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HALLIBURTON

The evaluation of the drillability of low ROP/ plastic shales in aqueous-based drilling fluids applications

by Joakim Stø Backlund

Abstract

As the age of petroleum is rapidly progressing forward, the need to drill deeper and more challenging wells to access and exploit oil and gas reservoirs is increasing. The industry is constantly being challenged to find new and better solutions to the problems that drilling these types of wells create, and one area in particular that has required a lot of research and development is the drilling of shale formations. Since shale formations make up more than 75% of all the drilled formations, and contribute to more than 90% of wellbore instability problems, it has been of everyone`s interest to develop new equipment and methods to try and solve these issues.

The solution to most of these problems has been to use an oil based mud (OBM) system when drilling through the different shale formations. The OBM effectively prevents any unwanted chemical reaction or swelling from occurring and helps maintaining a decent wellbore stability and ROP. The problem with using an OBM however is that it poses a severe environmental and economical threat. Due to strict national regulations, an unintentional spill caused by leakage in the system can become very costly.

Because of these issues operators have looked at other alternatives to the traditional OBM such as water based mud (WBM). The WBM is relatively cheaper compared to the OBM and it does not have the same types of health, safety and environment (HSE) problems. Cuttings can therefore, in some parts of the world, be dropped directly on the sea floor. This can be a great advantage in areas where cuttings transport through the riser up to the surface is difficult, and transporting contaminated cuttings to shore is expensive.

However, there is a downside with WBM systems when drilling in deep shale formations. The drilling rate drops dramatically and very little progress is made. Even though the problem is known by the industry, the actual cause of the problem is not. Several theories attempt to explain it and many possible solutions have been developed based on them. The study of these theories, suggested solutions and real well cases with low drilling rate problem in shale formations has yielded some interesting results. Based on the real well case studies, parameters such as the weight of the drilling fluid, its flow rate, drilling fluid additives, drill bit type and drill bit design all seem to have a significant role in affecting the drilling rate in deep shale formations. By considering the results obtained in this thesis and applying the suggestions in future well operations it could potentially be possible to improve the drilling rate and reduce costs.

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1. Introduction

The thesis paper topic is the evaluation of the drilling environment while drilling through deep low rate of penetration/plastic shale formations using water based drilling fluid system. Since drilling is my major, writing a thesis that focus on the evaluation of a drilling environment is of great interest. It gives me the opportunity to become a lot more familiarized with all the aspects of drilling a well.

During my years of studying, I have constantly been told not to use a water based drilling fluid system in shale environments. Shale is extremely reactive to water and can quickly start to swell, wash out or cave in. Negative effects on the rate of penetration while drilling is also a widely known phenomenon with the use of water based drilling fluids. It is therefore a great motivational factor for me to be a part of the movement to change this, and possibly help the industry to drill more cost efficient and spare the environment from any hazardous spillage of more toxic drilling fluids such as OBM.

There has been some research done on the believed causes of the greatly reduced rate of penetration in deep shale formations, and they will all be presented in this thesis as a theoretical background for the subject. It is important to note that these theories have not been proven as of yet because of the difficulty in replicating the downhole environment in a surface simulator. The equipment used to drill in these types of environment never show any signs as to what the possible causes are, so in order to possibly find and identify the problem a thorough case by case study is needed.

My intention is to present cases that are nearly identical in the use of equipment, mud system and type of formations drilled, but where the results have been drastically different. This way it is possible to detect important differences that might have affected the drilling rates and come up with suggestions on how and what to improve.

2. Introduction To The Basic Equipment Used While Drilling

This chapter will act as an introduction to the main equipment used in a drilling operation so that the papers and reports discussed later on are more easily understood. The included subjects are drill bits, bottom hole assemblies and finally mud and hydraulic systems. The first subject to be discussed is the drill bits.

Rollercone Bits

There are three main types of drill bits used in the petroleum industry today; rollercone, PDC and coring bits. The first bit type, the rollercone bit, was the first to be utilized in the drilling industry. A modern rollercone bit, Figure 1, has three cones rotating to crush the rock in front of it, but the very first only had two cones. This two-cone bit was invented in 1909 by H.R. Hughes and its purpose was to drill hard formations which previously had dramatically reduced the life time of the early bit types known as drag bits. The downside was that unlike the tri-cone shown in the figure to the right, the first rollercone bits did not have intermeshing of teeth, and so bit balling was a problem in softer formations. A long tooth rollercone bit for soft formations was introduced, but it also had problems with bit balling. This was however addressed 16 years later, in 1925, together with the addition of mud lubricated bearings.

Figure 1 A modern tri-cone rollercone bit (Source: Halliburton.com)

In 1951 the first bits with Tungsten Carbide Inserts were introduced, the same year the patent for tri-cone bits that had held back the development of these types of bits for years was released. Approximately 20 years later, in 1970, the tri-cone Mill Tooth and Insert Bits became the industry standard. Since then the main development has gone into designing and developing the bearings for the roller cones, as they are the main component limiting the lifetime of the bit.

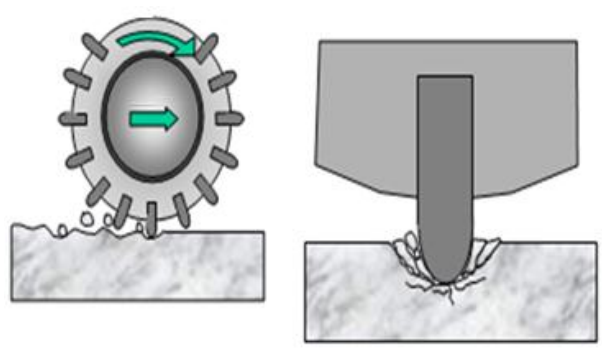


Figure 2 The rollercone crushing action (Source: UiS)

When the rollercone bit is lowered down to the formation and WOB is applied the inserts or teeth on the bit will crush the formation rock. Once the drill string is rotated the cones will start to rotate and continuously crush the formation when it comes into contact with it. This process can be seen in Figure 2. Once the rock has been crushed what happens next differs between the types of rollercone bits. If it is a Mill Tooth bit the teeth are long and will dig out more of the formation as it travel further, whilst for an Insert Bit designed for hard formations the inserts are short and blunt and will only crush the rock it comes into contact with and move on.

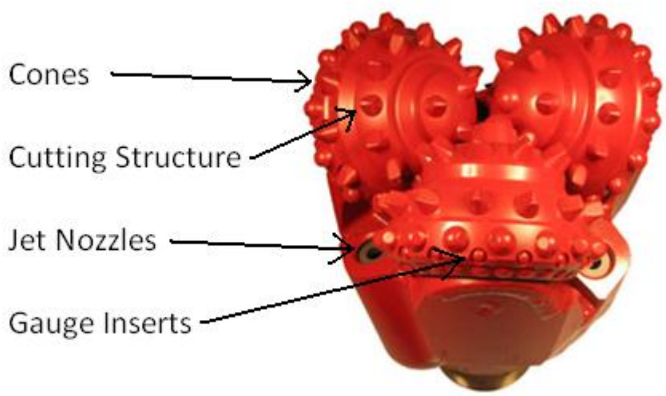


Figure 3 The major parts of a tri-cone bit. (Source: www.nov.com)

To lubricate, cool and clean the bit there are usually three jet nozzles strategically placed on the bit. Sometimes there is a fourth nozzle in the center, but this is not as common. The fluid pumped through the nozzles also generates a force that acts on the formation in front of it. This force will help the drilling operation if the formation is very soft, and it will effectively remove any cuttings away from the active drilling area. In addition there are inserts placed on the side of the cones to protect the bit from wear against the borehole wall, and to keep the drilled hole in gauge, hence the name gauge inserts. Figure 3 shows nicely the position of each major part of the tri-cone bit, apart from the bearings which are on the inside of the cones and therefore cannot be seen.

For the Insert Bits obviously the inserts used can be chosen based on the type of application the bit will be used for. For instance, if the formation is very hard, short and blunt cutters are inserted on the bit. These types of cutters only crush the rock in front of it and so the drilling rate will be relatively slow.

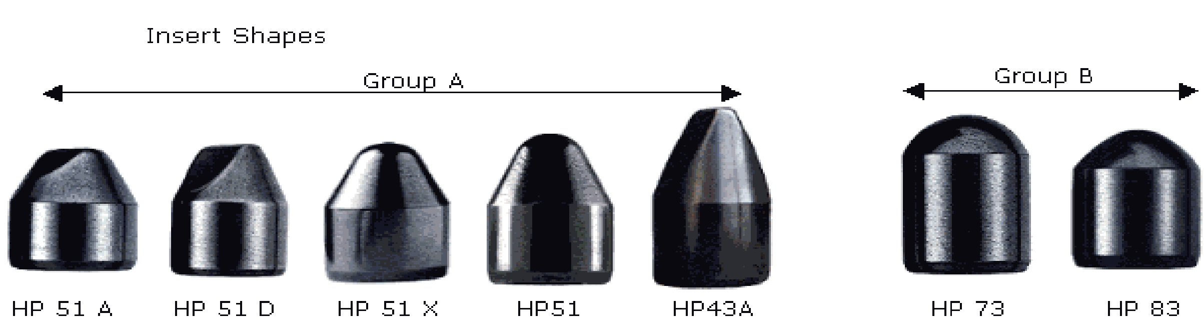


Figure 4 Rollercone inserts (Source: UiS)

However, it makes it possible to drill very hard formations and is therefore sometimes the only viable option. On the other hand, if the formation is soft longer cutters can be inserted instead. These cutters will in addition to crush the rock in front of it also dig out more formation as it travels further. This gives a higher penetration rate compared to the short cutters as it removes more rock with each rotation. The different inserts can be seen in Figure 4.

The most common applications for roller cone bits are drilling the top hole sections, casing shoes and formations where PDC bits would otherwise have difficulties drilling. Rollercone bits can easily be used together with downhole steering equipment as they usually have decent steerability. The drilling rates achieved are generally considered medium to slow based on other bit types, but they are often still the preferred choice. A major problem with the rollercone bits is the danger of losing one of the cones downhole while drilling. This can happen if the cone bearings fail during drilling. To retrieve the cone a fishing operation has to be performed, and if this is not successful special bits designed to drill out junk downhole known as Junk Mills has to be put to use. These are time consuming and expensive operations, and it is therefore very important to calculate the expected lifetime of the bearings accurately and continuously monitor the parameters affecting the bit while drilling.

Figure 5 Diamond bit (Source: www.nov.com)

PDC Bits

PDC bits, or Polycrystalline Diamond Cutter bits, has gradually taken more and more over for the rollercone bits in the petroleum industry. The first PDC cutters were introduced in the early 1970`s by General Electric. At the time the major rollercone companies showed little interest in developing this new type of bit, and so the very first designs of PDC bits were inspired by diamond bit design. Diamond bits, Figure 5, were used to drill hard formations, but as the PDC bit was introduced they became less and less common. All the major fixed cutter bit companies had commercial offering of PDC bits within the start of the 1980`s. In the industry the decade between 1978 and 1988 is known as the “heroic period” of PDC bit design.

