several, spacer(s) are pumped in front of the cement to remove the mud cake. A spacer is a viscous fluid designed to remove the drilling mud and separate the mud from the cement, thus enable a better cement job. The cement is pumped right behind the spacer(s) and displaced in the annulus.

The mud removal efficiency is strongly dependent on a high quality borehole (Nelson and Guillot 2006). Among the attributes contributing to such a borehole are:

- controlled subsurface pressures,
- a smooth hole with only minor doglegs,
- in-gauge hole diameter as given by the bit size,
- a stable and clean hole, and
- thin filtercakes over the permeable zones.

Torque considerations for the liner and running string are included in chapter 1.4.

1.3.4 Pumping cement and displacement of mud

Finally, the cement itself must be designed to meet the requirements dictated by the reservoir. After deciding what cement slurry to pump, a minimum standoff value of 75 % is needed to better the chances of getting the slurry around the entire annulus between liner and formation. In horizontal or highly deviated wells, means to reduce the forming of channels due to free water on the high side also has to be taken into consideration. Both proper centralization and having no free water in the cement slurry increases the chances of getting a good cement job. A good cement sheath covering the entire annulus is beneficial for zonal isolation because it will stop reservoir fluids from migrating through channels.

Pipe movement is discussed in chapter 2.5 and torque limitations in chapter 1.4.

1.4 Torque when running and cementing liner

To aid mud removal and to get full coverage of cement, movement of the string is always a goal. Torque simulations are therefore performed before running the liner. Within these simulations centralizer placement and standoff ratio are integral elements.

When running liner on drill pipe, the weak point when it comes to torque can either be the:

- liner,
- liner hanger,
- running tool,
- drill pipe,
- saver sub, or
- top drive system, TDS.

The top drive system may provide a torque up to 100 kft-lbs (Maersk 2002). In practice this means that the torque limit will never be on the TDS.

There are two main reasons for using a saver sub. First, using a saver sub limits the connections made up directly on the threads on the TDS which limits the wear. Second, the saver sub can be changed depending on the pipe or casing size and threads, hence act as a crossover. A normal saver sub used when running 6 5/8'' liner on 5 1/2'' drill pipe has a make-up torque of 34.55 kft-lbs.

Often the running string consists of more than one type of drill pipe due to pipe available on the rig. A typical scenario is to have two different types of pipe, e.g. 5 ½'' pipe weighing 24.7# and 5 ½'' pipe weighing 21.9#. The torque limit for the heaviest pipe is 38.3 kft-lbs, whereas the lighter pipe can take 34.55 kft-lbs of torque. Since the torque decreases towards the bottom end of the liner string, the heaviest pipe will be run in the upper part of the running string since this section will experience the highest torque values.

The running tool connects the drill pipe to the liner hanger, and is released from the hanger by pressure when setting the slips. This is true for conventional liner hangers. For expandable hangers a set of pins are sheared by putting down weight to release from the running tool. A set of shear screws set to break at for instance 28 kft-lbs puts a limitation to the torque for the running tool and liner hanger.

The torque limit for the liner string depends on the strength of the connections. For a 6 5/8'', 65.8# liner the target make-up torque is 25 kft-lbs (Tenaris 2009), hence, this will also be the torque limit.

The torque at a given point in the string will be the cumulated torque from bottom of the string to that point. This means that the torque will increase with length, implying that the maximum torque will be at surface when having the liner at TD, hence the weak point will be either at the top of the drill pipe, or possible at the top of the liner if the liner connection requires less make-up torque than the drill pipe connection. Having a stronger or heavier drill pipe will raise the torque limit, but this is not beneficial for drilling, i.e. the pipe becomes to stiff. Since most offshore rigs do not have capacity for having several types of drill pipe onboard, the operators often choose to use the pipe best suited for drilling both for drilling and running the liner.

2 Parameters affecting the success rate

Various parameters can affect the outcome of foam cementing the reservoir liner. Some of them are mention in this chapter, including:

- well design,
- pumping parameters,
- liner properties,
- cement properties, and
- liner movement.

2.1 Well Design

The well profile will often affect the performance when running in hole with a liner. Factors that may come into play are:

- inclination,
- azimuth, and
- dog-leg severity, DLS.

In the petroleum industry, the wellbore inclination is defined as the angle measured relative to the vertical direction, Figure 15. Thus, a vertical and horizontal well will have an inclination of 0 ° and 90 ° respectively.

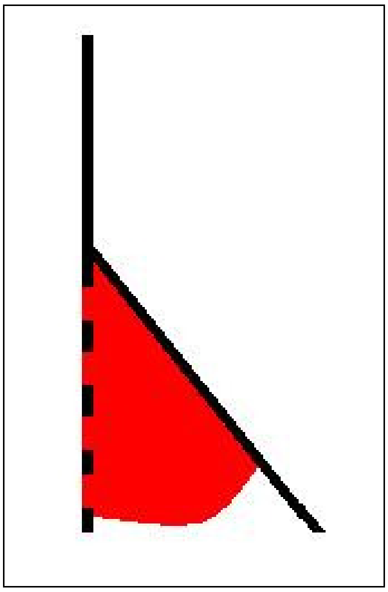

Figure 15: Inclination

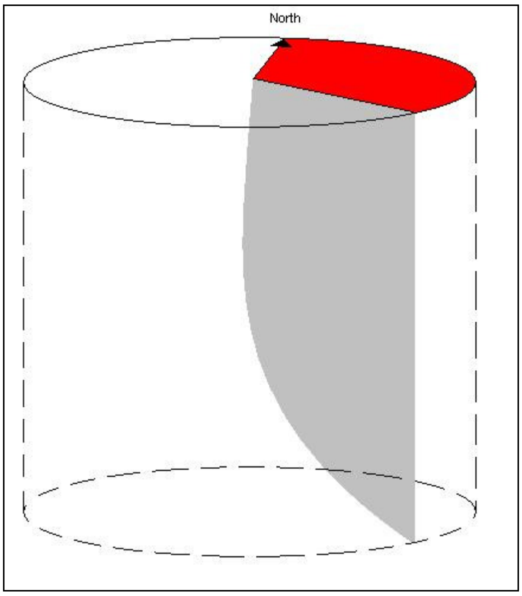

Figure 16: Azimuth

Azimuth is defined as the angle between true or magnetic north and the vertical projection of the wellbore, measured clockwise from north, Figure 16. A drilling engineer determines the azimuth from directional surveys, measured in degrees from the geographic or magnetic north.

Inglis (1987) defines a dog-leg as an abrupt change in hole angle or direction that causes a sharp bend in the wellbore. The amount of bending, i.e. the severity of the dog-leg, is expressed as the change in angle per 100 feet, given by

$$DLS = 100 \cdot \frac{\phi}{L} \qquad \textbf{(2-1),}$$

where
DLS is the dog-leg severity in º / 100 ft,
Φ is the dog-leg angle in º, and
L is the well path length between the measured positions along the well.

Inclination, azimuth and DLS will all contribute to the curvature of the wellbore, and depending on the design, they will affect the liner run, and potentially the cement job. A smooth, near vertical well will put minor restrictions to the running and cementing of the liner, whereas getting a sufficiently good cement job on a horizontal well with high DLS will be more difficult.

2.2 Pumping parameters

The pumpability of cement may have a major impact on the success of the operation. First, the circulating rate has to be suited to the formation in a manner that will disturb the formation the least. If the formation has a low fracture gradient the rate has to be kept fairly low so that the risk of fracturing the formation is minimized. The consequence of fracturing the formation is losses which makes it harder to achieve the desired cement coverage. However, the pump rate is generally kept as high as possible to remove mud and filter cake from the annulus in order to reduce channeling.

ECD is also coming into play when pumping cement and this will affect the pump rate. Like mud, cement has also a static density and an effective density, i.e. ECD, when circulating. ECD, for mud, is the sum of the mud weight and the hydrostatic contribution given by:

$$ECD = MW + \frac{\Delta P}{0{,}052 \cdot TVD} \qquad \textbf{(2-2)},$$

where
ECD is the equivalent circulating density in ppg,
MW is the mud weight in ppg,
ΔP is the pressure drop in the annulus between surface and the depth in psi, and
TVD is the true vertical depth in feet.

The ECD for cement is calculated in the same way, and like circulating rate it is important to design the cement slurry so that it will not fracture the formation while displacing.

When designing the cement job, the circulating time is one of the factors considered. The circulating time is the period from the cement is mixed till it is no longer pumpable, i.e. the cement has started to develop strength. This period has to be long enough to pump and displace the wanted volume of cement, but also short enough to start developing strength when placed in the annulus.

2.3 Liner properties

Several properties of the liner itself are putting restrictions or limitations on the running of liner. Among these are:

- the length of liner,
- the weight of the liner
- the diameter of liner, and
- the torque limitation.

The length of the liner is dictated by the wellbore that is being drilled, ranging from hundreds to thousands of feet. In general, a shorter liner is easier to manipulate than a longer liner during the cement job provided the same well parameters as it is shorter and weighs less.

The diameter of the liner is one of the attributes contributing the most to the friction factor. Since well production is a function of liner diameter, having a liner with large diameter is beneficial. On the other hand a liner with smaller diameter will in general be easier to cement due to larger annular clearance between the wellbore wall and the liner. Obviously this is true only if the smaller liner is run and cemented in a hole with the same diameter as the larger liner.

The torque limit for liners has been discussed in chapter 1.4, and will not be discussed any further. However, it is obvious that the liners ability to withstand torque is a central factor when it comes to getting a good cement job as long as liner movement, i.e. rotation, is regarded as a key element.

2.4 Cement properties

The cement is engineered and tested to meet the conditions in each wellbore. Various attributes of the cement will affect the pumping and displacement of cement. Among those are:

- density of cement,
- foam quality,
- permeability,
- compressive strength, and

- friction.

The density of conventional and foam cement have been discussed in chapter 1.1.1 and 1.1.2 respectively, and one of the main advantages with using foam cement is that it is easy to adjust the density by varying the nitrogen rate. In turn, the nitrogen rate will affect the foam quality if the volume of un-foamed slurry is kept constant. The foam quality was also discussed in chapter 1.1.2.

The requirements of having a set cement with low permeability and high compressive strength are some of the key properties were foam cement outperforms conventional cement. These advantages of foam cement were discusses in chapter 1.1.3, and is beneficial for zonal isolation and reservoir compaction.

Foam cement have the ability to reduce torque while rotating the liner (ConocoPhillips 2004), thus reduce the friction compared to using conventional cement.

2.5 Liner movement

Movement or manipulation of the liner while pumping and displacing is a key factor when performing a cement job. A liner string can be manipulated either by rotation, reciprocation or a combination of both, see Figure 17 and Figure 18.

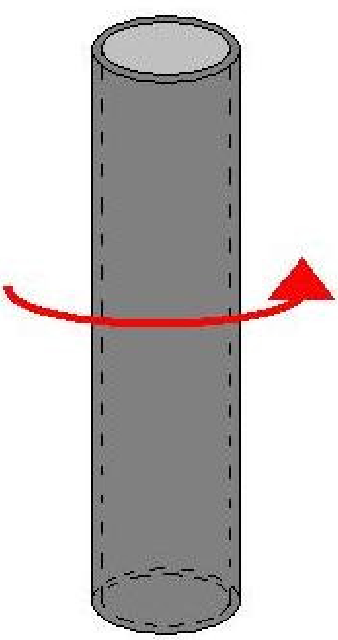

Figure 17: Rotation of liner

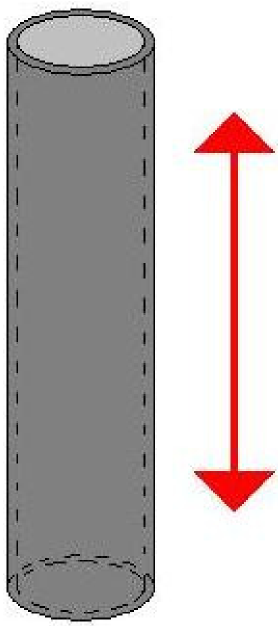

Figure 18: Reciprocation of liner

Over the years, several papers have been written on liner movement. Turcich and Goad (1981) reported that over 100 liners had been successfully reciprocated while displacing to cement in the Prudhoe Bay Unit. Further, a study by Landrum et al. (1985) concluded that if a liner is not manipulated, the frequency of remedial operations increases compared to liners cemented while moving the liner. This study also stated that rotation was preferred over reciprocation, thus eliminating the risk of getting stuck high or at top of a stroke during reciprocation. A paper by McPherson (2000) tells about the benefits of moving the pipe, i.e. rotate the pipe, in front of and during a cementing operation. Among the benefits are cuttings and filter cake removal, and breaking down mud gel.

The liner movement during pumping and displacing the cement depends on the liner hanger chosen. If a conventional hanger is used, the slips are set prior to the cement job, and only rotation will be possible during the displacement. An expandable hanger is not set until the cement is in place, allowing both rotation and reciprocation of the string during the job.

3 Potential Problems

Numerous problems may occur when running and cementing reservoir liners, including:

- problems when running in hole with the liner,
- problems when cementing the liner, and
- other problems.

3.1 When running in hole with the liner

Obviously, friction can become an important factor when running a liner, both inside casing and in open hole. Friction may impact the rotation performance, and too high friction can result in that the torque limit is reached. If that is the case, the rest of the liner cement operations have to be completed without being able to rotate.

The torque limit can also be reached if there is large amount of cuttings in the well. In highly deviated or horizontal wells the cuttings will form a bed on the low side which may cause the liner string getting mechanical stuck.

3.2 When cementing the liner

When cementing a liner, especially in highly deviated or horizontal wells, a major challenge is to get the cement to cover the entire annuli. Often there may be some cuttings remaining on the low side, insufficient mud removal, or free channeling of water on high side, Figure 19. Independently, or combined they can all result in a poor cement job.

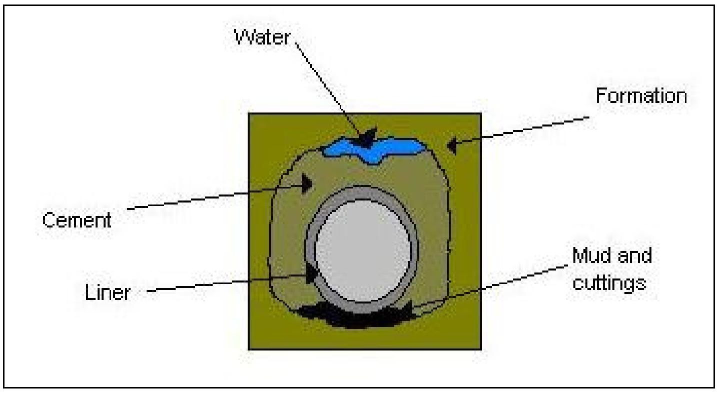

Figure 19: Problems when cementing liner

3.3 Other

Hole enlargement of the reservoir section with a reamer is often regarded as a benefit since a larger hole implies higher clearance when running and cement the liner. Thus, the chance of getting a better cement sheath should be improved. However, making a larger diameter also involves more cuttings, and if they are not transported out of hole they may cause problems like packing off the liner. Reaming will also take extra time in addition to the time spent to drilling, and the more time spent with tools and / or equipment in the well, the higher probability there is of getting into trouble.

In sum, reaming may be beneficial but can also result in serious problems.

4 Presentation of Data and Results

Data from the foam cement jobs of the 32 reservoir liners are included and used as a basis for the evaluation of the cementing operations. A success criterion is established to define the outcome of the different jobs. Further, a number of case studies are included and finally some statistics are presented.

4.1 Ekofisk 2/4 M

A variety of different data concerning the foam jobs on the Ekofisk M are gathered to have a basis for the evaluation, see appendix A-1 – A-3. Among those are:

- directional data,
- liner size and length,
- pipe movement readings,
- UTM coordinates, and
- comments regarding the pumping and displacement of cement.

4.2 Success Criterion

To say whether a reservoir liner cement job was successful or not can be a tough challenge. Many aspects come into play, and most of them are near impossible to verify the result of. Among the factors contributing are:

- centralization,
- zonal isolation, i.e. have a good cement sheath across the zone of interest,
- outcome of primary cement job, i.e. is a remedial job needed, and
- liner movement, i.e. rotation.