Figure 6 Early PDC bit (Source: UiS)

Several new designs were tried out in the field during this period, and problems such as cutter breakage, cutter retention, body erosion and bit balling were difficult to overcome. Despite these problems some PDC bits performed exceptionally well, saving hundreds of thousands of dollars from the cost of drilling a developmental well. The first computer model for PDC bits to develop a force balanced cutting structure and to investigate temperature accelerated wear was developed by Sandia National Laboratories in the 1980`s. It was also during the 1980`s that Amoco Research discovered that most of the impact related wear occurring with PDC bits were caused by a phenomenon known as Bit Whirl. Since then one of the main research areas for PDC bits has been vibration reduction.

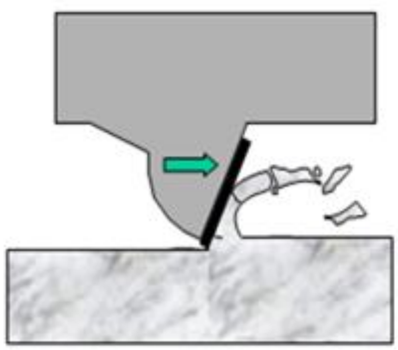


Figure 7 PDC cutters sheering action (Source: UiS)

Figure 6 shows an early type of PDC bit, and the resemblance to the Diamond bit is clearly visible. Compared to more modern PDC bits this one has a very simple design. It looks a lot more like a modern coring bit than a regular PDC drill bit. As mentioned before, a rollercone bit crushed the rock, but a PDC bit cuts the rock instead. This mechanism can be seen in Figure 7. The angle the cutter attacks the rock surface with is called the backrake angle, and it is this angle that dictates how aggressive the bit is. All PDC bits today have a negative backrake angle, but there have been development of new bits that have a positive backrake angle. That means that the cutters cutting surface will be pointing forward, creating a more scooping effect, compared to the regular cutting effect. A positive backrake angle will create an aggressive bit that can be very effective when drilling soft to medium formations.

Other factors that affect the aggressiveness of a PDC bit is the size of the cutters, type of cutter (round or scribe), amount of cutters and cutter profile. All these parameters are now designed in a computer program to match the expected environment so that the performance of the bit can achieve the optimal ROP.

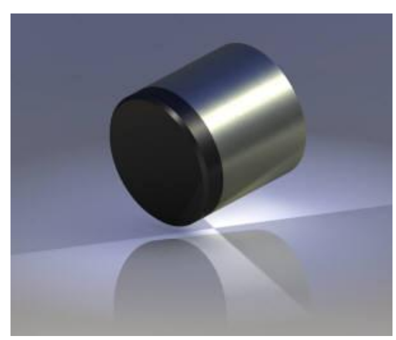


Figure 8 A round shaped PDC cutter (Source: www.shearbits.com)

The PDC cutters consist of two main components; tungsten carbide and a diamond table. To unify these two components into one part they have to go through a high-pressure and high-temperature process. Figure 8 to the right shows a complete PDC cutter with a round shape. A scribe cutter has only half the cutter shaped as a circle, whilst the other half has a triangle shape. This creates a much smaller cutting edge, but a lot more aggressive cutting compared to a normal round cutter.

By putting the carbide substrate and diamond grit into a container and applying 69 000bar at approximately 1500°C the two materials become sintered together. Materials such as cobalt alloy are also added to act as a catalyst for the sintering process. It also strengthens the connection between the diamond and the carbide substrate as it fills the gaps between the diamond crystals that are not filled by diamond growth during the sintering process. Originally the interface between the diamond and the carbide was only a flat surface, but later research into the thermal expansion of the different materials proved that this was not sufficient. A residual stress between the carbide substrate and the diamond table would make the cutter vulnerable and not able to withstand extremely abrasive formations or applications that included significant changes in formation strength. To improve the strength of this material bond a new surface on the carbide substrate was therefore developed. Instead of just a flat surface, grooves or claws was formed on the surface of the carbide substrate which substantially increased the strength of the material bond.

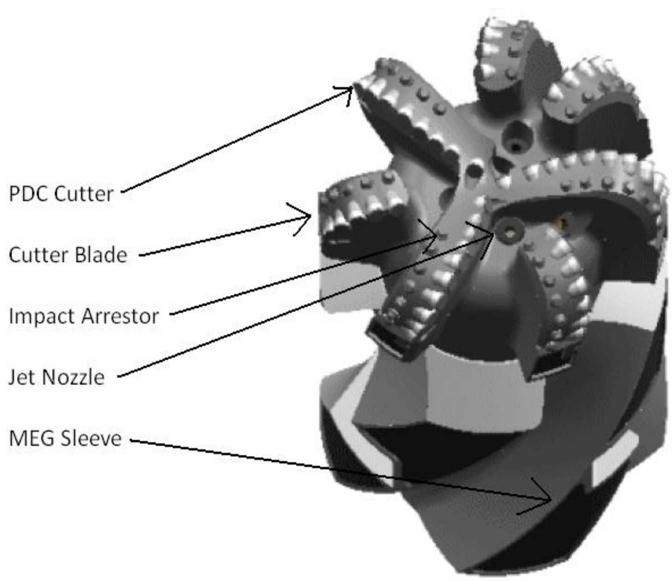


Figure 9 The major parts of a PDC bit (Source: Halliburton Database)

The PDC bits can be designed for a variety of applications such as soft to medium hard formations, steerable and rotary systems. Figure 9 to the left shows a bit designed for stability and steerability. It has 7 blades that make it less prone to vibrations and a phenomenon known as stick slip, whilst the long gauge behind it keeps in contact with the borehole wall making it easier to steer. The bit is also equipped with impact arrestors to absorb impact forces, and an anti-balling coating to prevent cut material from sticking to the bit surface.

The area between each blade is known as the junk slot area (JSA). For a PDC bit the JSA is what determines the size of the flow area, which is very important with respect to cuttings removal. The larger the JSA, the easier it will be to remove large and/or sticky cuttings. For instance, a PDC bit with 7 blades will have a smaller JSA compared to a 6-bladed bit and will therefore not be recommended if extremely efficient cuttings removal is needed. In addition the material the PDC bit body is made of also affects the JSA. A PDC bit usually has either a matrix body or a steel body. The matrix bodied bits are strong and have good abrasive resistance, but the material is brittle and the cutter blades have to have a certain thickness and depth. On the other hand, a steel bodied bit can have deeper and thinner blades but cannot handle very abrasive formations. Deep and thin blades are preferred when drilling in formations that tend to ball up on the bit as this maximizes the JSA.

A modern rollercone bit has cones that collectively remove any type of cut formation, but a PDC bit does not have this ability. Bit balling is therefore a much bigger problem for PDC bits compared to rollercone bits, and a lot of research and development has gone into improving bit and hydraulic design to optimize cuttings removal. One of the most important parts of the bit with respect to cuttings removal is the nozzle. When the nozzles are positioned in the optimal direction it is also possible to use different type of nozzles to create a preferred flow type out of the bit. For instance some nozzles can create a concentrated jet that can assist in the drilling operation, while others can induce a whirling motion that provides better cuttings removal due to an increase in turbulent flow.

Another important design aspect of the PDC bit is stability and force balance. Stability is achieved by minimizing bit whirl and stick slip. Bit whirl is lateral vibration that occurs when a bit drills an over-gauged hole and start to travel along the sides instead of drilling dead center. Stick slip is a torsional vibration that occurs when the bit gets stuck in the bottom formation and a torsional force builds up until the bit finally releases and spins quickly back to its natural position relative to the drill string. This torsional force can actually build up to become so large that when the bit spins back it ends up screwing itself off the drill string.

Designing for force balance means to take into account the distribution of the applied force on the bit and design it so the inevitable wear of the bit body and cutters are evenly distributed. By doing this the bit will be able to drill much further before it needs to be replaced, and it will drill more stable as well.

Figure 10 A PDC coring bit (Source image.china-ogpe.com)

Coring Bits

The third and final type of bit most commonly used is the coring bits. Coring bits are specifically designed for acquiring cylinder shaped cores of the formation downhole so it can be brought back to the surface for further study. A coring bit is either a PDC or diamond bit with a circular hole in the middle for the core to enter. Figure 10 shows a PDC coring bit from the side and top. The most critical design points of the coring bits is proper cooling of the bit, since the space for nozzles is limited, and making sure the wellbore fluid does not intrude the formation sample.

Bottom Hole Assembly

The bottom hole assembly is defined as every piece of equipment from the bit and up to where the standard drill pipe starts. This means bits, motors, rotary steerables, heavy weight drill pipes (HWDP), logging tools, jars and any other equipment that is needed for the drilling operation. The original purpose of the BHA was to provide adequate WOB while drilling since pushing the drill string would result in buckling. Buckling is when the drill string starts to bend downhole due to being in compression instead of tension, and it becomes twisted and ends up being supported by the borehole wall. When buckling occurs and the drill string comes into contact with the borehole wall the friction force greatly increase. It can make it impossible to continue drilling. With a properly designed weight on the BHA the drill string should always stay in tension with a designated WOB. The HWDP are usually what decides the total weight of the BHA, and they can be added or removed to optimize the WOB.

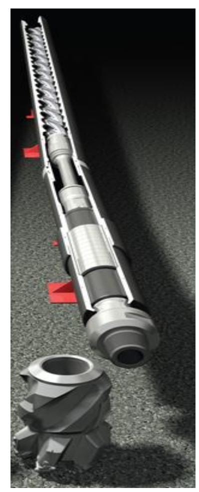


Figure 11 PDM (Source: www.halliburton.com)

When designing a BHA the HWDP are usually a standard that always have to be present, but every other equipment added can be decided based on the application it`s needed for. For instance if there is a danger of becoming stuck down hole due to hole stability problems a jar can force the BHA free again so that a hole opening operation can be performed. If the bit requires high RPM to drill properly, but the drill string rotation speed is limited, then a downhole mud motor can be added to the BHA. The mud motor is run by the pressure from the mud pumps on the surface, which creates a significant pressure drop that can cripple the hydraulic force at the bit. It is therefore very important to take this into account when designing the BHA. The two main types of downhole motors used in the industry today are Positive Displacement Motor (PDM), Figure 11, and Turbine Motor, with the PDM being the most common.

Figure 12 The Sperry Drilling GeoPilot® with Point-the-bit technology (Source: www.halliburton.com)

Another important BHA equipment that has become a lot more common in recent years is the rotary steerable systems (RSS) such as the GeoPilot® (Halliburton) and PowerDrive® (Schlumberger) systems. The principle of the steering mechanisms are either pointing the bit or pushing the bit in the desired direction. For instance, the GeoPilot® points the bit in the desired direction by bending the shaft at which the bit is connected to. The GeoPilot® is not rotating together with the drill string, but is kept in a stand still position by forcing wheels into the formation. This makes it possible to keep the shaft inside bent correctly and pointing the bit constantly at the correct direction. Figure 12 shows an exterior view of the GeoPilot®.

The shaft inside the RSS tools body is relatively weak, and cannot handle the force needed to be applied to the bit while drilling. It is therefore designed so that the weight applied is transferred from the BHA behind the tool over to the outer part of the body, and later transferred back to the bit at the end. This way the force applied does not buckle and destroy the shaft, and instead only affect the outer part of the tools body which is designed to handle the high weight.