To be able to establish a success criterion each of the factors and what it takes to achieve success for that factor will be discussed individually. However, this must not be confused with the final success outcome.

Different types of centralizers and how they provide sufficient standoff values have been discussed in chapter 1.2.5. However, proper centralization is hard to confirm when running and cementing the liner. In turn, the possible lack of standoff can lead to an insufficient cement sheath between the liner and the formation causing channeling. For conventional cement a CBL can be performed to check the quality of the cement, but when using foamed cement it is harder to confirm the coverage of cement around the liner. The reason for this is that foamed cement and mud have almost the same specific gravity which makes it harder to see the contrast from the log, but with the right set up and tuning of the logging tool it is possible. However, the thick walled liners used are the main reason for not having a good log as the liners will reduce the signals sent out from the logging tool, thus reducing the range and quality of the log.

Looking merely on the outcome of the primary cement jobs, the job can be defined as a success if there is no need for a remedial cement operation.

On of the easiest criterions applied for determining a success is pipe manipulation. Since rotation of the liner is believed to be a key element in order to get cement around the entire liner, the cement job is regarded a success if the liner is rotated throughout the displacement. However, a good cement job can be achieved without manipulating the pipe which makes the pipe manipulation criteria on its own inconsistent.

Based on the discussion in this chapter, the following criterion is decided on: The cement job is a success if liner manipulation is maintained throughout the job and no remedial cement job is needed. However, if liner manipulation is maintained for most of the job and no remedial cement job is needed, the job is defined as a semi-success. By the term *for most of the job* it is meant a) rotation has to be regained after setting the hanger (valid for hangers normally set prior to displacing the cement), or b) rotation has to be maintained until most of the cement is displaced (valid for hangers normally set after displacing the cement). If the job does not fall into one of these two categories it is defined as a failure.

4.3 Case studies

The 2/4 Ekofisk Mike has 30 slots. All of them have been drilled, and some have also been sidetracked for various reasons. This means that 32 reservoir liners have been cemented over the past 4 years. Most of them, 26, have a 6 5/8'' liner, 2 have 6 5/8'' crossed over to 5 ½'' liner, and the last 4 have a 5'' liner, see Figure 20.

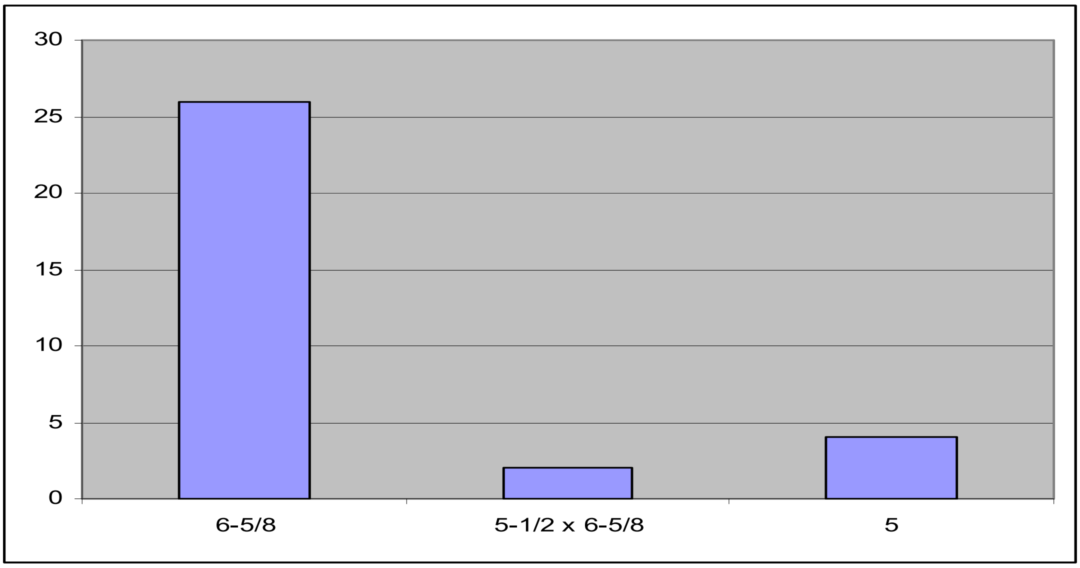

Figure 20: Numbers of reservoir liners installed by size

4.3.1 Case 1: M-1A

M-1 was originally intended to be a deviated Ekofisk and Tor producer, but due to a wet reservoir section, the well was plugged back and sidetracked. Thus, the well was drilled to the contingency target, making M-1A a horizontal upper Ekofisk producer, see appendix B-1 for directional data.

The 10'' liner shoe is at 12365' MD, and a 8 ½'' hole is drilled to 15996' MD, or 10307' TVD. The plan was to drill further, but due to loss of returns, initial loss rate is 75 bph, 15996' MD was called TD, see appendix B-2 for bit report and B-3 for hole cleaning information. The section was drilled in three runs, experiencing one bit and one steering failure in the 8 ½'' section. As a consequence of the losses at TD, hole cleaning is limited. Nevertheless, several LCM pills are spotted to cure the losses and the well was circulated bottoms up at low rates.

The 6 5/8'' liner was run in hole. Prior to tagging TD the liner was rotated with 10 RPM and 22-25 kft-lbs. A simulated torque of 32.907 kft-lbs indicates that rotation might be difficult. However, the simulation is based on TD at 17830' MD, and not at 15996' MD which is the case due to losses. Based on the simulation, and the new TD, rotation is feasible. The length of the liner is 4666'.

Prior to setting the liner hanger, a major weight drop was experienced, indicating that the running tool was free from the liner. However, when rotating the string to verify if the running tool was free or not, the string stalled out at 30 kft-lbs indicating that the running tool was still attached to the hanger. Therefore the liner hanger setting ball was dropped as normal prior to proceeding to the cementing phase.

Foam cement slurry was displaced with 3-4 bpm and 680 psi. The wiper plug was bumped with 2500 psi. A total of 28 bbls were lost during the entire cement job. The liner was not rotated after it stalled out prior to setting the hanger.

Based on the success criterion stated in chapter 4.2 the cementation of the 6 5/8'' liner in M-1A is not regarded as a success.

4.3.2 Case 2: M-3

M-3 is drilled as a deviated Ekofisk producer on the southwestern crest of the Ekofisk field, see appendix C-1 for directional data.

The 10'' liner shoe is at 10689' MD, and a 8 ½'' hole is drilled to 12210' MD, or 10858' TVD. The ROP were reduced from an average of 100.8 ft/hr to an average of 33.6 ft/hr, and finally 10.0 ft/hr when approaching TD to help hole cleaning, see appendix C-2 for bit report. The cumulative average ROP for drilling the 8 ½'' section was 51.1 ft/hr. Bottoms up circulation was performed with BHA inside 10'' liner.

To make sure that the hole was free from cuttings, the well was circulated bottoms up once more after tagging bottom with the 6 5/8'' liner. The torque simulation shows that the liner should rotate with a torque of 16.110 kft-lbs. The length of the liner is 2384'.

The liner hanger was set, and rotation was initiated. The rotation was kept throughout the job at 20 RPM and 14-18 kft-lbs, and full returns during pumping and displacement of the slurry was observed.

Based on the success criterion stated in chapter 4.2 the cementation of the 6 5/8'' liner in M-3 is regarded a success. Liner rotation was regained after setting the hanger, and full returns were maintained throughout the job.

4.3.3 Case 3: M-6 T2

M-6 T2 was drilled as a deviated Ekofisk and Tor producer in the northwestern crest of the Ekofisk field, see appendix D-1 for directional data.

The 10'' liner shoe is at 13257' MD, and a 8 ½'' hole was drilled to 14023' MD, or 10615' TVD. The section was drilled in two runs, see appendix D-2 for bit reports. The first bit was run as a cleanout assembly without MWD, and was only used for 89'. The second bit was used to TD with an average ROP of 24.0 ft/hr. Prior to coming out of hole with the drilling assembly the well was circulated bottoms up with 500 gpm and 2261 psi.

A simulation shows that the liner, with a length of 1408', can be rotated with approximately 21.3 kft-lbs of torque. The mud was circulated and conditioned while rotating the 6 5/8'' liner with 20 RPM and 16-19 kft-lbs at bottom. Rotation was stopped and the liner hanger was set successfully prior to start pumping the cement. Rotation was resumed and held at 20 RPM and 13-17 kft-lbs during the entire displacement. Some mud losses to the formation were experienced, and the well had approximately 75 % returns.

Based on the success criterion stated in chapter 4.2 the cementation of the 6 5/8'' liner in M-6 T2 is regarded a success. Liner rotation was regained after setting the hanger and a high rate of returns were maintained throughout the job.

4.3.4 Case 4: M-9

M-9 was drilled as a horizontal producer on the northeastern flank, see appendix E-1 for directional data.

The 10'' liner shoe is at 12649' MD, and a 8 ½'' hole was drilled to 16000' MD, or 10420' TVD. Some stringers where observed when drilling this section, but no other difficulties where encountered. The ROP was reduced from an average of 140.7 ft/hr to an average of 89.3 ft/hr when approaching TD to help hole cleaning, see appendix E-2 for bit report and E-3 for hole cleaning plot. On the way out of hole, the well was circulated bottoms up with 600 GPM with the BHA inside the 10'' liner.

The 6 5/8'' liner was made up and run in hole using 5 ½'' drill pipe (both 21.9 # and 24.7 #). Simulations done for the cement job indicates that it will be possible to rotate the liner with 24.976 kft-lbs. The length of the liner is 4505'.

After the bottom was tagged, the liner was pulled back to setting depth and the cement head installed. While circulating bottoms up rotation was initiated. The hanger was set by pumping down a ball and pressuring up. When it was confirmed that the hanger was set the top dart was released and pumping of cement was commenced.

The string stalled out after pumping 110 of the total 157 bbls slurry into open hole. The circulation rate for this job was initially 3 bpm and ended up at 6 bpm with the average of 4 bpm. Full returns were kept during entire job, and contaminated mud and spacer were seen at surface.

Based on the success criterion stated in chapter 4.2 the cementation of the 6 5/8'' liner on M-9 is regarded as a semi-success. Rotation was not maintained for the entire displacement period, but the return rate during the job and traces of cement in returns indicates a good job.

4.3.5 Case 5: M-15A

The original M-15 was sidetracked due to partly wet reservoir, and the new M-15A wellbore was drilled as a horizontal lower Ekofisk producer, see appendix F-1 for directional data.

The 10'' liner shoe is at 14262' MD, and a 8 ½'' hole was drilled to 18932' MD, or 10639' TVD. Due to the open hole sidetrack, the section was drilled in two runs, see appendix F-2 for bit reports.

While tripping out of hole, the well was circulated bottoms up with the BHA inside the 10'' liner. A second period of circulating bottoms up was performed after tagging TD with the liner. The hole cleaning graph, see appendix F-3, indicates a sufficient cleaning sequence.

The original wellbore was open hole sidetracked, and for some reasons there exist no torque simulation for the liner in the new well path. However, simulation done for the planned 6 5/8'' liner, length 7823', shows that the liner can be rotated with about 19 kft-lbs of torque if a high quality type of centralizers is used. If it is chosen to use a simpler type of centralizers for the lower part of the liner, the simulation indicates that nearly 34 kft-lbs of torque are needed to be able to rotate the liner.

Due to the results of the simulations, the length of the liner, 5928', and the long horizontal section, 2828' has an inclination above 85 º, it was decided to run a 6 5/8'' by 5 ½'' liner instead of the planned 6 5/8'' liner.

The liner was rotated prior to and during dropping the liner hanger setting ball. The hanger was set successfully by pressure, and liner string rotation was initiated. The rotation was kept at 20 RPM and 28 kft-lbs for the rest of the job. The displacement rate during the foam job varied between 9 and 4 bpm, and full returns were seen throughout the job.

Based on the success criterion stated in chapter 4.2 the cementation of the 6 5/8’’ by 5 ½’’ liner in M-15A is regarded a success. Liner rotation was regained after setting the hanger, and full returns were maintained throughout the job.

4.4 General Evaluation of Foam Cement Jobs

All the 32 foam cement jobs on the Ekofisk M field have been evaluated like the examples included in the case studies. The summary of all the foam cement jobs of the reservoir liner can be seen in Table 2.

		6-5/8			5-1/2 x 6-5/8			5		
Liner Length	#	Success	Semi-success	Failure	Success	Semi-success	Failure	Success	Semi-success	Failure
1000-2000	9	7	0	2	0	0	0	0	0	0
2000-3000	7	4	1	2	0	0	0	0	0	0
3000-4000	4	1	1	1	0	0	0	1	0	0
4000-5000	6	0	2	2	0	0	0	2	0	0
5000-6000	4	0	1	1	1	0	1	0	0	0
6000-	2	0	1	0	0	0	0	0	0	1
Total	32	12	6	8	1	0	1	3	0	1

Table 2: Summary of all foam cement jobs

The evaluation concludes that only 16 out of a total of 32 liners were successfully cemented, 6 of the liner cement jobs are regarded as semi-successful, and as many as 10 jobs are defined as failures, see also Figure 21.

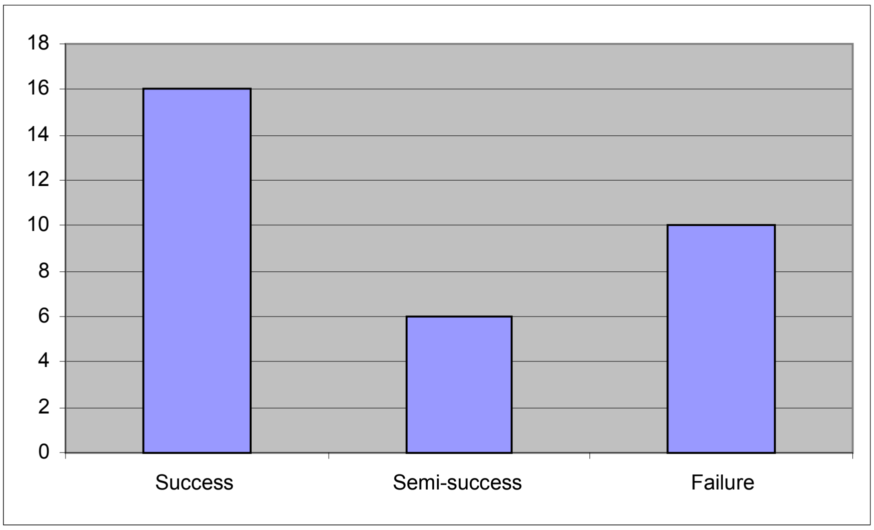

Figure 21: Outcome of reservoir liner foam cement jobs

The most common reason for failure is that the liner can not be rotated after the liner hanger is set. 7 out of 10 failures fall into that category. The last 3 failures are all one of a kind, including one incident where the liner string got stuck when positioning, one liner that needed a remedial cement job, and finally one operation where rotation had to be stopped after the cement head started to turn.

The 6 jobs defined as semi-successes all reestablished rotation after the liner hanger was set, but all stalled out before the displacement of cement was completed, i.e. they exceeded the torque limit for rotating the liner string. However, all of the semi-successes had fairly good return rate during the entire cementing process implying that the outcome of the operation could be sufficient despite not being able to rotate throughout the job.

4.4.1 Outcome for different liner sizes

In Figure 20 the number of different liner sizes is shown. If the success criterion, as defined in chapter 4.2, is applied, the outcome for the different sizes is shown in Figure 22.

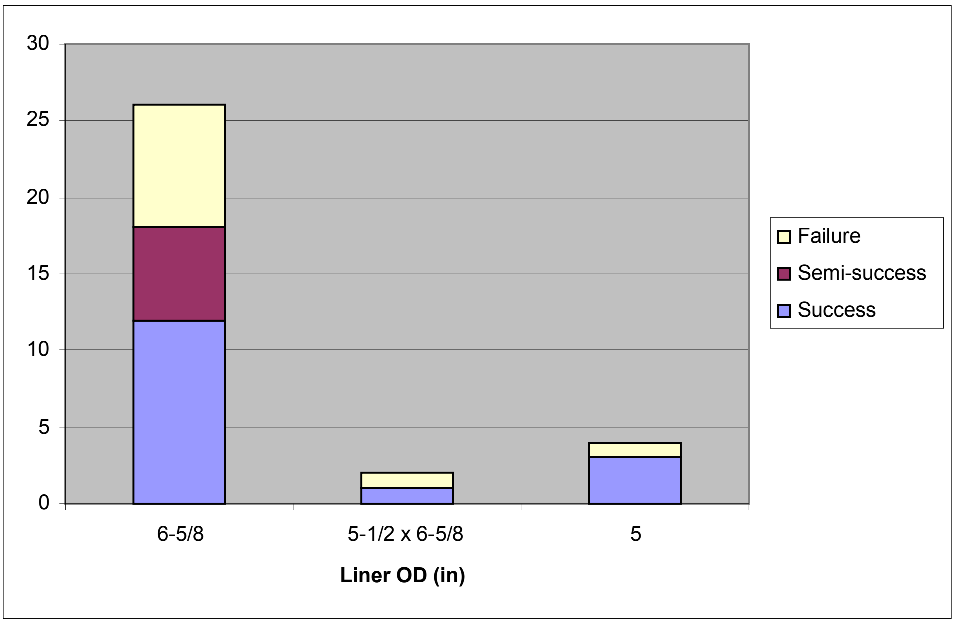

Figure 22: Outcome of cement job for the different liner sizes

Out of a total of 26 wells completed with a 6 5/8'' liner, 12 were regarded as successes, 6 as semi-successes, and 8 as failures. Only two wells have the 5 ½'' crossed over to 6 5/8'' liner solution, one of them was a success and the other one ended up as a failure. 3 of the 4 wells with the 5'' liner were successes, while the fourth is regarded as a failure.

The numbers in Figure 22 can also be presented as percentage as shown in Figure 23, where each liner size sums up to 100 %. From this figure it is possible to see the percentage of the different outcomes for each liner size.

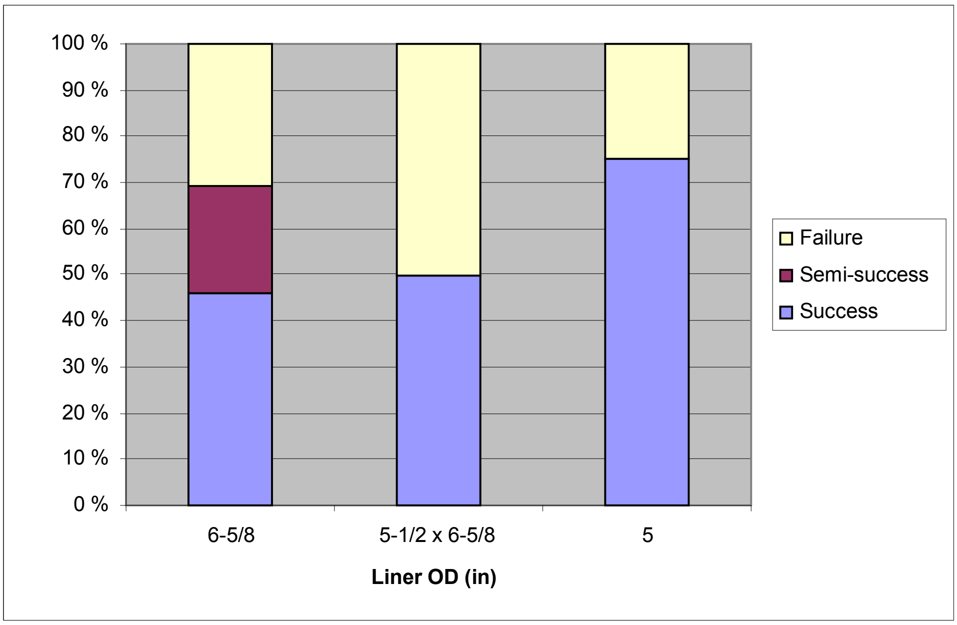

Figure 23: Percentage contribution for the different liner sizes

As Figure 23 shows only 46 % of 6 5/8'' foam cement jobs were successful, 31 % are regarded as unsuccessful, and 23 % fall into the semi-success category.

For the 5 ½'' crossed over to 6 5/8'' and the 5'' liner it is hard to say something about the percentages as the data basis is very limited, with only two and four liners respectively.

4.4.2 Outcome for different liner lengths

Depending on target, well type, i.e. horizontal or deviated, and anti-collision constraints the length of the reservoir section, and hence the length of the reservoir liner vary from well to well.

The average liner length of the 32 wells investigated is 3372', with a maximum length of 6463' and a minimum length of 1408'. In Figure 24 all the liners are grouped in intervals of 1000'. In addition, the different sizes are also shown in this figure. From the figure it is observed that 16 of the liners have a length below 3000', 10 liners have a length between 3000 and 5000', and the last 6 are longer than 5000'.

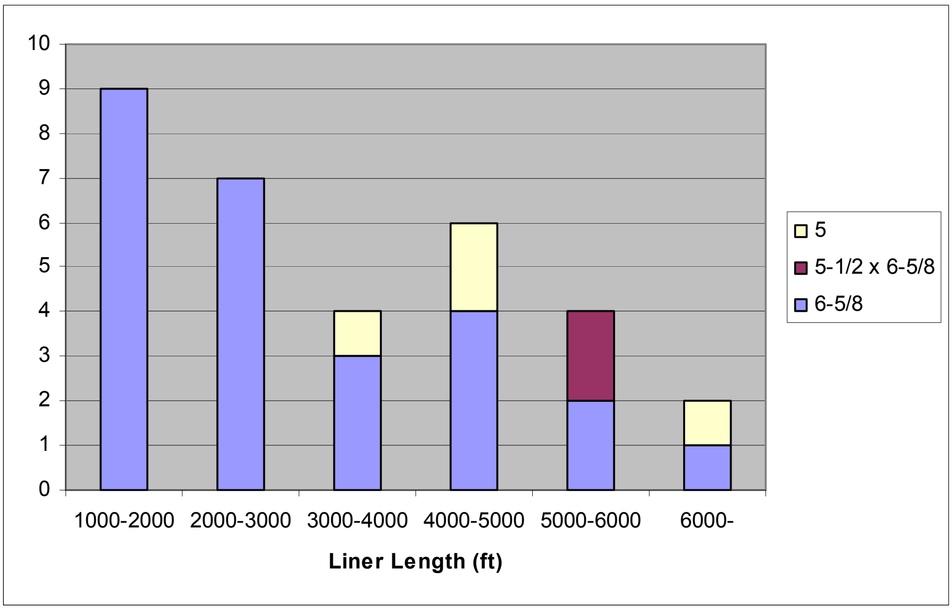

Figure 24: Liner length versus liner size

If the outcome is compared against the liner length a clear trend can be observed, see Figure 25. As the liner becomes longer, the percentage of semi-successes or failures increases.

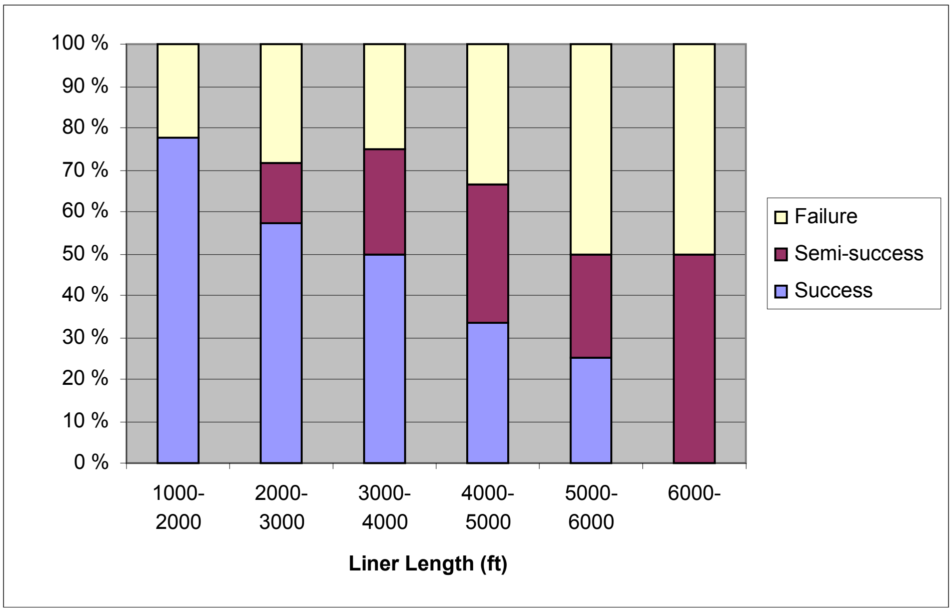

Figure 25: Liner length versus outcome

For the shortest liners, i.e. with a length between 1000 and 2000', the percentage for success is nearly 78 %, whereas the same percentage for liners with a length between 5000 and 6000' is only 25 %.

4.4.3 Reservoir target

A hypothesis investigated was whether the outcome of the foam cement job had any connection to the reservoir target. As discussed in chapter 1.3.1, the reservoir on the Ekofisk field has been examined carefully over the years, and the process is still ongoing. Using the knowledge and understanding of the field in the well planning process should not be a problem. Nevertheless, the option was investigated.

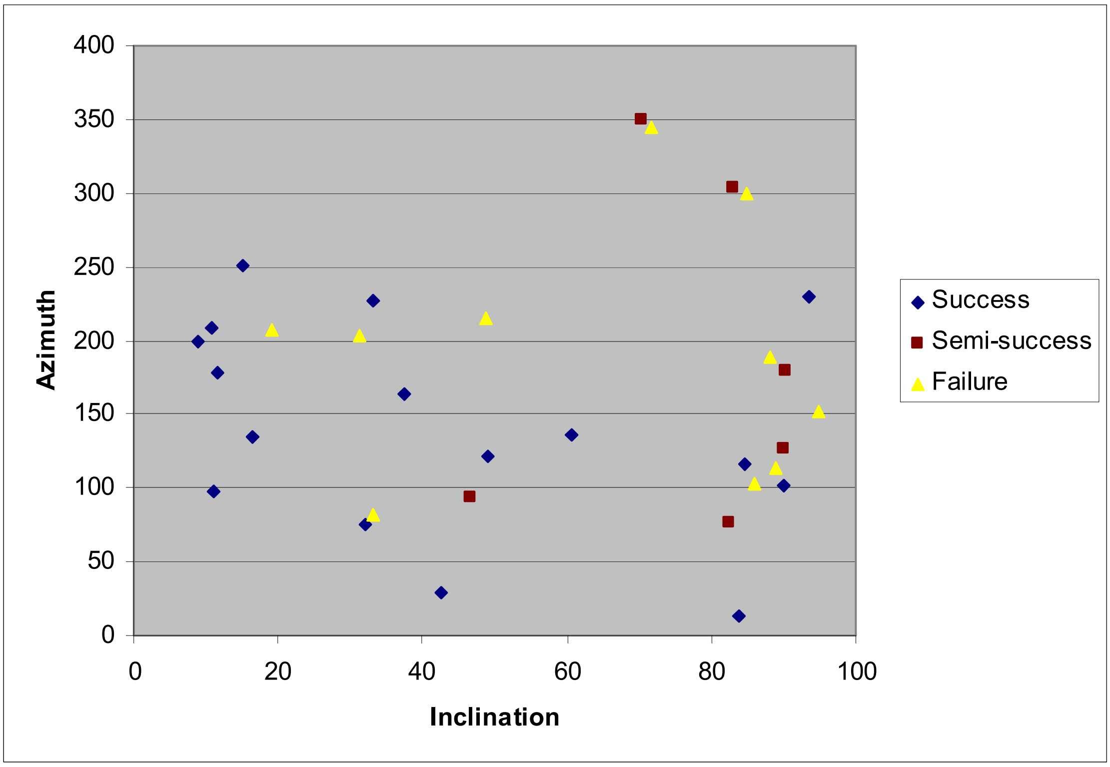

Figure 26: Azimuth versus inclination for the reservoir liner shoes

As a first attempt the inclination of the reservoir liner shoes were plotted against the azimuth, see Figure 26, but as the plot shows there is no apparent link between the two values. Therefore the UTM coordinates for the liner shoes were plotted. As seen in Figure 27, the outcome of the cement process varies, and no obvious pattern can be observed from the shoe coordinates.

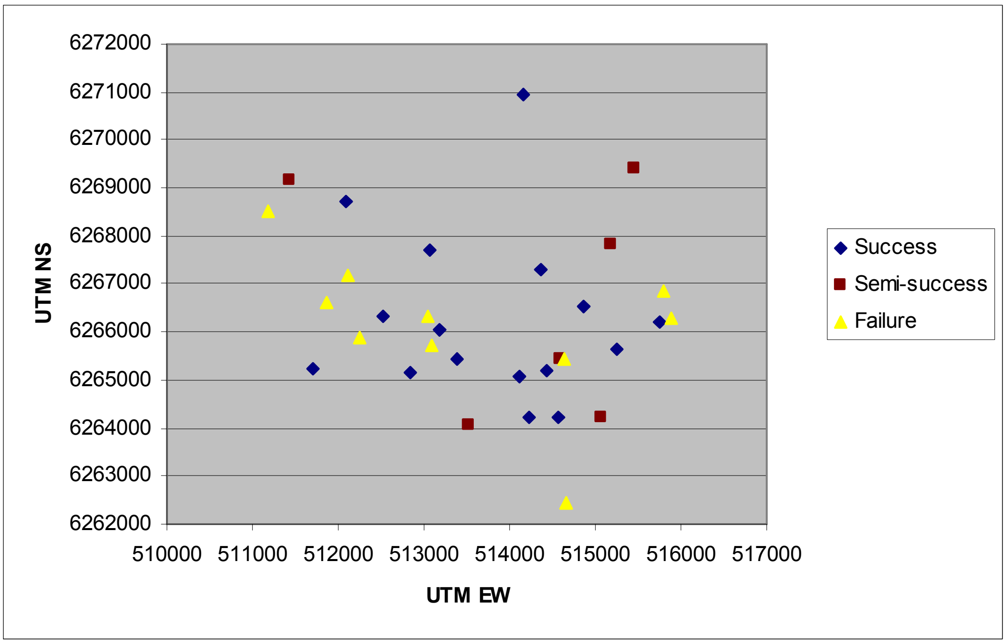

Figure 27: UTM coordinates for the reservoir liner shoes

Next, the wellbore inclination at the liner shoe versus the length of the liner was plotted, see Figure 28. A correlation between the length and the inclination is noticed, indicating that the liner gets longer as the wells become more horizontal.