The second type of rotary steerable, based on the push-the-bit principle, forces the bit into the desired direction. This is done by having a controller on the inside of the rotary steerable tool that forces one of three pistons to push out just at the right moment so that the body of the tool and the bit gets pushed in the designated direction. For this to be possible the body of the tool has to rotate with the drill string, unlike with the point-the-bit technology where the body has to be kept in a set position. Figure 13 shows a RSS with push-the-bit technology.

Figure 13 Push-the-bit RSS (Source: www.epmag.com)

As the tool rotates a controller directs the mud flow in the direction decided by the driller, and the pistons will travel back and forth between the formation wall and the tool as the fluid flow behind them gradually increases and decreases. A spring on the inside of the piston forces it to move back into the tool as the pressure is released. Since a pressure is needed to push out the pistons there will be a significant pressure drop over the tool that has to be taken into account when choosing which type of RSS one wants to use. The pressure drop over a point-the-bit RSS is regarded as the same as a normal drill pipe when it comes to pressure drop calculations.

Heavy weight drill pipes are a vital part of the BHA assembly since it generates the WOB. The amount of HWDP used in a BHA varies from operation to operation. Since it essentially is a standard drill pipe with thicker walls, the inside of the pipe is free from obstacles and the pressure drop is calculated as if it was a normal drill pipe. The HWDP should therefore normally not affect the drilling performance in any negative manner.

Other equipment such as logging tools and jars are also designed in such a way that they do not require pressurization from the mud, nor is the friction coefficient inside the tools any higher than that of a regular drill pipe. The only thing that can affect the pressure drop with respect to logging tools is the amount of tools used in the BHA. There are several types of tools such as gamma ray logger, sonic logger and resistivity logger etc. that can be used simultaneously in one BHA, and the pressure drop at the BHA could therefore increase or decrease based on the amount of logging tools used. It is however in a global drill string point of view irrelevant since the pressure drop can be considered equal to that of a regular drill pipe.

Drilling Fluids

Drilling fluid, or mud, is the fluid used to fill the drilled out hole while drilling, and can be divided into three main types, OBM, SBM and WBM. An OBM uses oil as its base fluid, a SBM uses a synthetic oil as its base fluid, while a WBM uses water as its base fluid. The primary objective of a drilling fluid is to act as a primary barrier element by providing a hydrostatic pressure in the well that keeps any lighter fluids in the formations out of the well, but it also fulfills many other important tasks for the drilling operation. Cooling and lubricating the bit, cuttings transport out of the well and keeping the cuttings in suspension when pumping of the fluid has stopped are three of these important tasks.

The drilling fluid also has to be designed in a way that minimizes formation damage, keeps the wellbore stable and in gauge and assists the drill bit in achieving a decent ROP. Based on an estimated pore pressure gradient for the formations that will be drilled, a certain mud weight is chosen. The weight of the base fluid is usually not enough to reach the needed mud

Figure 14 Barite mineral rock (Source: folk.ntnu.no)

weight, and weighting agents such as the barite mineral, $BaSO_4$, is therefore added to the mix. It is however very important that the mud weight is below the formations fracture gradient, since fracturing the formation can create significant downhole problems. On the other hand, if the pore pressure exceeds the mud weight the fluid from the formation will start to flow into the wellbore and up to surface. That is known as a kick and can be very dangerous if not responded to correctly. Figure 14 shows a barite mineral rock. This mineral can be used to raise the weight of both oil and water based drilling fluids.

In addition to the weighting agents, chemicals to help create a thin impermeable mud cake, increase or decrease viscosity, corrosion inhibitors, emulsifiers, ROP enhancers and shale stabilizers are also important additives that might need to be used. Which type of chemical that can be used, is based on the base fluid of the drilling mud. For instance, corrosion inhibitors are not needed for an OBM since it does not induce corrosion. Emulsifiers are not needed for WBM since its purpose is to reduce the interfacial tension between water and oil, and WBM does not include oil in its final mix. Different chemicals might be needed for the same purpose in the OBM and WBM since one type of chemical might not have the desired effect when the base fluid is oil, and vice versa.

Sometimes while drilling one might encounter a highly permeable formation, or create large cracks due to high mud weight, and the drilling fluid starts to flow out of the wellbore. If this happens fluid loss agents needs to be added to the drilling mud. Fluid loss agents, or lost circulation materials, are designed to be able to plug the area in which the mud flows out of the wellbore by following the stream and creating "bridges" over the pores of the formation. These materials can usually be used in all types of drilling fluids.

When it comes to shale formations, and preventing unwanted reactions, only the WBM systems encounter problems. OBM and SBM systems do not have the same issues with shale formations since the main source of the problem is water. When water comes into contact with reactive shales the borehole wall will become unstable and start to swell. Even a plastic behavior of the formation might be induced by water making it much more difficult to drill. A lot of research has gone into developing the perfect additive for drilling in shale environments, and even though there have been significant improvements, there are still many issues that haven't been resolved. The well can only be held stable for a certain amount of time, low ROP problems that do not occur when using OBM or SBM, and problems with bit balling.

Hydraulics

Figure 15 Mud pump (Source: image.made-in-china.com)

The drilling fluid is pumped downhole by a large mud pump at the surface, Figure 15. The mud pump generates the needed flow rate and pressure, but it can also limit the available flow rate and pressure for some operations. A decent flow rate is mandatory to properly remove the drilled cuttings downhole and transport it to the surface. If the cuttings do not get removed they can start to accumulate and create downhole problems such as stuck pipe and increased torque. Providing adequate pressure down to the bit nozzles is also very important since the hydraulic horsepower per square inch (HIS) through the nozzles is dependent on it. The HSI is the force of the jet from the nozzles and it can assist the bit in drilling the formation and also properly remove the cuttings.

Another element that can limit the hydraulic horsepower down at the bit is the drill string. The pressure drop over the drill string can become significant if the well being drilled is very deep. A normal drill string will have a 5” OD with a 4.276” ID. To decrease the pressure drop over the drill pipe the ID has to be increased. By using a tapered drill string, Figure 16, it is possible to increase the ID of the string without sacrificing the strength of the drill pipe.

The total pressure drop over the drill pipe and the bit is known as the stand pipe pressure, or SPP, and is the pressure from the fluid felt at the surface. It is also the pressure the surface equipment placed before the drill string, such as the mud motor, has to be able to handle. In very deep wells the surface equipment can therefore also limit the HSI since it limits the available pressure at the bit. Using the previously mentioned tapered drill string will reduce the SPP and thereby allow for more of the applied pressure at the top to reach the bit without risking catastrophic damage to the surface equipment.

These are some of the main equipment used in a drilling operation that are related to previously mentioned subjects such as bits, BHA, mud and hydraulics. A drilling operation is very complex, and therefore requires more equipment than what is mentioned in this chapter, but as an introduction to the basics of this type of operation the most important parts with respect to this thesis are introduced. The information in this chapter has been gathered from both presentations from the University of Stavanger[16] and Halliburtons own training manuals for rollercone[17] and PDC[18] bits.

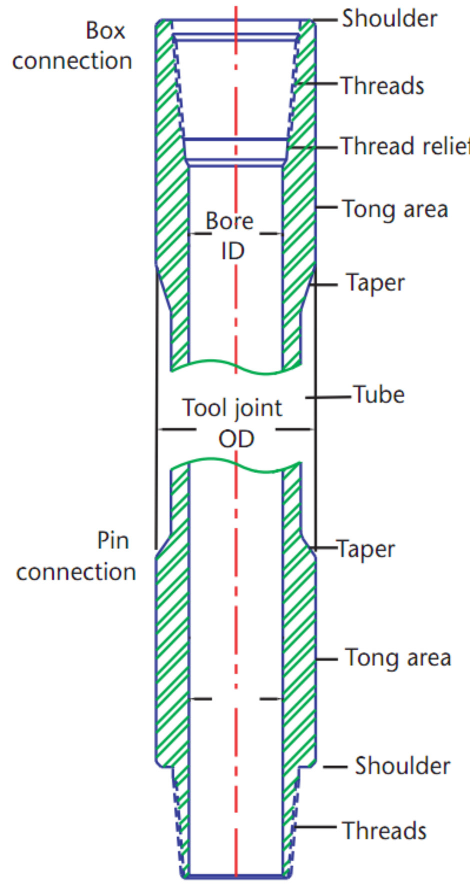


Figure 16 A tapered drill pipe (Source: www-odp.tamu.edu)

3. Theories On The Low ROP Causes

There exist several theories as to why there is a problem with low ROP when drilling deep shale formations using a WBM system. The following chapter will contain most of these theories and try to give a short and understandable description of each one.

3.1. Balling

Balling is considered by many as the main cause of the low ROP problem while drilling deep shale formations. There are three known ways the cut formation can ball up downhole. Either it balls up on the bit itself, which can happen in two ways; global balling or cutter balling, or it balls up at the bottom of the well, simply known as bottom hole balling. Following is a brief explanation of these three phenomenons.

3.1.1. Global Balling

In the paper Smith 1998[11] the global balling phenomenon is defined as "massive balling or any large scale packing or jamming of cuttings between the bit body and the bottom of the hole". When drilling through shale formations, global balling is widely accepted as the major cause of poor bit performance. This type of balling however has only been proven for shallow shale formations as the balled up cuttings stay on the bit up to surface.

Figure 17 Partially balled up PDC bit (Source: Halliburton DBS)

Deeper shale formations show the same characteristics as experienced with balling in shallow shale, but when pulling the bit there are no sign of balling. The bit itself is usually completely clean and only shows minor signs of blade or cutter wear.

The problem with global balling in shallow shale formations has been somewhat overcome by using bladed PDC bits with high level of bit hydraulics, and inhibitive, low density, water based mud systems. In some cases this is not enough, and the bit still gets severely balled up. Figure 17 shows a partially balled up Halliburton DBS PDC bit used in a sticky clay formation. Because most of the junk slot area (JSA) is filled with shale cuttings, an increase in stand pipe pressure will be experienced. This pressure increase and the corresponding decrease in bit torque is a clear indication of a balled up bit. As the bit becomes balled up the cutters start to have very little contact with the formation surface that it's supposed drill through, and the forces applied to the bit, i.e. WOB, become largely distributed through the attached cuttings to the rock rather than via the cutter blades, which translates into decrease of drilling efficiency.

When drilling in deeper shale formations the same pressure increase and torque decrease is experienced. That is also why it is widely believed that the reason for having low ROP in deep shale is because of global balling. The fact that the bit itself is not balled up when it is returned to surface goes against the global balling theory. A theory as to why the bit returns clean to the surface is that the cuttings become wet while tripping out of the well, therefore ending up falling or washing off of the bit. Since it is very difficult to replicate the downhole environment in very deep well in a surface simulator, to prove that severe global balling is the cause of low ROP in deep shale formations is nearly impossible.