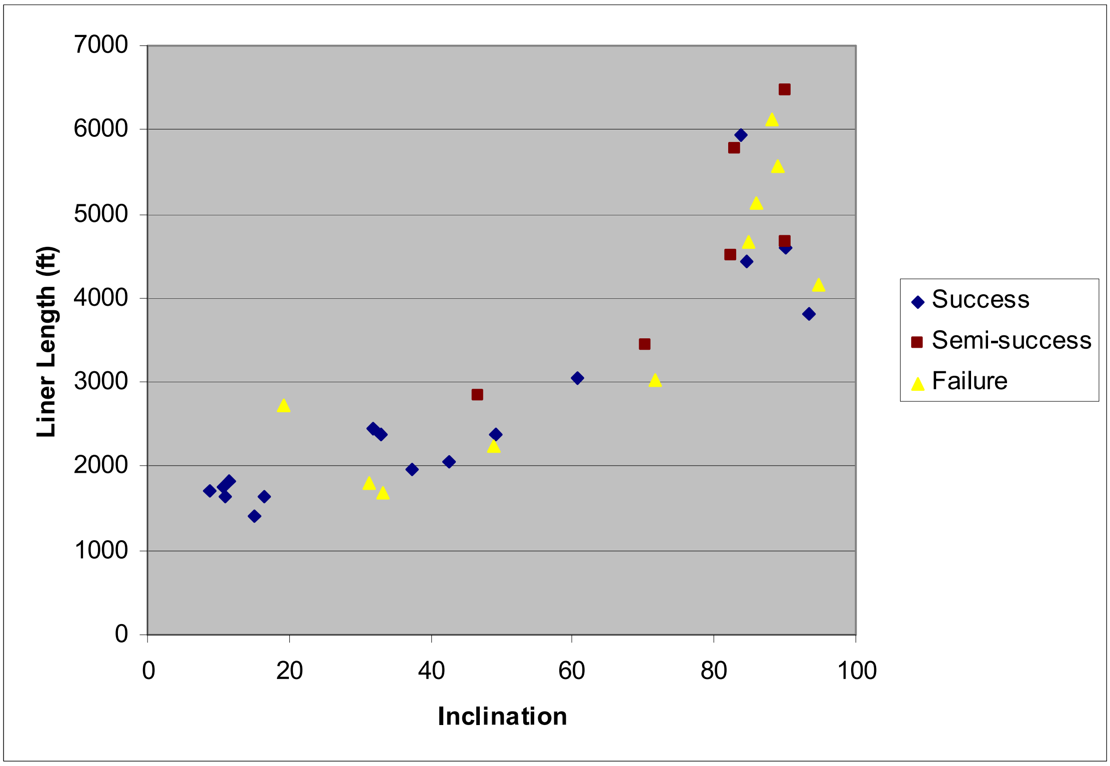

Figure 28: Length of liner versus inclination at shoe

From the figure it is also observed that as the wells become more horizontal, i.e. the inclination at the shoe gets higher, the number of failed or semi-successful wells increases. In fact, based on the data presented in Figure 28, only 4 out of 13 jobs, or 31 %, where the inclination is higher than 80 º are regarded as successes. Examples of the same trend can also be observed in Figure 26.

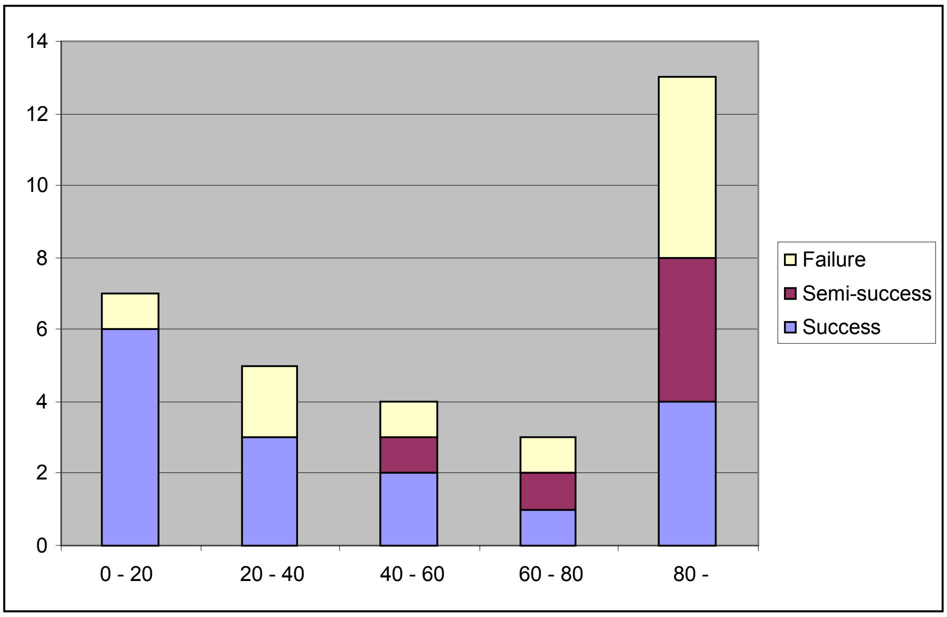

Figure 29: Outcome for the different liner shoe inclination intervals

Figure 29 shows how the outcome varies for the different liner shoe inclination intervals, whereas Figure 30 shows the same as percentage of each interval. 13 out of the 32 wells have an inclination above 80 º, 7 are in the interval between 40 º and 80 º, and thus 12 have an inclination below 40 º. As seen from Figure 29 failures have been experienced all over, but looking at Figure 30 it is observed that the percentage of failures and semi-successes increases with higher inclination. This is the same trend as for the increased liner length seen in Figure 25.

As mentioned, there is a dependency between length of the liner and inclination at the shoe, as shown in Figure 28. This can be explained by the difference between MD and TVD. In a near vertical well, i.e. low angle at the shoe, the MD and TVD are almost equal, thus a relatively short liner is needed to cover the reservoir. For a highly deviated or horizontal well, i.e. high angle at the shoe, the MD is always higher than TVD since building of inclination happens over length. The result is that the liner increases in length as the inclination increases. In addition, wells with highly deviated or horizontal intervals in the reservoir are in general drilled farther to maximize contact area with the reservoir.

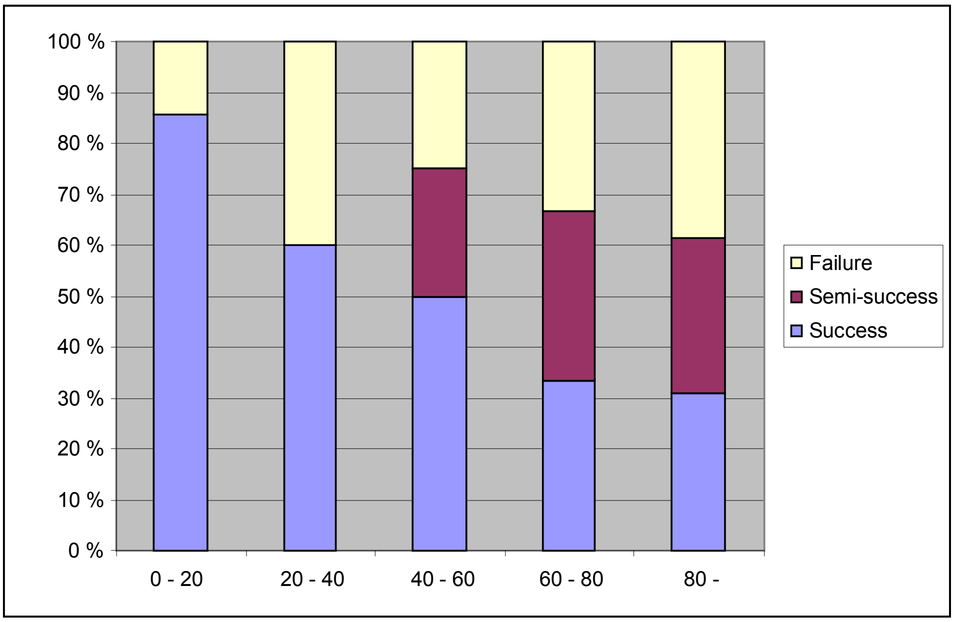

Figure 30: Percentage outcome for the different liner shoe inclination intervals

5 Conclusions

From the conventional versus foam cement discussion it is concluded that foam cement will be the best option for cementing reservoir liners on the Ekofisk M field. There are several factors contributing to this conclusion.

First, the ductility of foam cement is superior when it comes to reservoir compaction. Where conventional cement tends to be brittle, foam cement is better suited to resist mechanical and thermal loading which can occur over the operating and economic life of the producing well. Further, foam cement is less permeable than conventional cement which is important for zonal isolation. Finally, foam cement is more applicable as it is available in a wider, and lower, density range than conventional cement.

Liner manipulation is beneficial for the cement displacement, and thus movement of the string throughout the displacement is desired. Rotation is preferred over reciprocation because then the liner shoe is placed, and kept, at the desired setting depth during the cement operation. Rotation can be maintained as long as the torque limit is not exceeded. The different components in the liner running string have differing torque limits, but normally it is the drill pipe that puts restrictions on the torque.

Based on the evaluation of the 32 foam cemented reservoir liners several observations are made. First of all, the length of the liner has an effect on the outcome. The case studies indicate that the success rate decreases from 78 % for liners shorter than 2000 ft to 25 % for liners between 5000 and 6000 ft. It is also noticed that the 6 5/8’’ liner size is used for all reservoir liners shorter than 3000 ft.

Both UTM coordinates and inclination versus azimuth were plotted for the liner shoes, but no clear correlation was seen between placement of the shoe and outcome of the cement job. However, this came as no big surprise as careful well path planning is carried through to avoid trouble zones in the reservoir.

When plotting the liner length versus wellbore inclination an obvious correlation was observed. As the liners became longer the wellbore inclination increased which, was as anticipated. This plot also showed that only 4 out of 13 liners with an inclination above 80 º were regarded as a success.

As a consequence, the outcome of the foam cement jobs was plotted in intervals of 20 º. This plot clearly indicates that the success rate decreases as the inclination increases.

Looking merely on the 10 failures it is observed that 7 of them are related to not being able to regain rotation after setting the liner hanger. The reason for this has not been investigated in this thesis. However, looking at the design of liner hangers with respect to bypass area could be a good thesis for later students.

6 Nomenclature

API - American Petroleum Institute
BHA - Bottom Hole Assembly
bbl - barrel
bbls - barrels
BOE - Barrels of Oil Equivalent
bph - barrels per Hour
bpm - barrels per Minute
CBL - Cement Bond Log
CF - Correction Factor
DLS - Dog-Leg Severity
ECD - Equivalent Circulating Density
ft - foot / feet
gpm - gallons Per Minute
ID - Inner Diameter
LCM - Lost Circulation Material
MD - Measured Depth
MW - Mud Weight
MWD - Measurement While Drilling
OBM - Oil Based Mud
OD - Outer Diameter
POOH - Pull Out of Hole
PMS - Polymelamine Sulfonate
PNS - Polynapthalene Sulfonate
ppg - pounds per gallon
psi - pounds per square inch
ROP - Rate of Penetration
RPM - Revolutions per Minute
TD - Total Depth
TDS - Top Drive System
TOC - Top of Cement
TOL - Top of Liner
TVD - True Vertical Depth
UTM - Universal Transverse Mercator
WBM - Water Based Mud

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Appendix A Reservoir Cement Jobs on Ekofisk M

The data presented in appendix A are information about the various foam cement jobs on the wells drilled from Ekofisk M.

A-1 Inclination, azimuth, TVD, and UTM-coordinates at liner shoe

Wellbore	MD	Inclination	Azimuth	TVD RKB	UTM NS	UTM EW
2/4-M-1 A	15984	84,880	299,850	10306,11	6268526,131	511173,288
2/4-M-5	13945	33,270	82,270	10837,89	6267186,843	512112,955
2/4-M-8 A T4	21538	88,060	188,590	10612,13	6262458,781	514669,527
2/4-M-10 A	15351	89,004	113,653	10516,69	6266860,215	515799,087
2/4-M-11	15767	94,788	151,443	10746,63	6265895,469	512260,048
2/4-M-25 A	14996	85,949	102,965	10615,27	6266310,079	515891,452
2/4-M-27	11641	48,910	214,620	10736,61	6266338,989	513039,916
2/4-M-13 A	13592	31,360	203,820	10769,19	6265743,527	513089,610
2/4-M-2	13777	19,185	207,523	11041,51	6266630,254	511856,068
2/4-M-29 A	17129	71,830	344,020	10940,34	6265451,250	514626,262
2/4-M-4	13200	46,630	93,620	11065,07	6267811,331	515190,801
2/4-M-7	16875	82,970	304,110	10473,21	6269181,507	511442,489
2/4-M-9	15997	82,470	76,240	10419,75	6269399,402	515459,154
2/4-M-26	16245	90,044	127,008	10516,61	6264065,698	513531,747
2/4-M-28	16939	90,170	179,930	10471,47	6264212,614	515062,510
2/4-M-29 T2	16678	70,320	350,440	10979,45	6265427,318	514599,042
2/4-M-3	12205	33,100	226,630	10854,17	6266327,382	512526,168
2/4-M-6 T2	14022	14,999	250,999	10614,34	6268715,676	512086,465
2/4-M-8	12669	42,47	28,93	11051,46	6266542,243	514853,292
2/4-M-12 T2	15355	49,100	121,960	10868,69	6264216,676	514227,699
2/4-M-13	11839	16,450	135,170	10716,82	6267688,943	513058,273
2/4-M-14 T2	14432	90,003	102,079	10663,95	6265635,835	515244,464
2/4-M-15 A	18922	83,820	13,420	10638,01	6270927,493	514150,977
2/4-M-16	15003	93,480	229,110	10622,12	6265227,912	511700,788
2/4-M-17	13473	37,410	163,040	11094,22	6265163,026	512830,946
2/4-M-18	12547	8,910	199,423	11048,71	6265457,870	513385,279
2/4-M-19 T2	13735	60,620	136,260	10788,54	6267304,309	514370,624
2/4-M-20	14570	84,540	116,140	10751,87	6266202,522	515741,372
2/4-M-22	11697	10,770	208,920	10954,06	6266037,739	513176,077
2/4-M-23	13300	11,620	177,780	11183,4	6265075,139	514106,751
2/4-M-24	13248	11,100	98,180	11089,52	6265207,755	514436,108
2/4-M-30	16123	31,980	74,700	11003,89	6264223,970	514561,879

A-2 Inclination, azimuth, TVD, and UTM-coordinates at top of liner

Wellbore	MD	Inclination	Azimuth	TVD RKB	UTM NS	UTM EW
2/4-M-1 A	11318	41,905	286,125	9247,52	6267879,816	512358,396
2/4-M-5	12263	16,669	168,136	9336,81	6267290,080	511928,946
2/4-M-8 A T4	15411	72,413	176,988	9730,92	6264273,841	514787,121
2/4-M-10 A	9785	45,165	91,334	9240,74	6267343,716	514268,563
2/4-M-11	11599	46,944	191,884	9428,69	6267020,194	512001,732
2/4-M-25 A	9872	37,960	111,884	9391,72	6266906,999	514547,816
2/4-M-27	9395	36,377	220,769	9200,56	6266734,761	513342,554
2/4-M-13 A	11795	51,216	195,586	9291,61	6266036,954	513168,929
2/4-M-2	11043	47,995	224,351	9342,6	6267151,370	512197,204
2/4-M-29 A	14094	52,808	45,153	9649,23	6264690,004	514510,696
2/4-M-4	10350	40,879	81,486	9318,64	6267882,654	514516,643
2/4-M-7	11095	59,481	324,014	9335,93	6267801,647	512424,286
2/4-M-9	11492	46,630	27,910	9354,53	6268578,556	514501,965
2/4-M-26	11575	48,137	191,199	9445,71	6265274,461	513104,762
2/4-M-28	10476	40,049	149,897	9430,24	6265916,476	514409,061
2/4-M-29 T2	13230	12,923	303,243	8918,31	6264755,208	514948,641
2/4-M-3	9821	34,552	233,778	9290,78	6266708,748	512906,362
2/4-M-6 T2	12614	26,962	308,305	9274,93	6268692,921	512204,519
2/4-M-8	10612	26,073	63,179	9434,43	6266221,108	514647,508
2/4-M-12 T2	12974	54,063	164,368	9618,87	6264643,762	513807,482
2/4-M-13	10193	6,220	160,779	9119,22	6267774,009	512978,259
2/4-M-14 T2	9835	38,545	158,589	9311,73	6266474,680	514408,545
2/4-M-15 A	12994	62,125	4,340	9448,36	6269334,022	513955,402
2/4-M-16	11200	41,226	232,073	9518,19	6266041,188	512386,470
2/4-M-17	11499	35,281	178,572	9506,64	6265507,629	512738,378
2/4-M-18	10830	13,861	192,053	9350,15	6265530,337	513402,831
2/4-M-19 T2	10687	38,977	132,083	9191,79	6267904,103	513865,163
2/4-M-20	10139	36,979	111,463	9399,91	6266640,345	514596,672
2/4-M-22	9942	18,721	212,962	9238,71	6266133,493	513231,660
2/4-M-23	11473	20,262	173,600	9406,47	6265199,110	514124,568
2/4-M-24	11601	16,890	136,799	9481,52	6265242,568	514340,718
2/4-M-30	13670	53,215	134,043	9657,13	6264302,534	513982,787