3.1.2. Cutter Balling

Another potential cause of the slow ROP problem in shale is cutter balling. It has been observed and described in several papers by the use of single cutter tests and full scale lab drilling tests. Smith 1998[11] describes it as "the accumulation and adhesion of cuttings, in the form of the sheared and deformed or pulverized rock, on the face of the PDC cutter". It occurs due to the low effective pore pressure and low permeability of shale. As the rock is sheared off by the bit cutters the differential pressure between the cuttings pore pressure and the mud weight forces the rock against the cutter. The same effect has also been observed while drilling other types of formations with fine grains and low permeability.

The cutter balling phenomenon will be perceived as if the bit itself has become dull. This is due to the cuttings accumulating on the cutter face and supporting some of the weight applied to the bit, thus acting as part of the cutters themselves.

A related problem is also discussed slightly in the paper Smith 1995[12]. In the metal industry balling is known to occur on a microscopic scale while machining ductile material. The cut material accumulates only on the tip of the cutter, and is called Built-Up-Edge or Micro Cutter Balling. Figure 18 shows how this occurs and affects the cutting action of the cutter. As you can see the cut material gathers at the tip of cutter and it therefore becomes the first part to act on the new surface.

One thing to note though is that the figure shows a cutter with negative back rake. This is not at all common to use in the drilling industry, but it is known that the phenomenon also can occur on bits with positive back rake cutters.

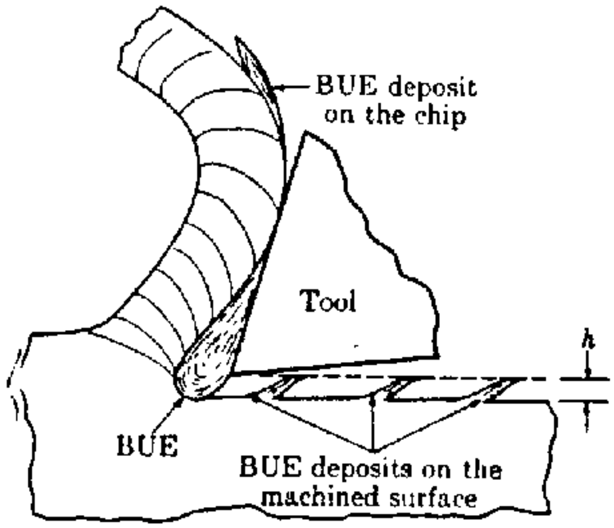


Figure 18 A schematic showing the BUE and how it forms on the cutters edge. (Source: web.mit.edu)

3.1.3. Bottom Hole Balling

The third problematic balling scenario is bottom hole balling. This phenomenon was described by Garnier & Van Lingen[19] as early as 1959. The theory behind it is that during drilling the cuttings and other debris will, in combination with solids from the drilling fluid, create an almost impermeable layer at the bottom of the well. Due to the high pressure in the well the layer will be forced against the bottom, and the bit will be forced to drill this layer of already cut rock again. In other words, it can be considered as a very hard mud cake that gets replenished with each revolution of the drill bit.

3.2. Confining Pressure Effects

During most drilling operations an overbalanced approach is taken. Meaning the mud weight is high enough to create a bottom hole pressure above the pore pressure in the formation. The effect this pressure difference has on the drilling rate as the depth increases has been studied for years and is recognized by the industry as a real problem.

The difference between the wellbore pressure and the formations pore pressure in front of the bit is known as the effective confining stress. This stress strengthens the rock, which in turn makes it harder to drill and reduces the ROP. In shale formations this effect is enhanced due to the rocks impermeability.

Lab tests performed by Zijsling[20], Kolle[21], and Gray-Stephens[22] have shown that the pore pressure in the shale actually drops to zero as the rock is cut by the bit. This happens due to dilation, and it essentially means that the confining stress for the shale is as great as the wellbore pressure. In other words, drilling deep shale formations with a high mud weight can reduce the ROP dramatically. Figure 19 shows how this phenomenon occurs during drilling.

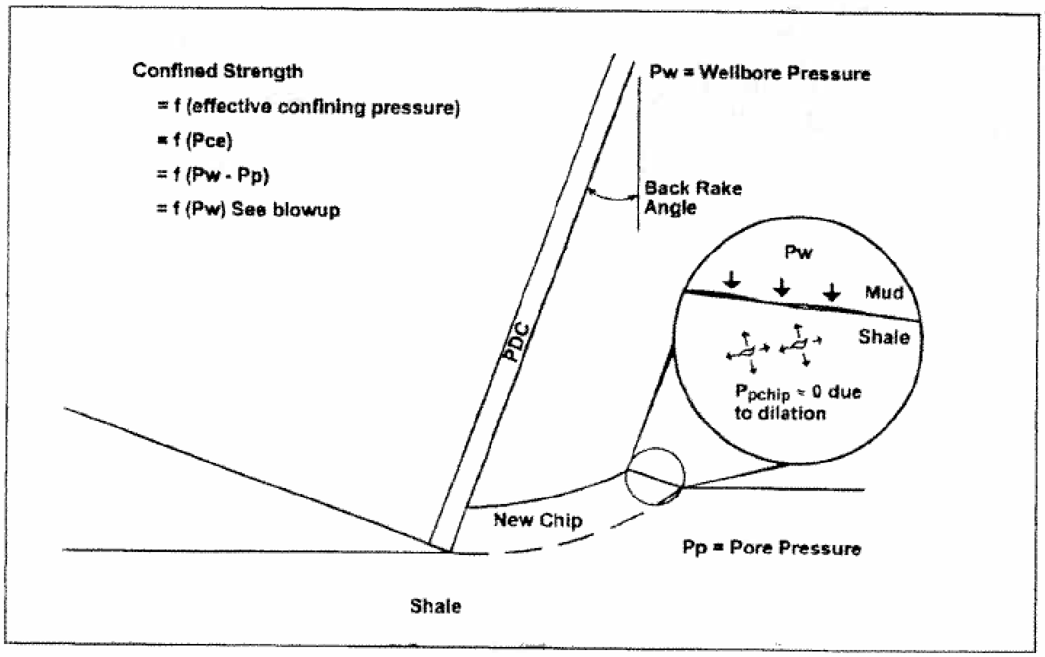


Figure 19 A schematic showing wellbore pressure acting as confining pressure (Source: Smith[11])

3.3. Chip Hold-Down

Another phenomenon studied by Garnier & Van Lingen[19]. It is somewhat similar to bottom hole balling, and it occurs when an impermeable rock is cut. The pressure below the chip does not have time to equalize due to the impermeability, and the wellbore pressure will therefore force the chip back onto the formation rock surface. This makes it much more difficult to remove cut formation and reach the new formation behind it.

It was first discovered to occur while drilling with rollercone bits, but Garnier & Van Lingen[19] later concluded that it could also decrease the performance of PDC bits.

3.4. Shale Plasticity

The shale can in itself become plastic. Once water comes into contact with the shale formation the water imbibes into the rock and creates a surface of plastic shale. This new layer on the surface of the rock will inhibit the PDC cutting action and severely reduce the drilling rate. It has also been confirmed by Cheatham & Nahm[23] that this happens with high mud weights for both water and oil based mud systems.

3.5. Smectite

The clay mineral group known as smectite is not mentioned specifically as the main mineral group creating low ROP issues in deep wells, but it was discovered to be the main clay mineral in the Zidane well. In the Zidane well severe low ROP problems occurred when a certain depth was reached, and the details of this will be further discussed later in the thesis. Since smectite is the only clay mineral present when the low ROP problems started it could be relevant to understand the build up and behavior of this reactive mineral group.

As mentioned smectite is not a mineral itself, but a mineral group consisting of montmorillonite, beidelite, nontronite, saponite, hectorite, sauconite and volkonskoite. Montmorillonite is the most common clay mineral of these and it is derived from an aluminumsilicate, see Table 1.

Table 1 A table showing the smectite minerals and their chemical build-up (Source: www.snl.no)

Aluminumsilicate	Al2Si4O10(OH) x H2O
Montmorillonite	Aluminum partly replaced by Magnesium and Silisium partly replaced by Aluminum
Beidelite	Aluminum replaces Silicon
Nontronite	Iron rich
Saponite	Magnesium and Iron in the solution
Hectorite	Magnesium and Litium in the solution
Sauconite	Contains Sink
Volkonskoite	Contains Chrome

Montmorillonite is built up by a layer lattice structure. If the mineral comes into contact with water or other positive ions they will be able to enter into these layers and make the mineral swell. The mineral is also the major component for bentonite, which is formed by the transformation of volcanic ash. Incidentally, bentonite is added to drilling fluids to improve the mud cake and reduce loss of filtered fluid to the formation.

An octahedral and a tetrahedron layer in alternating order are the main building blocks of the smectite minerals. In the octahedral layers the elements 0_2 and OH_- are tightly packed into two layers with equal distances to Al_{3+} or Mg_{2+}. Figure 20 shows the build-up of an octahedral layer. The name of the structure differs whether it is the aluminum or the magnesium element that is present; $Al(OH)_3$ is called gibbsite and $Mg(OH)_2$ is called brucite.

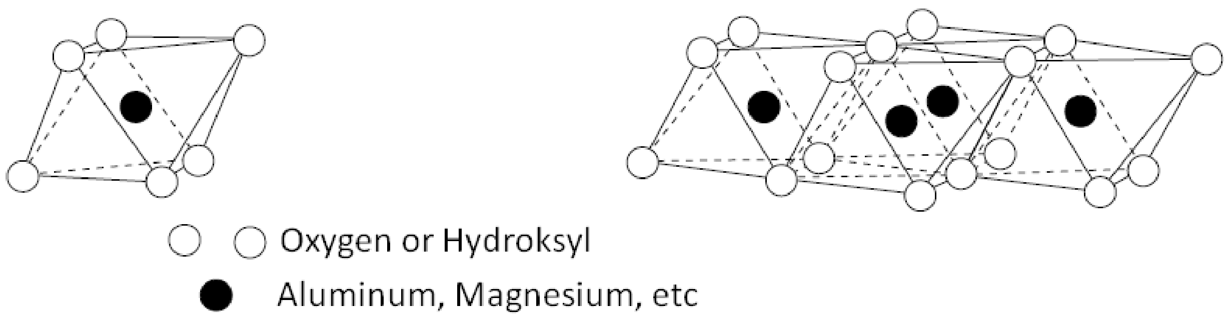


Figure 20 Smectite mineral octahedral layer (www.ux.uis.no)

The tetrahedron layers consists of silicon and oxygen or hydroxyl, with the silicon atom in the centre of the structure and 4 oxygen or hydroxyl atoms at equal distances around it. Figure 21 shows the tetrahedron structure. The composition of these elements in the tetrahedron structure is $Si_4O_6(OH)_4$.

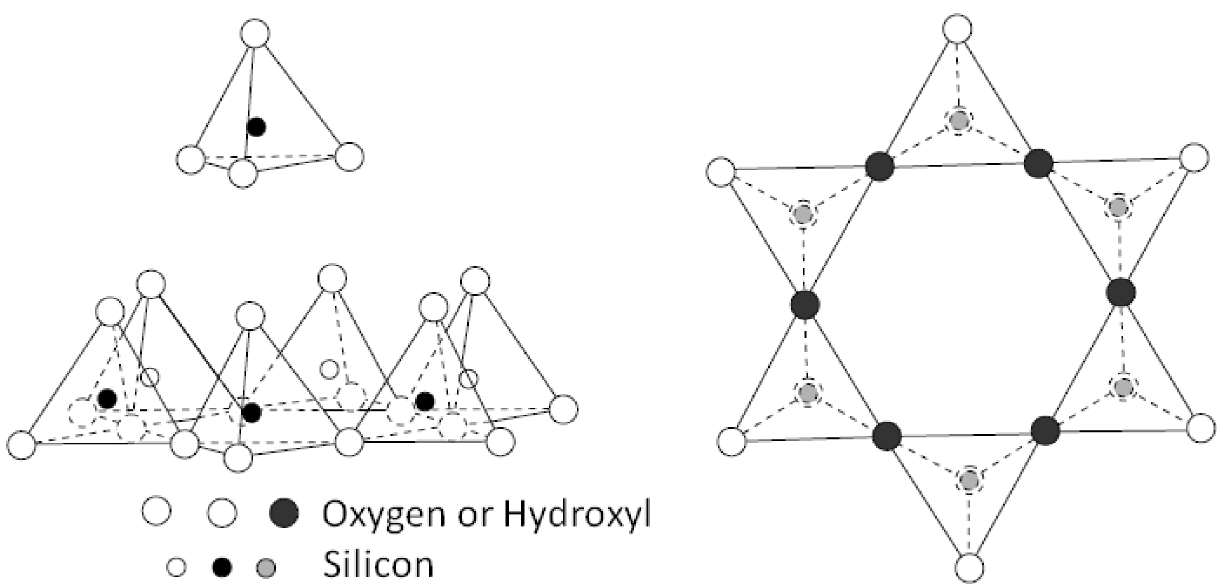


Figure 21 Smectite mineral tetrahedron layer (www.ux.uis.no)

On the right side of the figure one can see the hexagon structure built up by the tetrahedron layers. The many different clay minerals that exist are based on the different combinations of octahedral and tetrahedral layers bound together in crystal structures. This is possible due to the different layers ability to share either oxygen or hydroxyl with each other.

The swelling of these clay minerals occurs in the octahedral layer were a substitution of ions takes place. The cations trying to enter the structure are not able to properly reach the center, and are therefore not able to completely remove the minerals electric charge on the surface. This residual charge is what attracts polar molecules such as water, and what causes the swelling of the clay mineral.

The size of the mineral when it swells can vary greatly, and it is dependent on the type of cation absorbed on the mineral surface. For instance, a divalent cation such as calcium, Ca_{2+}, needs to be connected to two ions in the clay mineral, compared to a monovalent cation such as sodium, Na_{+}, which only needs to be connected to one ion. The sodium cation therefore creates a lot more surface area for the crystal-bound water to access, and as such the clay mineral swells to a greater size compared to that with a calcium cation. The difference in size is as great as 80-90% between the two.

The clay mineral can swell by two main mechanisms, either crystalline or osmotic. Crystalline swelling occurs when crystalline water molecules bind to the surface of the tetrahedral layer, but exactly how this happens is unknown. However, it has been agreed upon by scientists that this does in fact occur. Osmotic swelling occurs due to a difference in concentration of cations in the liquid within the crystal. This gives a difference in chemical potential, and the water will be forced to enter the clay mineral to equalize the potential. In crystalline swelling the water is better connected to the clay minerals compared to osmotic swelling.

As mentioned before the main cations absorbed on the mineral surface is either calcium or sodium. Since the calcium cation is connected with two ions between the crystal surfaces it has a much stronger connection, and the osmotic force is not strong enough to break this connection. For the sodium cation with only one cation connection the total swelling of the mineral is represented by 80-90% osmotic swelling. This is most relevant for the montmorillonite mineral, but also applies for the other minerals in the smectite group. Figure 22 shows a smectite rock with calcium cation absorbed on the surface giving it the color red.

Figure 22 Smectite rock with absorbed calcium cation (Source: http://homepage.ufp.pt/biblioteca/)

4. Possible Solutions To The Low ROP Problem

Low ROP in shale formations has been a problem for the industry for decades, and given the severe impact it has on well economics the industry has completed several research projects aimed at fixing the problem. These research projects have resulted in several interesting and even commercialized ideas that have shown interesting results both in the lab and out in the field. Ranging from advanced cutter design all the way to effective inhibitive drilling fluids, the results for several of these projects will be presented to get a clear view of what has been done and what has actually become a commonly used solution.

4.1. Polished PDC Cutters

One part of the bit which is often neglected when it comes to improving ROP in plastic shale formations is the cutters and their surface. The surface of the cutters is relatively smooth and has a very small friction factor, but to understand the possible problem one has to turn to the metal cutting industry. The previously mentioned concept of BUE has been identified and studied thoroughly in the metal industry, and it could quite possibly apply for the drilling industry as well. BUE is defined as a small amount of material that detaches from the cut formation and attaches to the leading-most edge of the cutter. This can also be addressed to as bit balling at the cutter tip on a microscopic scale. Because of the low friction of a non-polished cutter and its generally positive back rake position the BUE should not be able to form at all, but the theory is that the high density and high pressure in the borehole greatly increases the friction force. The increased friction force is what then helps generate the BUE and keep it in position. When machining ductile materials using a cutter in a negative backrake position, BUE is a common phenomenon. However, it is also possible for a BUE scenario to happen with the cutters in a positive backrake position such as on a PDC drillbit. Other factors that affect the BUE include adhesion, temperature, chip thickness, cutting speed, surface finish, and variations in mechanical properties of

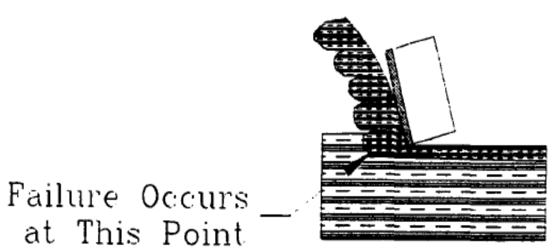


Figure 24 A cutter with Built Up Edge (Source: Smith[12])

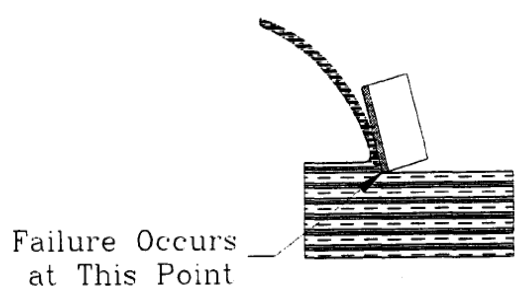


Figure 23 A cutter without Built Up Edge (Source: Smith[12])

materials. Figure 24 and Figure 23 shows the difference in cutting structure between a cutter with BUE and a cutter without.

As the BUE forms on the cutters the bits performance will become equal to that of a dull/worn bit. This is consistent with field observations where the bits used to drill plastic shale formations perform as if the cutters are dull/worn, yet when the bits are pulled they show little to no wear at all. The reason for the dull action of the cutter is that the BUE protects the cutting edge and prevents it from digging into the formation properly. In the metal cutting industry the problem has been dealt with by the use of lubricants and low-friction coating. Lubricants are already in use in the drilling industry, and it has not been deemed effective enough in real well cases. Low-friction coating however has been discussed by Mat 2002[14] as a possible solution to the low ROP/plastic shale problem, and will also be discussed later in this thesis. As of the time of writing of the paper currently being used as source of theory for this particular section, there didn't exist any type of low friction coating durable enough to withstand the harsh and hostile environment experienced downhole while drilling. The concept of highly polished cutting elements, or inserts, was therefore introduced by Smith 1995[12].

Generally the PDC cutters have a surface finish in the range of 20-40 microinches. This gives them a nice and smooth matte appearance. To test if the surface finish of the cutters had any effect on the drillability in plastic shales, several experiments were performed with cutters that had a surface finish of approximately 0.5 – 1.0 microinches. A cutter with these low surface finish values will become highly reflective, almost mirror-like, and be very smooth to the touch.

To determine the relative difference in friction characteristics between a polished and non-polished cutter two experiments where performed. One of the experiments is performed by putting the cutter with the diamond face down on top of a flat rock surface. By tilting the rock slowly, the angle at which the cutter starts to slide is noted. The second experiment is performed by pressing the cutter diamond face down on the rock surface and gently applying force to make it slide. The force needed to make the cutter slide is then noted. This gives relative differences that only have validity in comparison against each other because the friction coefficient is extremely sensitive to many other parameters that are not taken into account in these experiments. With that in mind, these experiments showed a decrease in friction coefficient of approximately 75%.

While these experiments seemed promising, more relevant lab tests where needed to be performed before the polished cutter theory could be implemented to real well situations. To get more relevant data, Single Point Cutter and Full-Scale Simulator tests where therefore undertaken. The tests were performed on several different types of shale formations, including Pierre, DeGray, and Catoosa. Results from these tests proved to be very promising, with a significant decrease in torque, WOB and tendency to ball up at the bit. The ROP was held constant, so the decrease in WOB showed that the polished cutters could drill faster with less WOB than the non-polished cutters. It is however important to mention that when drilling the Catoosa shale formation, no significant difference in performance between the polished and non-polished cutters was detected.

As most of the tests for the polished PDC bits gave positive results, real well tests were next. Five wells in the South Texas area with known plastic shale problems were selected for this. In three of the wells the polished PDC bit was not used until the standard PDC bit already in the hole started showing drilling rates deemed unsatisfactory. The polished cutter bits used in all three wells showed improvement compared to the previously used standard cutter bits, but at some points they didn't show any improvement at all. In one of the wells the polished cutter bit drilled at rates substantially higher than with the standard cutter bit, however, the penetration rate also dropped at times to that of the standard cutter bit in certain shale sections. The overall drilling performance was an improvement for the polished cutter bit.

In the last two wells a different experiment was performed. As these two wells were situated very close to each other it was planned to use opposite bit runs in them. Meaning, for one of the wells a polished cutter bit would be used for the first run, and a standard cutter bit for the second, while in the other well the opposite was done. This way it would be possible to compare the results with each other to determine if there were any significant improvements. Although some problems did occur while drilling the wells, global bit balling and a plugged nozzle, the polished cutter PDC bits needed less WOB to reach the same ROP as the standard bits, and they drilled either at the same ROP or faster.

These tests shows that polished cutters is definitely a possible remedial solution to the plastic shale problem, but it also shows that further development should be conducted to improve the results. Polished PDC cutters are not commonly used by the industry, but further studies should be performed to determine if the method is worth commercializing.

4.2. Low-Friction Bit Coating

The low-friction bit coating is designed to apply the surface of the bit with a thin and slippery coating layer that prevents the drilled formation from sticking to the bit, thus preventing bit balling. This is not a new way to prevent bit balling, it has been around for over 30 years, but it wasn't until about 9 years ago that a more reliable coating was developed. Up until then the types of anti-balling coating was ultra-smooth epoxy paint, rare metals, nickel plating and nitriding. All used with very little success. The new type of low-friction bit coating is documented by Mat[14], and is where the information in this chapter has been acquired from.