A-3 Liner size and length, rotational information and comments

Wellbore	OD	Length	Rotation	Comments
2/4-M-1 A	6-5/8	4666	No	Initially rotated with 10 RPM / 22-25 kft-lbs. String weight suddenly dropped, indication of RT free from liner. Attempted to rotate to confirm free, string stalled out at 30 kft-lbs, still attached. Dropped ball and set hanger. Not able to rotate liner.
2/4-M-5	6-5/8	1682	No	Rotate liner at bottom with 20 RPM / 18-20.5 kft-lbs. Not able to rotate after setting the hanger. Max applied torque 25 kft-lbs.
2/4-M-8 A T4	5	6127	No	Initially rotated with 10 RPM / 19 kft-lbs after tagging TD. Stopped rotating when pumping ball, not able to rotate after hanger was set (30 kft-lbs).
2/4-M-10 A	6-5/8	5566	No	Liner rotated with 30 RPM / 26-30 kft-lbs at bottom. String stuck when positioning, not able to rotate nor reciprocate.
2/4-M-11	6-5/8	4168	No	Liner rotate prior to setting the hanger with 35 RPM / 22 kft-lbs. Experienced difficulties with setting the hanger, not able to rotate liner after hanger was set.
2/4-M-25 A	5-1/2 x 6-5/8	5124	No	Liner rotated with 25 RPM / 16-27 kft-lbs prior to setting the hanger. Not able to rotate the liner after the hanger was set, max trq applied 31 kft-lbs..
2/4-M-27	6-5/8	2246	No	Rotate liner prior to setting hanger, 10 RPM / 10-14 kft-lbs. No info on rotation after hanger was set. Perform cement squeeze job at the 6-5/8" shoe.
2/4-M-13 A	6-5/8	1797	No	Rotate liner with 10 RPM / 18-20 kft-lbs prior to setting the hanger. Establish rotation after hanger was set at 10 RPM / 14-15 kft-lbs. Hole packing off when pumping spacer A. Reached trq limit at 33 kft-lbs, unable to rotate rest of the job.
2/4-M-2	6-5/8	2734	No	Rotate liner with 30 RPM / 30 kft-lbs at setting depth. Stopped rotation due to cmt head started turning. Reciprocated during cmt job with full returns.
2/4-M-29 A	6-5/8	3035	No	Rotate liner prior to setting hanger, 20 RPM / 24 kft-lbs while circulating. Attempted to start rotation with max 34 kft-lbs torque after hanger is set, no success.
2/4-M-4	6-5/8	2850	Stalled	Establish rotation at setting depth, 20 RPM / 18-21 kft-lbs. Rotate liner at 20 RPM during cmt job. Stopped rotation 15 bbls prior to bump plug due to torque limit at 24.5 kft-lbs.

2/4-M-7	6-5/8	5780	Stalled	Rotate liner with 16-20 kft-lbs after setting the hanger. Liner rotation stopped 70 bbls before completed due to exceeding 30 kft-lbs.
2/4-M-9	6-5/8	4505	Stalled	Rotate liner with 10 RPM / 18-21 kft-lbs prior to setting hanger. Establish rotation with 10 RPM / 17-20 kft-lbs prior to pumping cmt. String stalled out after 110 of 157 bbls slurry into open hole.
2/4-M-26	6-5/8	4670	Stalled	Rotated liner prior to setting the hanger with 10 RPM / 17-19 kft-lbs. Partly lost return, and stopped rotation. Set hanger. Intermittently rotate string when pumping cmt. String stalled out after 1600 strokes pumped, 35.5 kft-lbs. Cmt entered open hole after 1200 strokes displaced.
2/4-M-28	6-5/8	6463	Stalled	Rotate with 20 RPM / 22 kft-lbs prior to setting hanger. String stalled out at 32 kft-lbs after 55 bbls cmt slurry entered open hole.
2/4-M-29 T2	6-5/8	3448	Stalled	Rotate string with 20 RPM / 20 kft-lbs prior to setting hanger. Rotate 20 RPM during cmt and displacement. String stalled out 50 strokes prior to bump plug.
2/4-M-3	6-5/8	2384	Yes	Rotate with 20 RPM / 14-18 kft-lbs, full returns.
2/4-M-6 T2	6-5/8	1408	Yes	Rotate liner with 20 RPM / 16-19 kft-lbs prior to setting the hanger. Rotate with 20 RPM / 10.4-17 kft-lbs throughout job.
2/4-M-8	6-5/8	2057	Yes	Rotate string at 10 RPM / 14-16 kft-lbs prior to pumping cmt. Rotate string with 25 RPM / 19.5 kft-lbs max trq. Some difficulties setting / releasing from hanger.
2/4-M-12 T2	6-5/8	2381	Yes	20 RPM / 17 kft-lbs rotation after hanger was set. Rotate through job with 20 RPM / 17-22 kft-lbs.
2/4-M-13	6-5/8	1646	Yes	Rotate string with 30 RPM / 12-14 kft-lbs after tagging TD. Rotate liner with 20 RPM / 16 kft-lbs max during job. Set / expand hanger.
2/4-M-14 T2	5	4597	Yes	Rotate liner with 25 RPM / 11-15 kft-lbs initially. Set hanger and establish rotation with 15 RPM / 8-12 kft-lbs. Rotate liner during cmt job with 25 RPM / max trq 17 kft-lbs.
2/4-M-15 A	5-1/2 x 6-5/8	5928	Yes	Liner rotated with 10 RPM / 22-25 kft-lbs while pumping ball. Liner string rotated with 20 RPM / 28 kft-lbs during cmt job.
2/4-M-16	6-5/8	3803	Yes	Establish rotation after setting hanger, rotated through the job eith 22-24 kft-lbs.
2/4-M-17	6-5/8	1974	Yes	Establish rotation after hanger is set, 20

				RPM / 12 kft-lbs. Rotate liner throughout job.
2/4-M-18	6-5/8	1717	Yes	After hanger was set, rotate liner with 10 RPM / 8-9 kft-lbs. Rotate liner with 10 RPM during cmt. Trq going from 8 to 11 kft-lbs when cmt entering open hole.
2/4-M-19 T2	5	3048	Yes	Establish rotation after hanger is set, 20 RPM / 11-12 kft-lbs. Rotated throughout job.
2/4-M-20	5	4431	Yes	Rotate liner at 7-10 kft-lbs after setting hanger. Rotated at 20 RPM during the job.
2/4-M-22	6-5/8	1755	Yes	Rotate liner with 10 RPM during cmt job.
2/4-M-23	6-5/8	1827	Yes	Troubleshooting to release running tool, rotate liner with 10 RPM / 14 kft-lbs when liner suddenly dropped to bottom. Keep same rotation while cmt is pumped out of liner.
2/4-M-24	6-5/8	1647	Yes	Establish rotation with 15 RPM / 12 kft-lbs after setting hanger, and rotated throughout the job.
2/4-M-30	6-5/8	2453	Yes	Rotate liner with 15 RPM / 18-22 kft-lbs prior to pumping spacer and cmt. Kept same rotation throughout job, and set hanger.

Appendix B Case 1: M-1 A

The data given in appendix B are information regarding M-1 A.

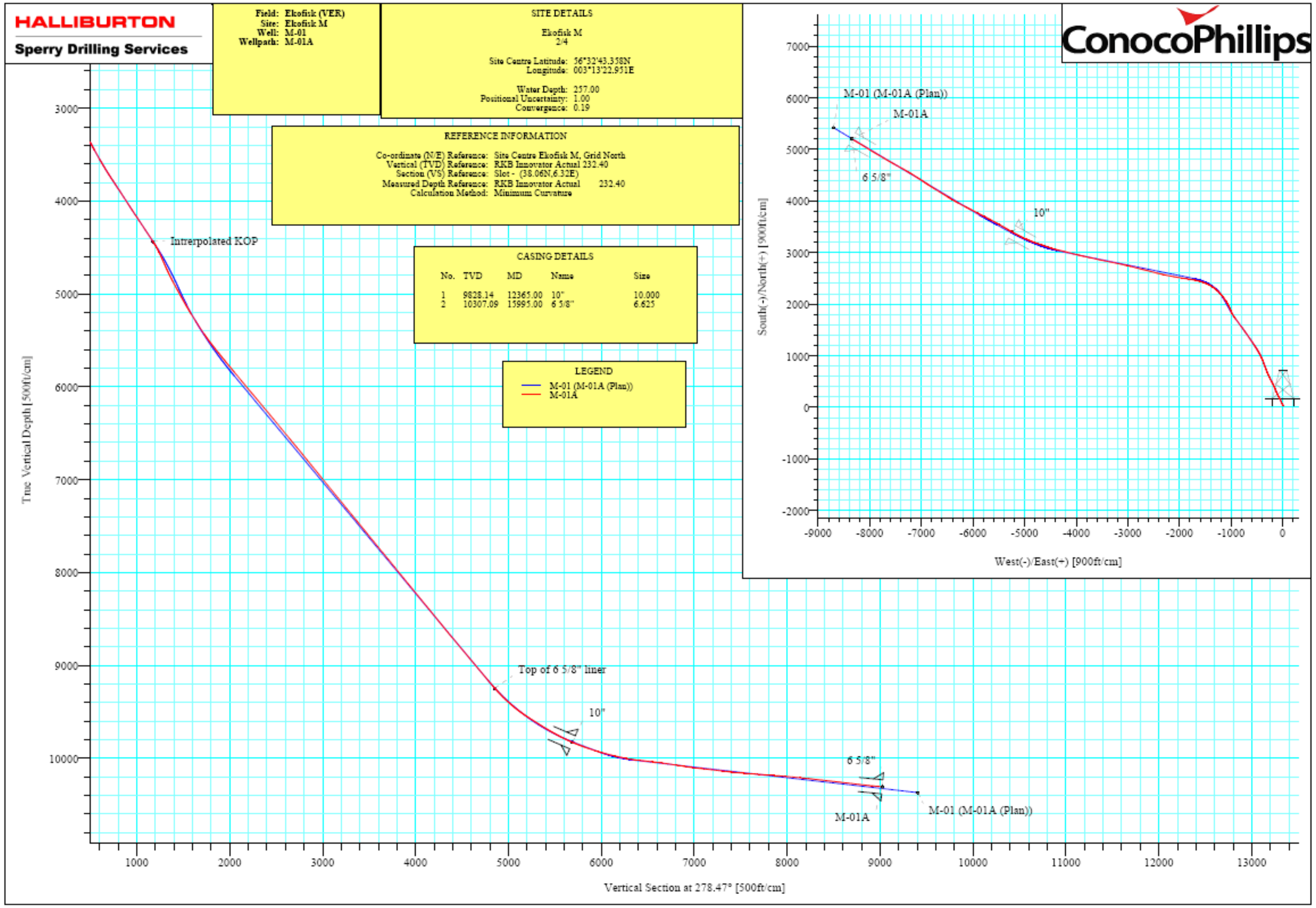
B-1 Directional Data

The directional data will be given as a plot. However, to show the data behind the plot the directional data are included for M-1 A.

MEAS.DEPTH	INCLIN.	AZIMUTH
0.000	0.000	0.000
480.000	0.000	0.000
596.320	0.440	88.100
725.900	0.620	122.460
861.000	0.700	152.800
993.000	0.880	155.600
1125.700	1.230	293.030
1261.400	1.850	318.760
1391.900	3.520	326.510
1467.400	5.110	324.750
1545.400	5.990	333.460
1675.900	9.010	334.520
1809.700	11.530	333.640
1943.200	13.700	337.870
2019.020	15.610	337.630
2151.200	18.480	333.330
2284.900	21.060	330.570
2417.200	23.580	334.140
2550.700	26.270	337.000
2682.400	28.500	337.890
2815.300	29.540	334.280
2947.500	32.090	333.100
3018.300	33.030	332.550
3079.300	33.820	332.540
3211.400	37.370	335.040
3343.600	41.600	337.990
3476.000	45.290	339.490
3609.300	47.280	340.100
3743.600	44.530	335.330
3875.000	44.520	331.630
4007.800	43.320	328.770
4179.900	44.510	325.840
4272.400	44.060	325.210
4404.900	43.520	325.420
4536.900	43.370	325.220
4669.200	43.670	324.370
4803.500	43.380	323.480
4935.500	43.110	323.430
5067.600	43.160	323.600
5103.000	43.170	324.020
5168.000	41.000	327.480
5268.000	40.440	333.850
5368.000	40.160	337.530
5468.000	39.180	335.220
5568.000	38.750	330.430
5668.000	38.650	326.980
5768.000	38.460	324.780
5971.700	36.540	318.390
6104.100	36.260	312.540
6236.800	36.300	306.040
6368.900	36.360	300.270
6501.500	38.650	294.470
6634.100	39.580	289.890
6765.800	39.750	285.060
6899.700	39.650	281.640
7032.600	39.680	279.060
7165.100	40.110	277.800
7297.500	39.710	279.220
7431.200	40.020	279.760
7563.700	39.580	280.580
7696.100	39.530	281.330
7828.200	39.530	281.870
7960.500	39.800	283.400
8092.800	39.170	284.150
8225.800	39.360	284.860
8358.000	39.220	284.190
8490.700	39.250	283.210
8623.100	39.320	284.150
8755.600	39.480	284.700
8887.900	39.250	284.960
9020.500	39.540	282.880
9155.300	39.110	281.780
9287.700	39.370	281.280
9420.000	39.530	281.680
9552.200	39.170	281.570
9685.500	39.320	281.560
9817.700	39.220	281.940

9950.100	39.460	282.480
10082.200	39.340	282.670
10214.700	39.200	282.000
10347.000	39.050	282.470
10479.600	39.350	283.600
10611.800	40.100	284.050
10744.200	40.140	284.550
10878.300	40.220	284.280
11010.500	40.100	283.350
11142.500	39.730	283.060
11274.700	40.740	284.460
11407.000	44.370	289.320
11533.700	48.400	289.890
11665.100	52.870	287.810
11796.100	57.670	288.830
11934.100	58.450	292.110
12070.700	60.510	294.970
12203.200	63.800	297.560
12508.800	71.730	300.640
12581.900	72.910	300.110
12642.100	73.020	299.710
12714.400	75.280	298.900
12774.700	76.290	298.660
12842.700	76.410	298.120
12906.800	78.800	297.920
12975.400	78.360	297.250

13039.500	81.580	297.560
13106.400	82.330	297.030
13171.400	84.020	297.940
13305.500	84.380	296.720
13435.400	81.960	297.650
13570.300	82.070	298.040
13702.100	81.210	300.410
13834.800	84.580	302.440
13968.000	84.200	300.970
14100.400	83.560	301.380
14233.500	83.950	303.160
14365.300	86.310	304.280
14498.500	85.740	302.200
14559.300	86.310	302.000
14631.200	86.540	302.350
14763.400	85.860	299.580
14895.700	84.890	298.750
15028.600	85.130	299.080
15161.100	83.760	299.890
15294.100	84.200	300.870
15426.400	83.700	300.180
15558.400	84.080	301.350
15691.300	83.580	301.720
15823.900	84.570	301.060
15956.800	84.880	299.850
15996.000	84.880	299.850


HALLIBURTON
Sperry Drilling Services
Field: Ekofisk (VER)
Site: Ekofisk M
Well: M-01
Wellpath: M-01A
SITE DETAILS
Ekofisk M
2/4
Site Centre Latitude: 56°32'43.358N
Longitude: 003°13'22.951E
Water Depth: 257.00
Positional Uncertainty: 1.00
Convergence: 0.19
REFERENCE INFORMATION
Co-ordinate (N/E) Reference: Site Centre Ekofisk M, Grid North
Vertical (TVD) Reference: RKB Innovator Actual 232.40
Section (VS) Reference: Slot - (38.06N,6.32E)
Measured Depth Reference: RKB Innovator Actual 232.40
Calculation Method: Minimum Curvature
CASING DETAILS
No. TVD MD Name Size
1 9828.14 12365.00 10" 10.000
2 10307.09 15995.00 6 5/8" 6.625
LEGEND
M-01 (M-01A (Plan))
M-01A
Intrerpolated KOP
Top of 6 5/8" liner
10"
6 5/8"
M-01A
M-01 (M-01A (Plan))
True Vertical Depth [500ft/cm]
Vertical Section at 278.47° [500ft/cm]
ConocoPhillips
M-01 (M-01A (Plan))
M-01A
6 5/8"
10"
South(-)/North(+) [900ft/cm]
West(-)/East(+) [900ft/cm]

B-2 Bit Report

HALLIBURTON
Sperry Drilling Services

2/4-M-1 A Daily Drilling Report

ConocoPhillips

Bit # 9RR: 8 1/2" Hughes MXL28CDXOD, TFA: 0.746 in2, Jets: 3 x 18,
Serial no: 6065492

Grading : 2-3-WT-A-E-I-CT-TD

Last Casing :
10" Liner set at 12364 ft MD

INFLOW TEST

Activity and Tool information	
Start RIH:	10 June 08, 17:00
Start drilling:	11 June 08, 17:20
Drilling completed at:	13 June 08, 11:30
OOH at:	14 June 08, 19:25
Motor Assembly:	No
Revs Per Gallon:	Na
Bend Angle:	Na

Remarks:
Drilled 8 1/2" section to TD at 15996 ft MD / 10307.4 ft TVD.