According to Mat[14], in 1938 engineers in DuPont accidently discovered the effective non-stick coating flouropolymer called Teflon. The use of Teflon as bit coating had been tested by Hughes Tool Co. and Christensen Diamond Products several times during a 20 year period, but no positive results were obtained. It wasn't until the year 2000 that they obtained successful results with the use of a newly developed coating process that utilizes a specially formulated, reinforced Teflon-like flouropolymer.

The different types of coating only attach to a surface mechanically, not chemically, and therefore it is only the roughness of the surface that keeps the relatively soft coating in place. When drilling with coated bits in hard formations the coating was peeled, scraped or eroded off very quickly. During a 3 year experimentation period a new process of coating the bit was developed that showed promising results.

By the use of proprietary additives the coating is given extraordinary toughness yet still retains all its non-stick properties. To keep the coating on the bit surface in very tough environments the bit itself also undergoes a special roughness process. The process creates a three-dimensional profile for the coating to grip, which together with a newly developed surface primer, creates an excellent bond between the coating and the bit. The aforementioned surface primer creates a chemical reaction that assists in the adhesion of the coating. The combined effort of a bit manufacturer and a commercial coating supplier was essential to obtaining the results showed by the developed product.

The new coating, and coating process, was put to the test in several relevant performance tests. The Single Point Cutter test, Baseline Full-scale Bit test and a simulator test with two commercial bits. First off was the Single Point Cutter test. It was performed in Catoosa shale using water as the drill fluid. The cutters were tested both with and without coating, and with several different commercial coatings. The test showed an improvement of up to 25% in forces applied compared to bare steel. These were promising results and an indication of how the coating might perform in more real well tests.

Next up was the Baseline Full-scale Bit test. To get relevant results from this test the drilling parameters were intentionally set at values that would promote bit balling. The Catoosa shale was again used as the formation to be drilled, force from the nozzles was set at 1.0 HSI and the bit was rotated with a speed of 240 RPM. To do the tests a 6-1/2" IADC M332 bit was selected, and the tests themselves were performed in a simulator located at a Hughes Christensen research facility. Again the results were promising, with a 400% improvement in ROP compared to a bare matrix baseline bit. Interestingly though, all bits with coating were partially or severely balled up at the conclusion of the tests, while the uncoated bit was fully balled up. It is interesting because the bits with coating still got balled even though they performed a lot better.

The last test was the full scale simulator tests with two commercial PDC drill bits sized at 8-3/4"(IADC M323 PDC Bit) and 8-1/2" (IADC M223 PDC Bit). Both of the coated bits pushed the simulator to its limits without experiencing any balling. The test was again performed in a Catoosa shale formation, and the WBM was weighted to 1.14sg. In this drilling environment the uncoated bit was able to reach 200 feet per hour (fph) before balling occurred. On the other hand, the coated bits reached the maximum ROP of the simulator at 270fph without any balling at all. Applying different weight on bit showed that the coated bits performed 25-50fph better than the uncoated bits.

When the mud weight was increased from 1.14sg up to 1.92sg the ROP of the uncoated bits dropped from 200fph down to 175fph and again ended with extensive bit balling. With the coated bits balling was prevented and a simulator maximum of 270fph was reached even with a very high mud weight. Historically very few bits have managed to reach this drilling performance in the simulator, so the test results showed very much promise for use of the

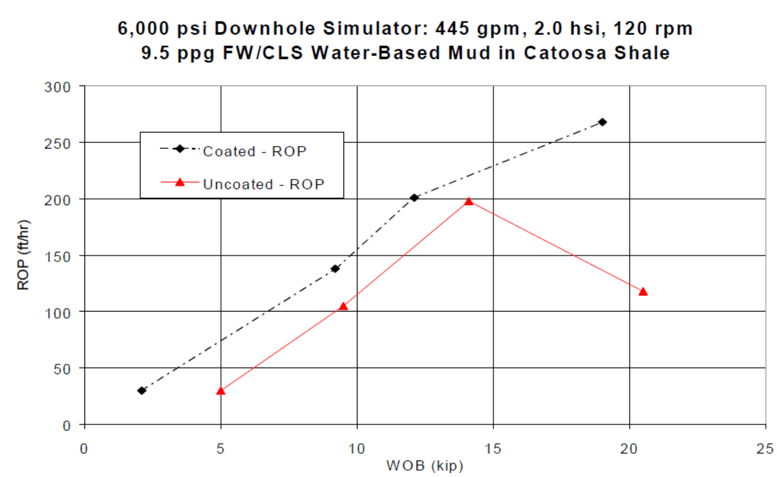


Figure 25 Performance of Coated vs. Uncoated 8-3/4" IADC M323 PDC Bit (Source:Mat[14])

coating in real well situations. Figure 25 and Figure 27 shows the obtained results for both the bits using ROP as a function of WOB.

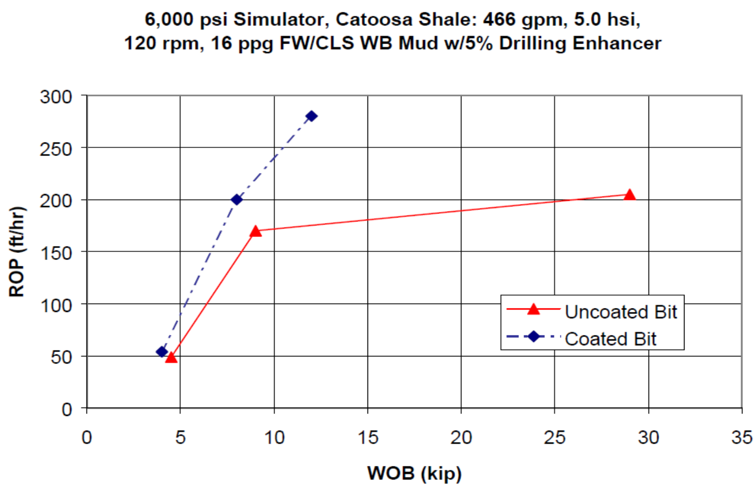


Figure 27 Performance of Coated vs. Uncoated 8-1/2" IADC 223 PDC Bit (Source: Mat[14])

The low-friction bit coating was put to the test in real well situations by Petronas Carigali offshore Malaysia. Petronas Carigali had experienced bit balling problems in several wells when drilling in formations below 8000ft with water based mud. They had previously had some success using a bit treated with a process involving surface electrical charge, and so they wanted to try other experimental bit treatments as well. The bit chosen for the live test was the IADC M323 PDC made by Hughes Christensen.

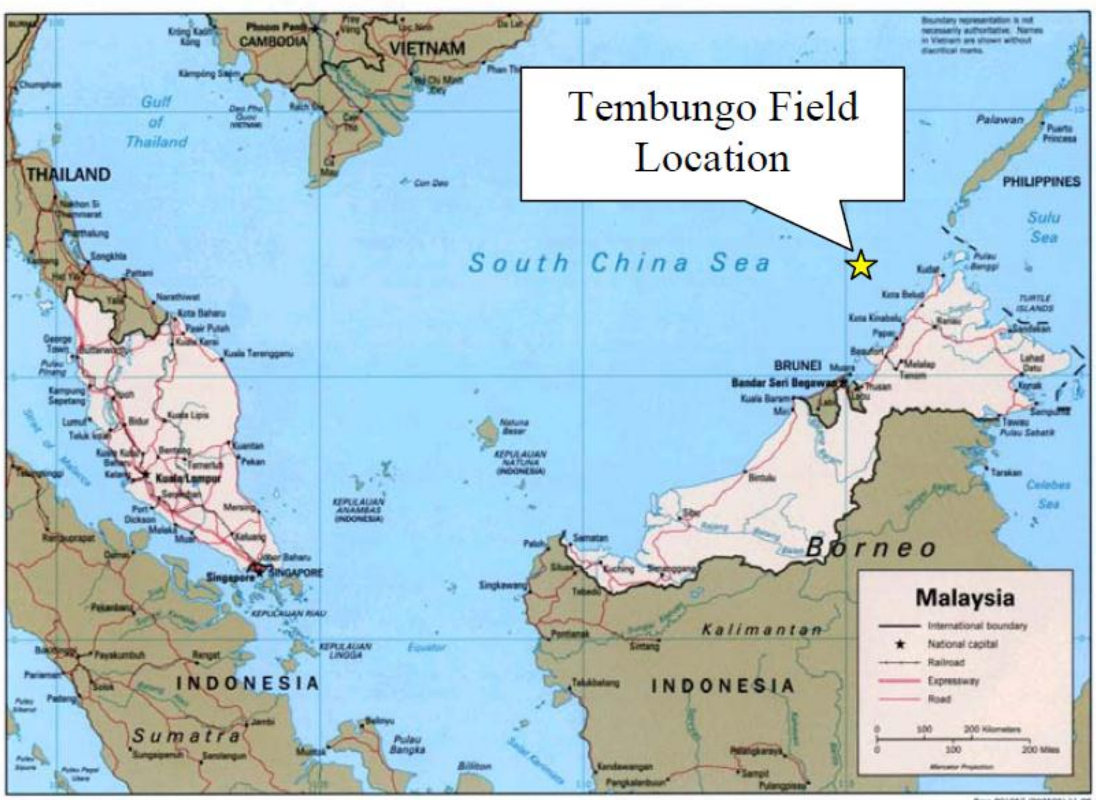


Figure 26 Map showing the location of the Tembungo field (Source: Mat[14])

The Tembungo field, shown in Figure 26, is situated 79 km northwest of the city of Kota Kinabulu on the island of Sabah (Borneo) in Malaysia. In 1993 a six-slot jacket was installed in the field, but the jacket was expanded in both 1995 and 2000 to a total of nine slots. In March 2000 the Tembungo B9 was spudded, and the reinforced flouropolymer coated PDC bit was put to use in the 12-1/4" section. The previous wells drilled on Tembungo had all experienced balling and low ROP below the 7800 feet depth mark. All wells used water based mud with high mud weights. Below 7800 feet TVD the ROP decreased as the depth increased. The 12-1/4" section was at first drilled with uncoated PDC and rollercone bits, but as the ROP dropped down to only 10fph it was decided to try something new. The PDC bit chosen to be coated had previously been the top ROP performer in other Tembungo wells so the risk was considered minimal. It was also considered unlikely that the bit coating could affect the performance in a negative manner.

The results achieved were impressive. The bit was run in hole at a depth of 10.125ft and reached TD at 11.527ft with an average ROP of 72.3fph. This was a double in ROP compared to the previously used uncoated bits. It was also noted that the flow rate and WOB was lower when using the coated bit. The coated bit prevented balling when using mud weights of up to 1.27sg. They concluded that good bit hydraulic design in combination with coating of the bit surface was key factors to prevent the shale from attaching and balling up.

Comparing the results achieved with the coated bit and an electrically charged steel bodied bit showed that the coated bit performed 50% better. The electrically charged bit reached an average ROP of 51fph while the coated bit reached as earlier mentioned 72.3fph.

At the end of the 12-1/4" run the surface treatment of the bit had completely worn off. The toughness of the coating has been improved after the Tembungo B9 well was finished, but it will always be a problem that has to be considered when planning to use flouropolymer coatings. Especially if there is a large risk of encountering abrasive stringers, since the coating will erode off much faster. The operator has to decide if the possible savings outweighs the cost of the coating. As of the time of writing this thesis the use of the flouropolymer coating is not common and not used at all by Halliburton DBS on their bits.

4.3. Electro-Osmosis

When drilling in high pressure reactive shale formations using a PDC bit and water based mud the cuttings can easily swell and ball up on the bits surface. As mentioned in earlier chapters the cuttings are forced onto the bit because of the low permeability of the drilled formation and high pressure in the wellbore. If the cuttings come in contact with an electric field the water inside it will start to migrate towards the cathode object and create a thin film separating the shale cutting from the object. The process that occurs when this happens is called electro-osmosis, and it hinders the shale from sticking to the bit surface thus preventing bit balling from occurring.

The paper by Cooper[10] from 1994 will be the source of this theory. To provide evidence for the improvements obtained by electro-osmosis they have performed tests in a medium sized simulator. Pierre and Wellington are the selected shale formations that were drilled during the test by using a rollercone bit with a size of 2.5” diameter and a PDC bit with a size of 4” in diameter.

Four known phenomena occur when putting a charged entity in a fluid system; electro-osmosis, the streaming potential, electrophoresis, and the sedimentary potential. Out of the four, the two phenomena mentioned first are considered complimentary. This is because the definition of electro-osmosis is the movement of a charged species through a permeable medium subject to an electric field, while the streaming potential describes the generation of an electric field as a charged fluid moves through the medium.

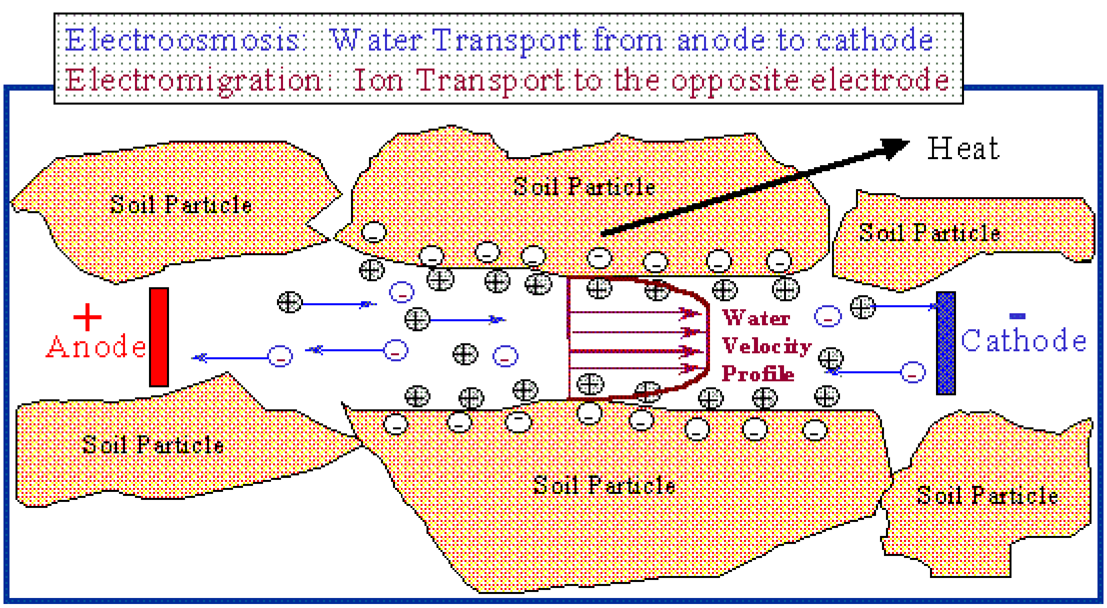


Figure 28 Water transport from anode to cathode. (Source: www.terrancorp.com)

To understand why the water moves out of the shale when it is in the vicinity of an electric source, one has to know what type of elements is in the shale itself. Positive ions like Ca_{2+}, K_{+}, Na_{+}, and Mg_{2+} are loosely intercalated within negatively charged silicate sheets that persist in the shale. These cations will start to move towards any cathode nearby and at the same time drag the water containing these cations with them. By applying direct electrical potential to a drill bit that comes into contact with shale, the water will be forced to move out of the shale and create a thin film on the outside surface. Figure 28 is a rough drawing of how the water is transported from the anode towards the cathode.

Figure 29 shows a schematic of the machine used to do the simulations. It has the ability to ensure a preferred constant load while drilling with a maximum WOB of 178kN. All the measurements were done using a tachometer (rotary speed), and a Linear Variable Differential Transducer (displacement). These can all be seen in the figure.

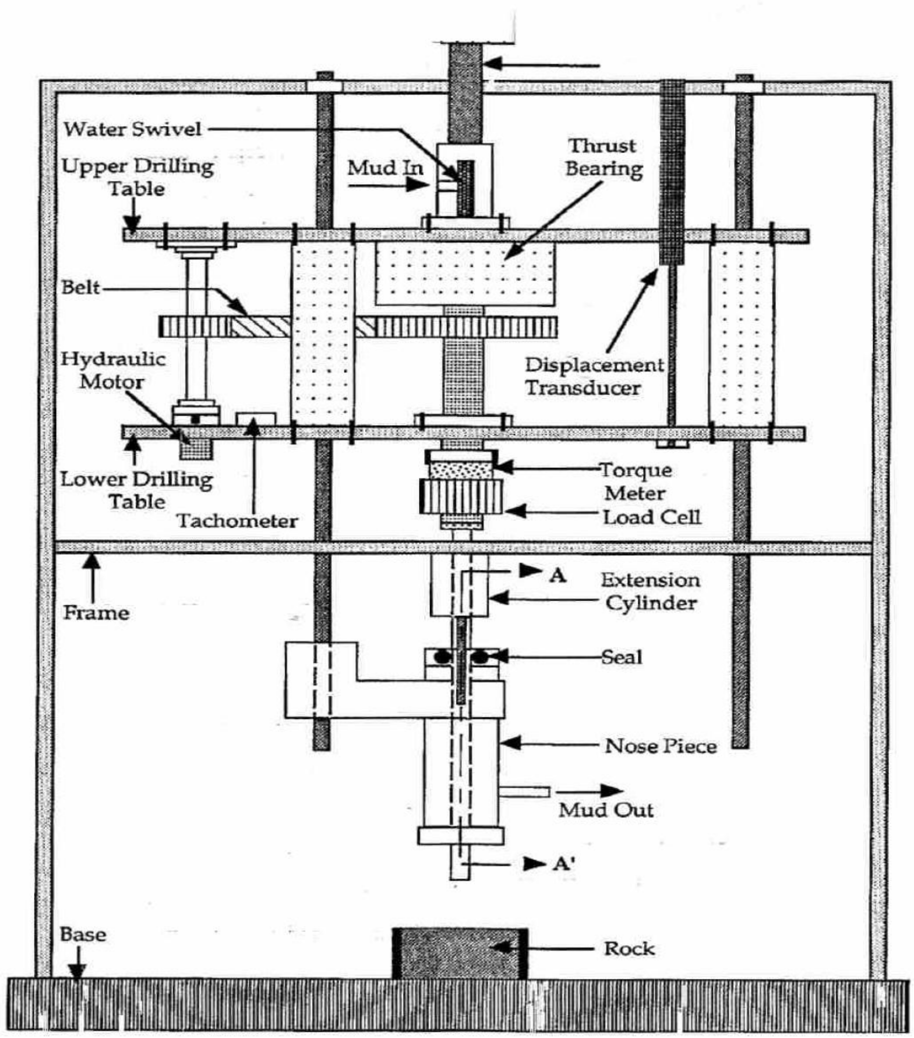
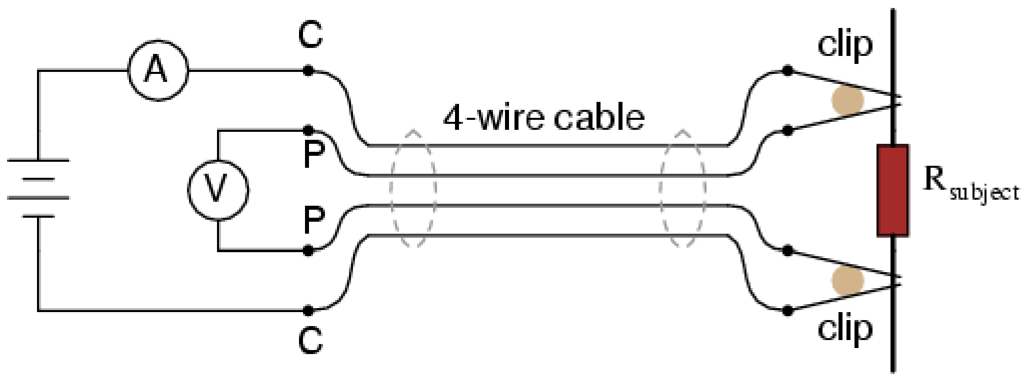


Figure 29 A rough schematic of the machine used for the experiments (Source: Cooper[10])

To get comparable results the bits used to drill were both held neutral and as a cathode. By insulating the formation sample at the bottom and putting a positively charged wired mesh around it, an electrical potential between the rock and bit could be obtained. The bit would then act as grounding for the electric current. A 10 volt potential, generating an electric current between 0.5A and 1.5A, was applied during the experiment with a negative bit and kept constant. The electric current had to be measured accurately, so a four-wire measurement technique called Kelvin had to be utilized. This technique is mainly used to determine the electric resistivity of a subject, but if the resistance is known to be 1ohm as it is in this case, it can also be used to measure the electric current. A general drawing of the measurement setup can be seen in Figure 30. The clips shown in the figure are known as Kelvin clips.



$$R_{subject} = \frac{\text{Voltmeter indication}}{\text{Ammeter indication}}$$

Figure 30 The 4-wired Kelvin measuring method (Source: www.allaboutcircuits.com)

Several types of procedures were tried out during the experimentations. The WOB would be kept constant for the entire test and then the bit would be pulled and tried at another spot in the sample, or the WOB would be changed several times during a single test. They also tested the efficiency of electro-osmosis by only applying the electric potential as soon as drillbit balling was thought to be occurring. This would give a good indication as to the cleaning properties of the experiment. The last variation of testing was to drill with constantly applied electric current to determine if it would be more effective to have a constant electric potential or if it was sufficient to only apply it when balling was thought to be occurring.

Results achieved with constant applied WOB are shown in Figure 32 and Figure 31. Figure 32 shows the ROP as a function of WOB after testing the 2.5” rollercone bit, while Figure 31 shows ROP as a function of WOB after testing the 4” PDC bit. From the rollercone bit results one can see that the effect of the electro-osmosis is greater the higher the WOB, however for low WOB there are no improvements at all. It is believed that this is not due to inefficiency of the negative potential but rather due to the generation of cuttings being small enough for the system to get rid of. When the WOB reaches a certain magnitude the bit starts to ball up, and that is when the graph starts to separate in favor of the negative potential bit.