SECTION AVERAGES

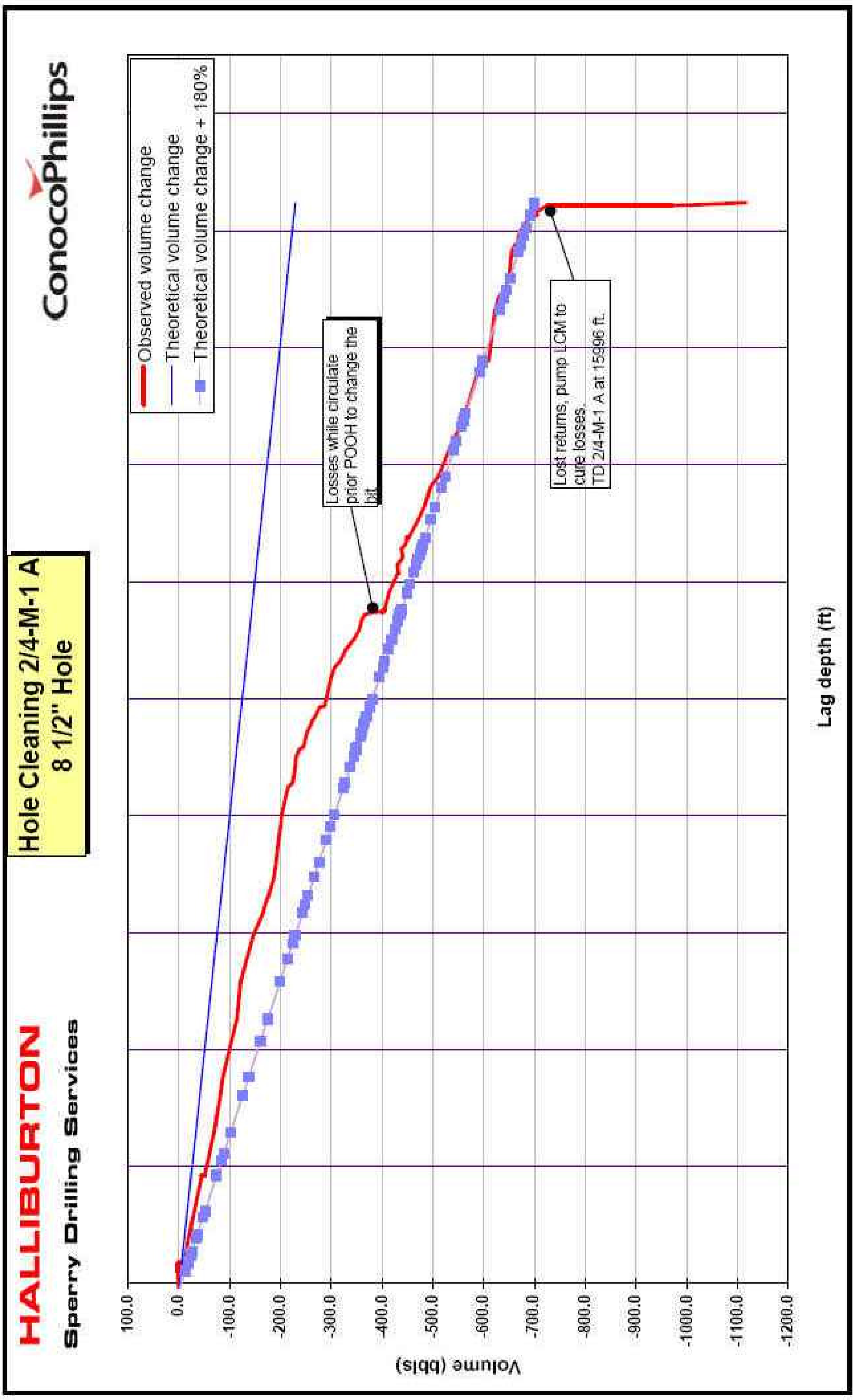
	Min:	Max:	Avg:
RPM string	87	140	138
RPM total	87	140	138
WOB	1.0	27.9	19.1
Flow	498	603	600
SPP	1366	3077	2858
TRQ	13049	16643	14449

To be filled in when finished drilling

In at:	14731		10-Jun-08	11-Jun-08	12-Jun-08	13-Jun-08	14-Jun-08
Out at:	15996	Cumulative:	Daily	Daily	Daily	Daily	Daily
			14731	14977	15987	15996	15996
Rotating Drilling Hrs on Btm		17.1	0.0	3.9	13.1	0.1	0.0
Sliding Drilling Hrs on Btm		0.0	0.0	0.0	0.0	0.0	0.0
Tot. HOB on form.		17.1	0.0	3.9	13.1	0.1	0.0
RIH		15.2	1.0	14.2	0.0	0.0	0.0
POOH		18.9	0.0	1.5	0.0	8.3	9.1
OOH/m.u. BHA		1.6	0.0	1.6	0.0	0.0	0.0
Others (drill cmt, cond mud, cnx., etc.)		45.7	6.0	2.8	10.9	15.6	10.4
Total Daily Hours		98.5	7.0	24.0	24.0	24.0	19.5
Connections number of		11.0	0.0	3.0	7.0	1.0	0.0
Total Connection Time mins		121.0	0.0	30.0	81.0	10.0	0.0
Average Connection Time		11.0	0.0	10.0	11.6	10.0	0.0
Total Circulation Hrs		50.9	0.0	8.4	22.8	15.1	4.6
Total Bit Revs, Krevs (on&off)		207.3	0.0	39.4	143.9	21.5	2.5
Motor Revs On Btm, Krev		0.0	0.0	0.0	0.0	0.0	0.0
Motor Revs Off Btm, Krev		0.0	0.0	0.0	0.0	0.0	0.0
String Revs on Btm, Krevs		140.5	0.0	29.4	109.9	1.2	0.0
String Revs off Btm,Krevs		66.8	0.0	10.0	34.0	20.3	2.5
Off btm string rot hrs		36.4	0.0	3.2	7.3	20.8	5.1
Bit Wear Index, Klb Revs / 1000		2603.8	0.0	558.9	2027.3	17.6	0.0
Total Feet Drilled		1265.0	0.0	246.0	1010.0	9.0	0.0
Rotating Feet Drilled		1265.0	0.0	246.0	1010.0	9.0	0.0
Sliding Feet Drilled		0.0	0.0	0.0	0.0	0.0	0.0
Rotating avg ROP, ft/hr		74.0	0.0	63.1	77.1	90.0	0.0
Sliding ROP, ft/hr		0.0	0.0	0.0	0.0	0.0	0.0
Total ROP, ft/hr		74.0	0.0	63.1	77.1	90.0	0.0

Note: Connection time is time taken from pumps off until tagging bottom on new stand
Stand length is 132.7 ft. (3 long joints per stand)

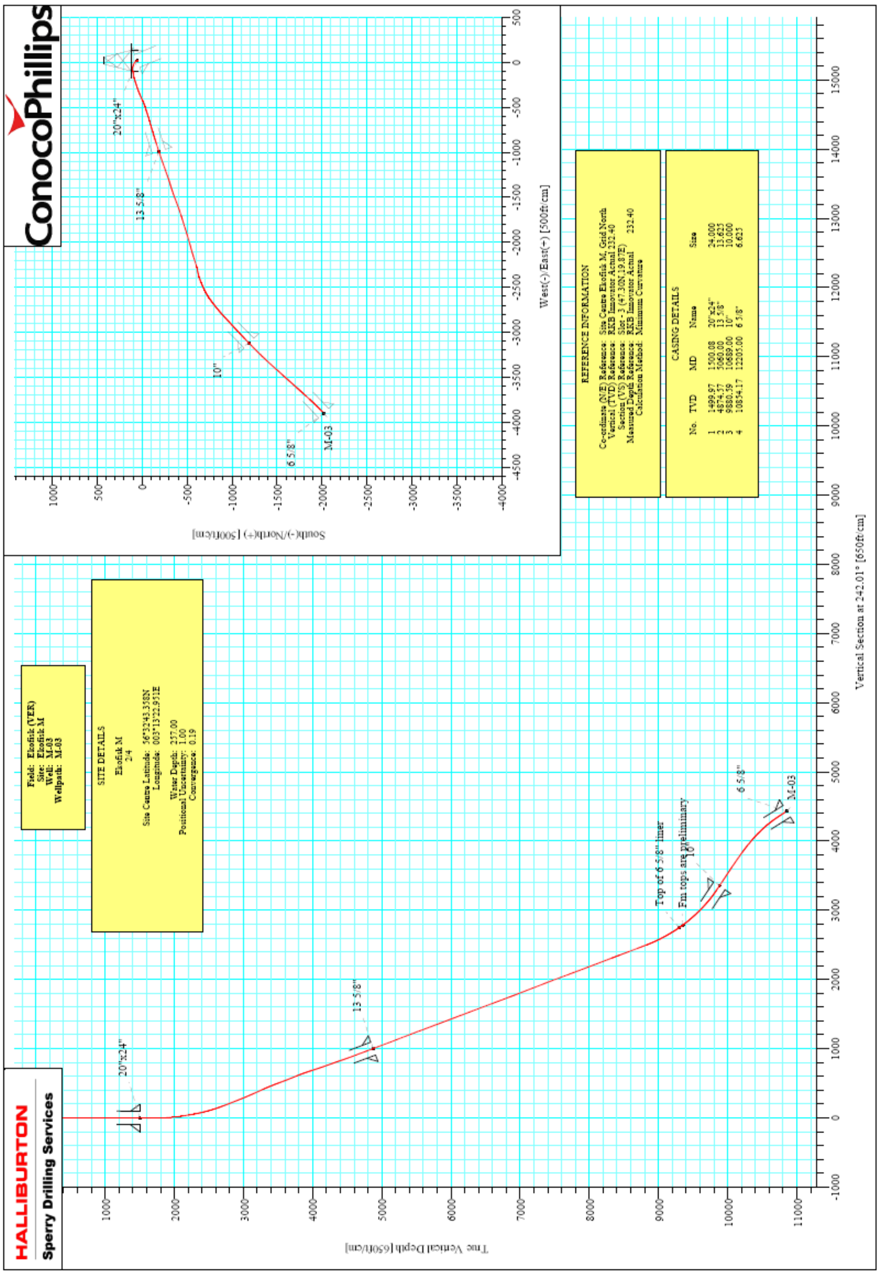
B-3 Hole Cleaning



Appendix C Case 2: M-3

The data given in appendix C are information regarding M-3. Note that there is no information on hole cleaning for this well.

C-1 Directional Data



C-2 Bit Report

HALLIBURTON
Sperry Drilling Services

2/4 M-03 Daily Drilling Report

ConocoPhillips

Bit # 4RR: 8 1/2" HTC MXL-28CHDX TFA: 0.746 in2, Jets: 3 x 18
Serial no: 6053979

Grading : 1-2-WT-A-E-I-CT-TD

Last Casing :
10" Liner Set at :
10689 ft

Inflow test :

Activity and Tool information		Remarks:
Start RIH:	07 Feb 08, 00:50	Drill 8 1/2" section to TD.
Start drilling:	07 Feb 08, 10:50	
Drilling completed at:	10 Feb 08, 00:10	
OOH at:	10 Feb 08, 23:00	
Motor Assembly:	No	
Revs Per Gallon:	NA	
Bend Angle:	NA	

SECTION AVERAGES	Min:	Max:	Avg:
RPM string	75	160	152
RPM total	75	160	152
WOB	0.4	34.5	20.9
Flow	558.0	584.0	573.9
SPP	2549	3509	3285
TRQ	7401	9876	8987

To be filled in when finished drilling

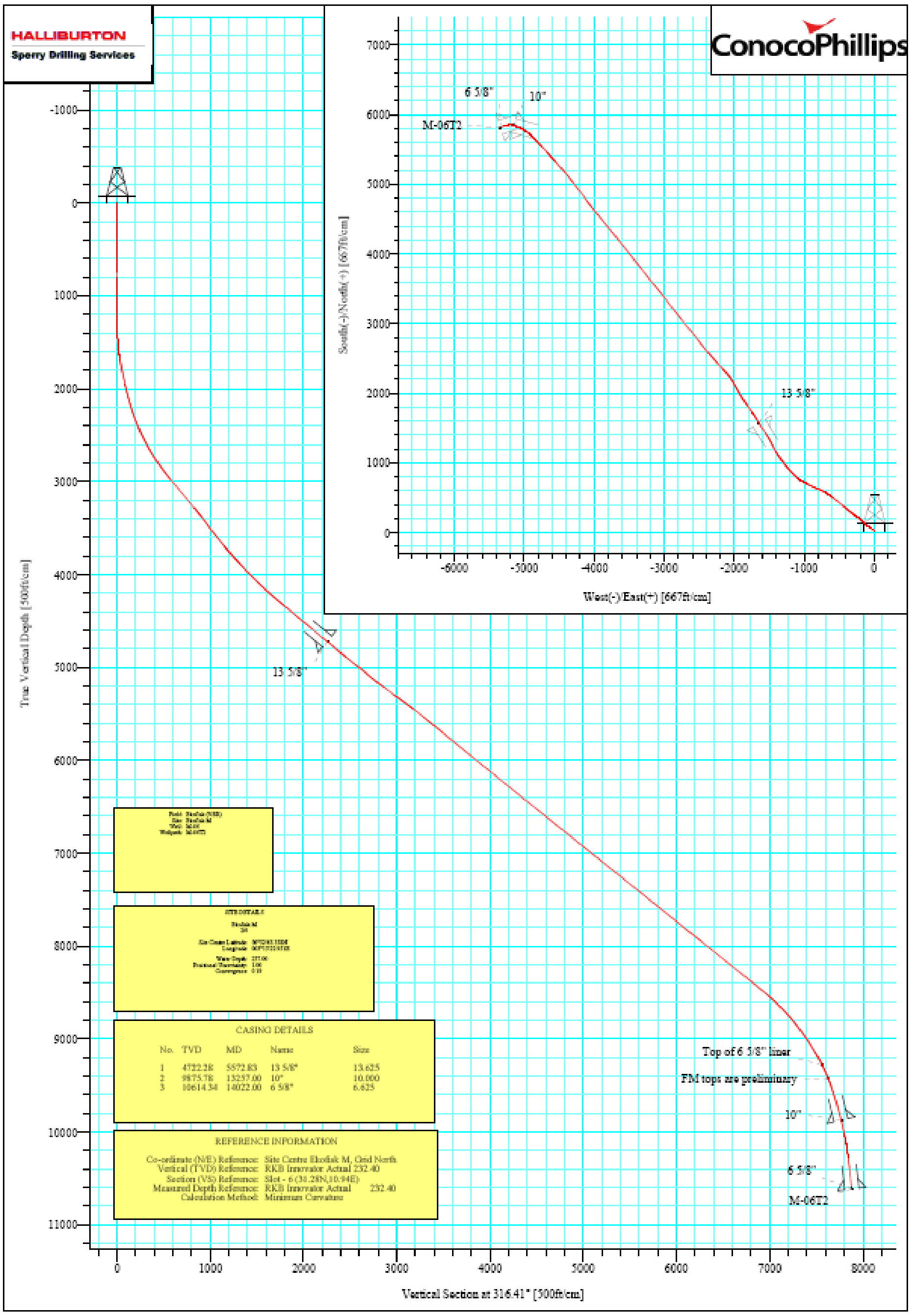
In at:	10698		07-Feb-08	08-Feb-08	09-Feb-08	10-Feb-08
Out at:	12210	Cumulative:	Daily	Daily	Daily	Daily
Midnight Depth MD			10931	11556	12207	12210
Rotating Drilling Hrs on Btm		29.6	3.7	6.2	19.4	0.3
Sliding Drilling Hrs on Btm		0.0	0.0	0.0	0.0	0.0
Tot. HOB on form.		29.6	3.7	6.2	19.4	0.3
RIH		10.0	10.0	0.0	0.0	0.0
POOH		22.7	0.0	0.0	0.0	22.7
OOH/m.u. BHA		0.0	0.0	0.0	0.0	0.0
Others (drill cmt, cond mud, cnx., etc.)		31.9	9.5	17.8	4.6	0.0
Total Daily Hours		94.2	23.2	24.0	24.0	23.0
Connections number of		11	1	5	5	0.0
Total Connection Time mins		176	21	82	73	0
Average Connection Time		16.0	21.0	16.4	14.6	0.0
Total Circulation Hrs		67.1	13.4	21.3	23.3	9.1
Total Bit Revs, Krevs (on&off)		345.8	54.3	98.6	179.1	13.8
Motor Revs On Btm, Krev		0.0	0.0	0.0	0.0	0.0
Motor Revs Off Btm, Krev		0.0	0.0	0.0	0.0	0.0
String Revs on Btm, Krevs		250.1	26.9	59.9	161.0	2.3
String Revs off Btm,Krevs		95.7	27.4	38.7	18.1	11.5
Off btm string rot hrs		21.2	3.7	10.5	3.4	3.6
Bit Wear Index, Klb Revs / 1000		5678.9	654.7	1027.8	3953.0	43.4
Total Feet Drilled		1512.0	233.0	625.0	651.0	3.0
Rotating Feet Drilled		1512.0	233.0	625.0	651.0	3.0
Sliding Feet Drilled		0.0	0.0	0.0	0.0	0
Rotating avg ROP, ft/hr		51.1	63.0	100.8	33.6	10.0
Sliding ROP, ft/hr		0	0.0	0.0	0.0	0
Total ROP, ft/hr		51.1	63.0	100.8	33.6	10.0

Note: Connection time is time taken from pumps off until tagging bottom on new stand
Stand length is 132.7 ft. (3 long joints per stand)

Appendix D Case 3: M-6 T2

The data given in appendix D are information regarding M-6 T2. Note that there is no information on hole cleaning for this well.

D-1 Directional Data



D-2 Bit Report

HALLIBURTON
Sperry Drilling Services

2/4 M-06 T2 Daily Drilling Report

ConocoPhillips

Bit # 4RR: 8 1/2" HTC MXL-28CHDX TFA: 0.746 in2, Jets: 3 x 18
Serial no: 5091075

Grading : 1-2-WT-A-E-I-LN-BHA

Last Casing :
10"Liner Set at :
13257ft

Inflow test

Activity and Tool information		Remarks:
Start RIH:	10 Mar 08, 11:15	Tag cmt/float at 1318ft.
Start drilling:	11 Mar 08, 07:55	Drilled 23 ft cement in 2.5 hrs
Drilling completed at:	11 Mar 08, 15:30	Clean out assembly without a MWD or a directional tool.
OOH at:	12 Mar 08, 01:00	Rerun bit used on 2/4 B 18 D
Motor Assembly:	No	
Revs Per Gallon:	NA	
Bend Angle:	NA	

SECTION AVERAGES	Min:	Max:	Avg:
RPM string	60	130	110
RPM total	60	130	110
WOB	0.7	20.3	13.2
Flow	571.4	572.9	571.7
SPP	1526	1590	1552
TRQ	9674	14346	13204

To be filled in when finished drilling

In at:	13280		10-Mar-08	11-Mar-08	12-Mar-08
Out at:	13369	Cumulative:	Daily	Daily	Daily
Midnight Depth MD			13280	13369	13369
Rotating Drilling Hrs on Btm		4.4	0.0	4.4	0.0
Sliding Drilling Hrs on Btm		0.0	0.0	0.0	0.0
Tot. HOB on form.		4.4	0.0	4.4	0.0
RIH		9.7	9.7	0.0	0.0
POOH		7.0	0.0	6.0	1.0
OOH/m.u. BHA		0.0	0.0	0.0	0.0
Others (drill cmt, cond mud, cnx., etc.)		16.6	3.0	13.6	0.0
Total Daily Hours		37.7	12.7	24.0	1.0
Connections number of		0	0.0	0.0	0.0
Total Connection Time mins		0.0	0.0	0.0	0.0
Average Connection Time		0.0	0.0	0.0	0.0
Total Circulation Hrs		12.1	4.4	7.7	0.0
Total Bit Revs, Krevs (on&off)		39.2	0.0	39.2	0.0
Motor Revs On Btm, Krev		0.0	0.0	0.0	0.0
Motor Revs Off Btm, Krev		0.0	0.0	0.0	0.0
String Revs on Btm, Krevs		27.4	0.0	27.4	0.0
String Revs off Btm,Krevs		11.8	0.0	11.8	0.0
Off btm string rot hrs		2.6	0.0	2.6	0.0
Bit Wear Index, Klb Revs / 1000		396.4	0.0	396.4	0.0
Total Feet Drilled		89.0	0.0	89.0	0.0
Rotating Feet Drilled		89.0	0.0	89.0	0.0
Sliding Feet Drilled		0.0	0.0	0.0	0.0
Rotating avg ROP, ft/hr		20.2	0.0	20.2	0.0
Sliding ROP, ft/hr		0.0	0.0	0.0	0.0
Total ROP, ft/hr		20.2	0.0	20.2	0.0

Note: Connection time is time taken from pumps off until tagging bottom on new stand
Stand length is 132.7 ft. (3 long joints per stand)

HALLIBURTON
Sperry Drilling Services

2/4 M-06 T2 Daily Drilling Report

ConocoPhillips

Bit # 5: 8 1/2" HTC MXL-28CHDX TFA: 0.746 in2, Jets: 3 x 18	Last Casing : 10"Liner Set at : 13257ft
Serial no: 6065408	
Grading : 1-2-WT-A-E-I-NO-TD	Inflow test

Activity and Tool information		Remarks:
Start RIH:	12 Mar 08, 02:00	Drill well to TD.
Start drilling:	12 Mar 08, 18:30	
Drilling completed at:	14 Mar 08, 08:05	
OOH at:	14 Mar 08, 22:40	
Motor Assembly:	No	
Revs Per Gallon:	NA	
Bend Angle:	NA	

SECTION AVERAGES

	Min:	Max:	Avg:
RPM string	76	140	122
RPM total	76	140	122
WOB	17.2	35.7	28.9
Flow	489.9	524.9	499.6
SPP	1902	2339	2287
TRQ	9048	12919	11341

To be filled in when finished drilling

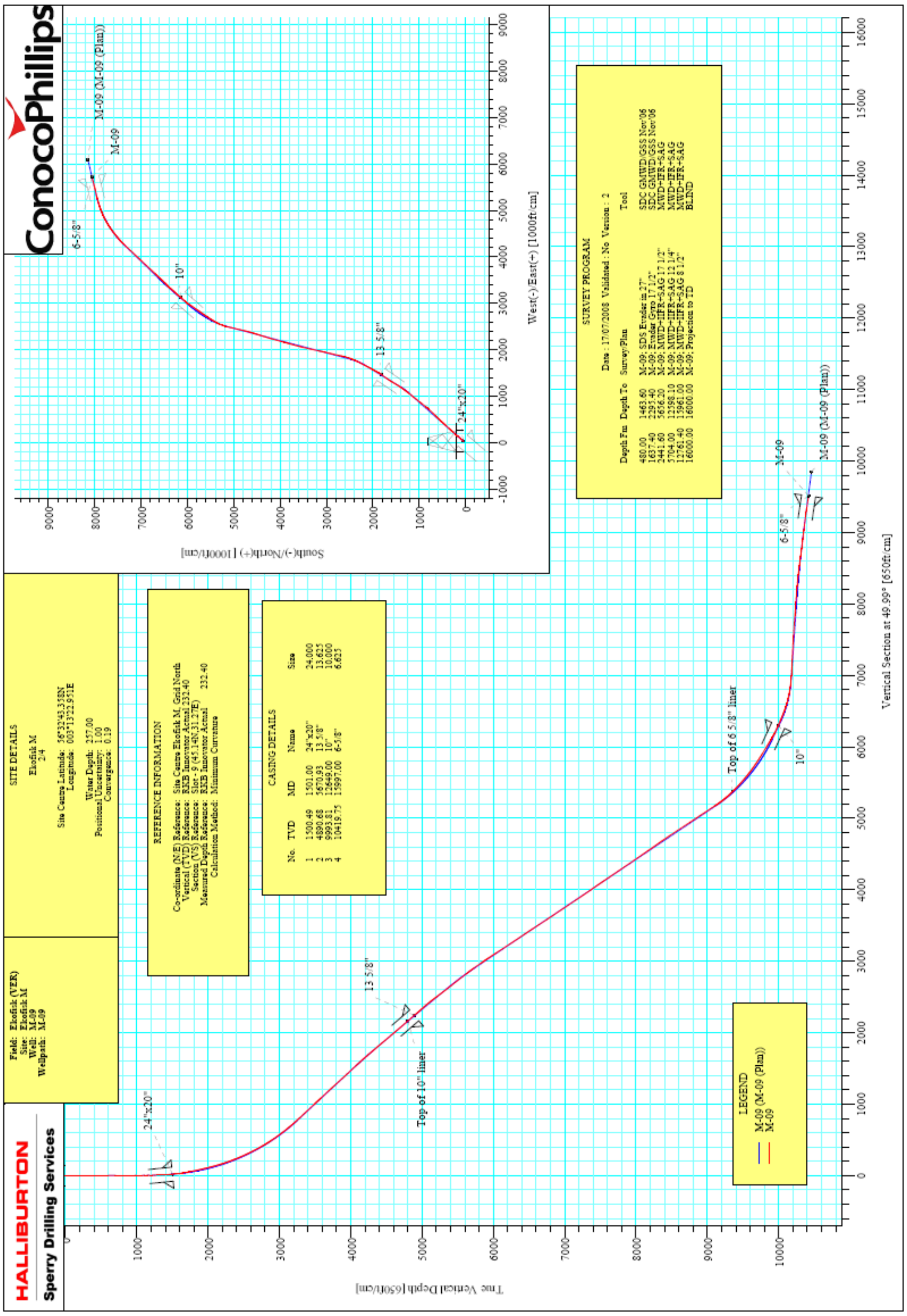
In at:	13369		12-Mar-08	13-Mar-08	14-Mar-08
Out at:	14023	Cumulative:	Daily	Daily	Daily
Midnight Depth MD			13438	13941	14023
Rotating Drilling Hrs on Btm		27.2	3.6	17.0	6.6
Sliding Drilling Hrs on Btm		0.0	0.0	0.0	0.0
Tot. HOB on form.		27.2	3.6	17.0	6.6
RIH		8.0	8.0	0.0	0.0
POOH		14.6	0.0	0.0	14.6
OOH/m.u. BHA		0.0	0.0	0.0	0.0
Others (drill cmt, cond mud, cnx., etc.)		18.9	10.4	7.0	1.5
Total Daily Hours		68.7	22.0	24.0	22.7
Connections number of		5	1.0	3.0	1.0
Total Connection Time mins		63.0	11.0	32.0	20.0
Average Connection Time		12.6	11.0	10.7	20.0
Total Circulation Hrs		45.4	11.3	23.8	10.3
Total Bit Revs, Krevs (on&off)		269.7	59.0	146.5	64.2
Motor Revs On Btm, Krev		0.0	0.0	0.0	0.0
Motor Revs Off Btm, Krev		0.0	0.0	0.0	0.0
String Revs on Btm, Krevs		188.3	25.0	120.5	42.8
String Revs off Btm,Krevs		81.4	34.0	26.0	21.4
Off btm string rot hrs		14.9	7.1	3.8	4.0
Bit Wear Index, Klb Revs / 1000		5675.9	703.0	3510.2	1462.7
Total Feet Drilled		654.0	69.0	503.0	82.0
Rotating Feet Drilled		654.0	69.0	503.0	82.0
Sliding Feet Drilled		0.0	0.0	0.0	0.0
Rotating avg ROP, ft/hr		24.0	19.2	29.6	12.4
Sliding ROP, ft/hr		0.0	0.0	0.0	0.0
Total ROP, ft/hr		24.0	19.2	29.6	12.4

Note: Connection time is time taken from pumps off until tagging bottom on new stand
Stand length is 132.7 ft. (3 long joints per stand)

Appendix E Case 4: M-9

The data given in appendix E are information regarding M-9.

E-1 Directional Data



E-2 Bit Report

HALLIBURTON
Sperry Drilling Services

2/4-M-9 Daily Drilling Report

ConocoPhillips

Bit # 4RR: 8 1/2" Hughes HCM607Z, TFA: 0.773 in2, Jets: 7 x 12,
Serial no: 216527

Grading : 1-1-WT-A-X-I-NO-TD

Last Casing : 9 7/8" Liner set at 12649 ft MD

Activity and Tool information	
Start RIH:	13 July 08, 22:50
Start drilling:	14 July 08, 11:05
Drilling completed at:	16 July 08, 13:35
OOH at:	17 July 08, 11:15
Motor Assembly:	No
Revs Per Gallon:	Na
Bend Angle:	Na

Remarks:
Drilled well to TD.

SECTION AVERAGES

	Min:	Max:	Avg:
RPM string	93	150	142
RPM total	93	150	142
WOB	0.9	27.5	12.0
Flow	458	602	596
SPP	1605	3310	3066
TRQ	9487	18354	14548

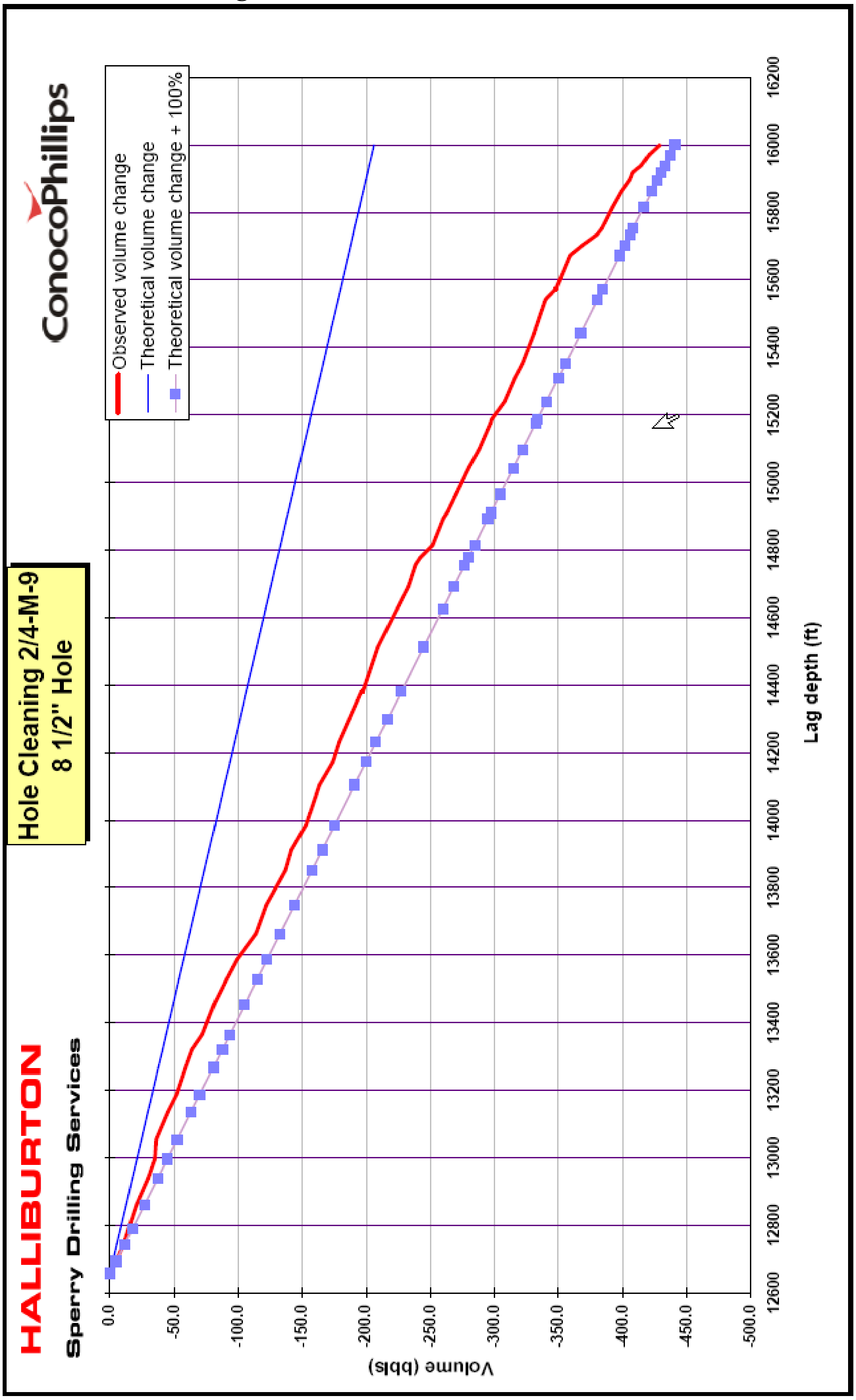
To be filled in when finished drilling

In at:	12657		13-Jul-08	14-Jul-08	15-Jul-08	16-Jul-08	17-Jul-08
Out at:	16000	Cumulative:	Daily	Daily	Daily	Daily	Daily
Midnight Depth MD			12657	13453	15268	16000	16000
Rotating Drilling Hrs on Btm		29.1	0.0	8.0	12.9	8.2	0.0
Sliding Drilling Hrs on Btm		0.0	0.0	0.0	0.0	0.0	0.0
Tot. HOB on form.		29.1	0.0	8.0	12.9	8.2	0.0
RIH		9.2	0.0	9.2	0.0	0.0	0.0
POOH		17.6	0.0	0.0	0.0	6.3	11.3
OOH/m.u. BHA		2.1	1.1	1.0	0.0	0.0	0.0
Others (drill cmt, cond mud, cnx., etc.)		26.4	0.0	5.8	11.1	9.5	0.0
Total Daily Hours		84.4	1.1	24.0	24.0	24.0	11.3
Connections number of		26.0	0.0	7.0	13.0	6.0	0.0
Total Connection Time mins		245.0	0.0	68.0	120	57	0
Average Connection Time		9.4	0.0	9.7	9.2	9.5	0.0
Total Circulation Hrs		61.2	0.0	14.4	22.6	20.9	3.3
Total Bit Revs, Krevs (on&off)		382.5	0.0	78.6	151.1	138.9	13.9
Motor Revs On Btm, Krev		0.0	0.0	0.0	0.0	0.0	0.0
Motor Revs Off Btm, Krev		0.0	0.0	0.0	0.0	0.0	0.0
String Revs on Btm, Krevs		244.6	0.0	59.9	110.9	73.8	0.0
String Revs off Btm,Krevs		137.9	0.0	18.7	40.2	65.1	13.9
Off btm string rot hrs		21.9	0.0	3.9	6.7	8.2	3.1
Bit Wear Index, Klb Revs / 1000		2706.7	0.0	793.4	1274.8	638.5	0.0
Total Feet Drilled		3343.0	0.0	796.0	1815.0	732.0	0.0
Rotating Feet Drilled		3343.0	0.0	796.0	1815.0	732.0	0.0
Sliding Feet Drilled		0.0	0.0	0.0	0.0	0.0	0.0
Rotating avg ROP, ft/hr		114.9	0.0	99.5	140.7	89.3	0.0
Sliding ROP, ft/hr		0.0	0.0	0.0	0.0	0.0	0.0
Total ROP, ft/hr		114.9	0.0	99.5	140.7	89.3	0.0

Note: Connection time is time taken from pumps off until tagging bottom on new stand

Stand length is 132.7 ft. (3 long joints per stand)

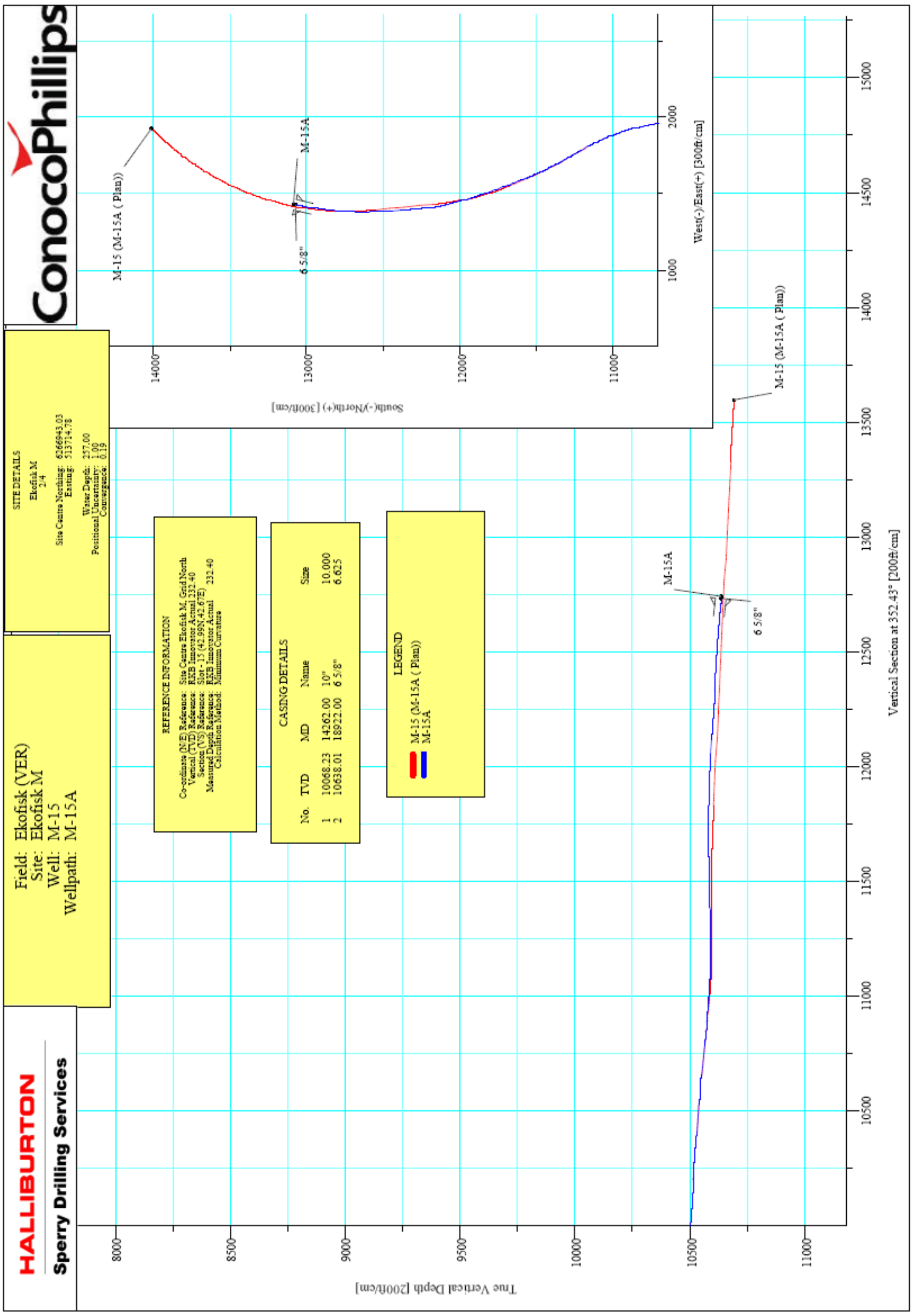
E-3 Hole Cleaning



Appendix F Case 5: M-15 A

The data given in appendix F are information regarding M-15 A.

F-1 Directional Data



F-2 Bit Report

HALLIBURTON
Sperry Drilling Services

2/4-M -15 Daily Drilling Report

ConocoPhillips

Bit # 4: 8 1/2" Hughes Christensen, HCM 607, TFA: 0.7731 in2, Jets: 7 x 12,
Serial no: 7205133

Grading : 1-2-WT-A-X-1-CT-DTF

Last Casing :
9 7/8" Liner Set at :
14262 ft

FIT: 16.0 ppg EMW

Activity and Tool information	
Start RIH:	05 Dec 06, 13:30
Start drilling:	06 Dec 06, 07:35
Drilling completed at:	09 Dec 06, 19:30
OOH at:	11 Dec 06, 03:00
Motor Assembly:	no
Revs Per Gallon:	n/a
Bend Angle:	n/a

Remarks:
Tagged cement @ 14168 ft. Drilled 95 ft float / cmt / shoe and shoetrack in 1.8 hrs.

SECTION AVERAGES	Min:	Maxi	Avg:
RPM string	99	151	142
RPM total	99	151	142
WOB	0.0	38.6	14.1
Flow	312.2	657.6	651.6
SPP	1477	3307	3937
TRQ	11328	19947	14326

To be filled in when finished drilling

In at:	14263		05-Dec-06	06-Dec-06	07-Dec-06	08-Dec-06	09-Dec-06	10-Dec-06	11-Dec-06
Out at:	19921	Cumulative	Daily	Daily	Daily	Daily	Daily	Daily	Daily
Midnight Depth MD			14263	14932	17063	18735	19921	19921	19921
Rotating Drilling Hrs on Btm		49.5	0.0	8.6	14.5	15.2	11.2	0.0	0.0
Sliding Drilling Hrs on Btm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tot. HOB on form.		**49.5**	**0.0**	**8.6**	**14.5**	**15.2**	**11.2**	**0.0**	**0.0**
RIH		9.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0
POOH		20.0	0.0	0.0	0.0	0.0	0.0	17.0	3.0
OOH/m.u. BHA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others (drill cmt, cond mud, cnx., etc.		55.6	2.0	15.4	9.5	8.8	12.9	7.0	0.0
Total Daily Hours		**134.1**	**11.0**	**24.0**	**24.0**	**24.0**	**24.1**	**24.0**	**3.0**
Connections number of		39.0	0.0	1.0	16.0	12.0	10.0	0.0	0.0
Total Connection Time mins		379.0	0	9	157	133	80	0	0
Average Connection Time		**9.7**	**0.0**	**9.0**	**9.8**	**11.1**	**8.0**	**0.0**	**0.0**
Total Circulation Hrs		103.5	3.4	21.7	21.2	23.0	22.0	12.2	0.0
Total Bit Revs, Krevs (on&off)		**550.5**	**0.0**	**69.8**	**132.5**	**154.9**	**146.0**	**47.3**	**0.0**
Motor Revs On Btm, Krev		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Motor Revs Off Btm, Krev		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
String Revs on Btm, Krevs		407.5	0.0	58.0	121.8	128.3	99.4	0.0	0.0
String Revs off Btm,Krevs		143.0	0.0	11.8	10.7	26.6	46.6	47.3	0.0
Off btm string rot hrs		34.1	0.0	3.3	3.4	5.0	9.8	12.6	0.0
Bit Wear Index, Klb Revs / 1000		6148.1	0.0	1227.9	1069.9	1732.8	2117.5	0.0	0.0
Total Feet Drilled		**5658.0**	**0.0**	**669.0**	**2131.0**	**1672.0**	**1186.0**	**0.0**	**0.0**
Rotating Feet Drilled		5658	0.0	669.0	2131.0	1672.0	1186.0	0.0	0.0
Sliding Feet Drilled		0	0	0	0	0	0	0	0
Rotating avg ROP, ft/hr		114.3	0.0	64.3	147.0	110.0	106.4	0.0	0.0
Sliding ROP, ft/hr		0.0	0	0	0	0	0	0	0
Total ROP, ft/hr		**114.3**	**0.0**	**64.3**	**147.0**	**110.0**	**106.4**	**0.0**	**0.0**

Note: Connection time is time taken from pumps off until tagging bottom on new stand
Stand length is 132.7 ft. (3 long joints per stand)

HALLIBURTON
Sperry Drilling Services

2/4-M -15A Daily Drilling Report

ConocoPhillips

Bit # 5: 8 1/2" Hughes Christensen, HCM 607, TFA: 0.76 in2, Jets: 4 x 11, 3 x 13
Serial no: 7204104

Grading : 1-0-WT-C-X-I-NO-TD

Last Casing : 9 7/8" Liner Set at : 14262 ft	
FIT:	

Activity and Tool information		Remarks:
Start RIH:	11 Dec 06, 03:30	8.5" Open hole sidetrack from M-15. Kick off at 16958 ft MD.
Start drilling:	12 Dec 06, 15:10	
Drilling completed at:	15 Dec 06, 08:40	
OOH at:	16 Dec 06, 17:00	
Motor Assembly:	no	
Revs Per Gallon:	n/a	
Bend Angle:	n/a	

SECTION AVERAGES	Min:	Max:	Avg:
RPM string	100	180	150
RPM total	100	180	150
WOB	7.3	42.9	23.9
Flow	550	662	647
SPP	545	3562	3213
TRQ	12241	20819	16697

To be filled in when finished drilling

In at:	16959		11-Dec-06	12-Dec-06	13-Dec-06	14-Dec-06	15-Dec-06	16-Dec-06	
Out at:	18932	Cumulative	Daily	Daily	Daily	Daily	Daily	Daily	
Midnight Depth MD			19921	16959	17315	18214	18932	18932	
Rotating Drilling Hrs on Btm		33.3	0.0	3.3	16.0	8.2	5.8	0.0	
Sliding Drilling Hrs on Btm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Tot. HOB on form.		33.3	0.0	3.3	16.0	8.2	5.8	0.0	
RIH		22.5	20.5	2.0	0.0	0.0	0.0	0.0	
POOH		37.2	0.0	4.0	0.0	0.0	16.2	17.0	
OOH/m.u. BHA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Others (drill cmt, cond mud, cnx., etc.		40.5	0.0	14.7	8.0	15.8	2.0	0.0	
Total Daily Hours		133.5	20.5	24.0	24.0	24.0	24.0	17.0	
Connections number of		16.0	0.0	0.0	4.0	7.0	5.0	0.0	
Total Connection Time mins		163.0	0	0	30	79	54	0	
Average Connection Time		10.2	0.0	0.0	7.5	11.3	10.8	0.0	
Total Circulation Hrs		96.5	6.1	20.2	23.6	21.9	19.2	5.5	
Total Bit Revs, Krevs (on&off)		478.0	0.5	78.9	204.9	82.3	98.6	12.8	
Motor Revs On Btm, Krev		0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Motor Revs Off Btm, Krev		0.0	0.0	0.0	0.0	0.0	0.0	0.0	
String Revs on Btm, Krevs		296.4	0.0	23.8	146.9	73.3	52.4	0.0	
String Revs off Btm,Krevs		181.6	0.5	55.1	58.0	9.0	46.2	12.8	
Off btm string rot hrs		38.4	0.5	12.9	7.6	2.7	11.4	3.3	
Bit Wear Index, Klb Revs / 1000		4394.0	0.0	262.0	1225.6	1436.7	1469.7	0.0	
Total Feet Drilled		1973.0	0.0	3.0	353.0	899.0	718.0	0.0	
Rotating Feet Drilled		1973	0.0	3.0	353.0	899.0	718.0	0.0	
Sliding Feet Drilled		0	0	0	0	0	0	0	
Rotating avg ROP, ft/hr		59.3	0.0	0.9	22.1	110.2	0	0.0	
Sliding ROP, ft/hr		0.0	0	0	0	0	0	0	
Total ROP, ft/hr		59.3	0.0	0.9	22.1	109.6	123.8	0.0	

Note: Connection time is time taken from pumps off until tagging bottom on new stand
Stand length is 132.7 ft. (3 long joints per stand)

F-3 Hole Cleaning