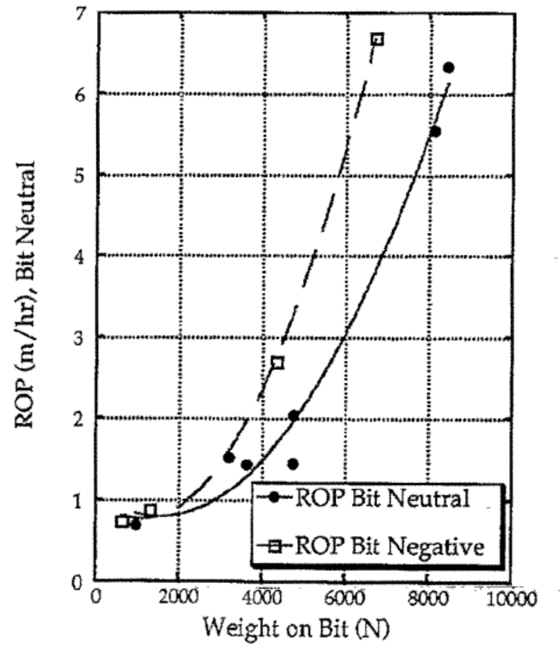


Figure 31 Rate of Penetration as a Function of Weight on Bit – PDC Bit (Source: Cooper[10])

The graph for the PDC bit shows a different curve, but also here one can see that the effect on the ROP is greater with higher WOB. Since a PDC bit is more susceptible to balling the improvement is visible at much lower WOB compared to the rollercone bit. At 6000N WOB the obtained ROP is almost doubled with the negative potential bit from 3m/hr up to 5.5 m/hr. The ROP reached with the negative potential bit is not very high, but it is still an improvement that would be very much valued in the field. Since this is a small scale test the effect could potentially be greater in full size well operations.

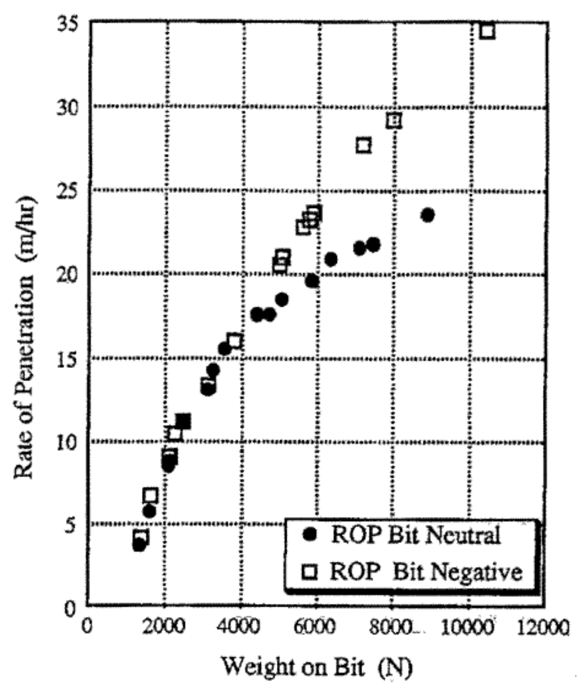


Figure 32 Rate of Penetration as a Function of Weight on Bit – Rollercone Bit (Source: Cooper[10])

The previous tests were all done with the use of fresh water as drilling mud, but after that a similar test was performed with a water based mud containing bentonite, revdust, drispac and NaCl. In the paper the mud is referred to as Mud A. For this test only the 4” PDC bit was used. Results achieved here are presented in Figure 33 as a bar chart. The bars are put together two and two, were the left bar shows the initial ROP while the right

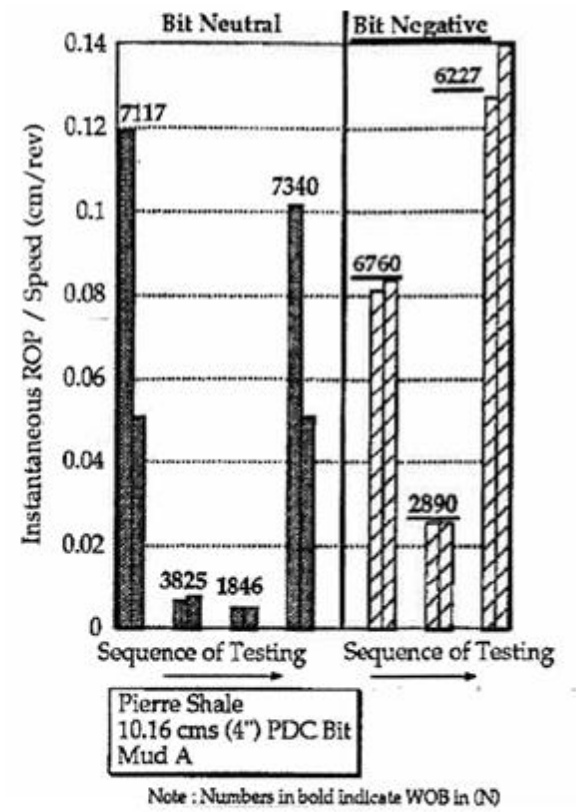


Figure 33 ROP for different WOB and Bit Polarity - Bit Cleaned (Source: Cooper[10])

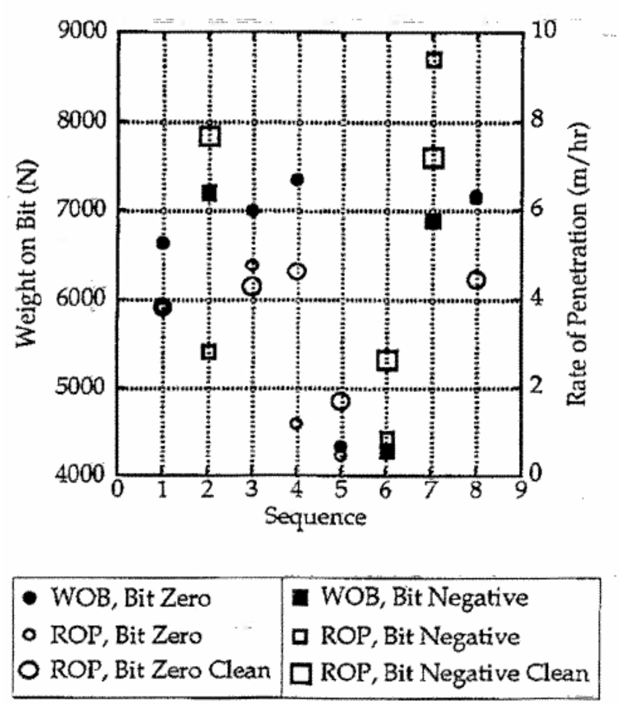


Figure 34 ROP for different WOB and Bit Polarity - Bit Not Cleaned (Source: Cooper[10])

bare shows the ROP at the end of the experiment. The graph is also divided with the uncharged bit on the left and the charged bit on the right. For the uncharged bit the ROP drops below half the initial rate when using high WOB. Using low WOB the ROP does not change at all due to the absence of bit balling. For the charged bit, showed to the right in the graph, the ROP at the end of the run is either equal to, or higher, than the initial ROP.

The last experiments were done by switching of the potential of the bit during drilling to test if a balled up bit could be cleaned by turning the potential on again. Figure 34 shows the results obtained from the tests using this method. The graph shows every result in sequential order where the bit without potential activated is shown as circles, while the bit with potential activated is shown as squares. Moving on the graph from left to right one can see that the WOB is kept somewhat steady, and that the ROP suddenly drops severely most likely due to the occurrence of bit balling. Once the WOB is decreased and the potential is turned on the ROP starts to increase again, indicating a clean bit.

The observations from these tests implicate that there is no need to put a continuous potential to the bit, and that it is only necessary to switch it on to un-ball the bit.

To recap what has already been mentioned in this section about the use of electro-osmosis to prevent bit balling, the effect was much greater while using the PDC bit compared to the rollercone bit, the rollercone bit with activated potential performs better with higher WOB as it penetrates deeper into the rock, and it is possible to “un-ball” a bit using electro-osmosis while drilling by just lowering the WOB.

If this type of technology has been used with good results by the industry itself in live well situations is unsure since there doesn’t exist any cases on record available. The major issue is if it has the ability to “un-ball” a bit in severe cases were all other methods have failed. A “lighter” version of this technology has been put to use were the bit is electrically charged before it is put down hole, but the charge “wears” off and it is not very effective in severe bit balling cases.

4.4. Bit Design

A lot of research has gone into the development of a new PDC bit designed specifically for plastic shale environments. The paper written by Graham Mensa-Wilmot et al.[13] discusses this innovative technology and is used as the main source for this chapter. They characterize the problematic formation as an NPF environment. This means that it`s initially an environment PDC bits should perform very good in, but due to the great depth and use of WBM the ROP drops way below the expected drilling rate.

The focus of the bit design research has been on the hydraulic efficiency and cutter design. Hydraulic efficiency governs the bits ability to remove cuttings from the bit head and push it out into annulus. Several factors governs the hydraulic efficiency of a bit; number of nozzles, position of nozzles, type of nozzles, number of blades, and size of flow area. When it comes to the nozzles the position is the most critical. If the position is optimal, then the amount of nozzles can be limited and the type of nozzle used can be changed whenever needed. The size of the JSA is dependent on three different factors; size of the bit, amount of blades, and size of the blades. Having a larger bit with few blades that are both thin and deep gives a large JSA. The type of material used for the body can actually limit the JSA as well. A matrix body can handle more abrasive formations, but is more brittle and the depth of the blades is therefore limited. With a steel body the bit can handle less abrasive formations, but the blades can be significantly deeper and the body surface is much smoother.

The Graham Mensa-Wilmot et al.[13] paper explains the low ROP in deep shale formations to be caused by bit balling. Cuttings removed from the formation are described as ribbon like in form, see Figure 35, and it is these ribbons that attach to the bit and inhibit proper cutting of new formation. As mentioned earlier there is no proof of this bit balling when the bit is POOH since the cuttings is believed to detach itself from the bit during tripping out of hole.

Figure 35 Ribbon shaped cuttings (source: Graham Mensa-Wilmot[13])

To avoid the creation ribbon shaped cuttings, or at least limit their size, it is believed that the bit needs to “scoop” the formation instead of cutting it in the regular way. The best way to create a bit with a “scooping” action while drilling is to redesign its cutters. For a normal PDC bit the cutters cutting surface is straight and positioned in a negative back rake angle. This new design for the cutters is a big part of the new innovative technology mentioned by the paper and Figure 36 on the next page shows how the new design looks like. With the new design the attack angle is now defined as a positive back rake angle. Figure 37 shows a normal type of PDC cutter. The main difference is of course the angle of the cutting surface. This angle ensures that the cutters get pushed into the formation at a specific approach angle, and the formation is thereby “scooped” up. It is considered the most effective way to cut deep shale formation that is exposed to high mud weights.

Figure 36 New cutter design (Source: Graham Mensa-Wilmot[13])

Figure 37 Standard cutter design (Source: Graham Mensa-Wilmot[13])

From Figure 36 an extra angle at the tip of the cutter can also be seen. This is created to strengthen the cutter since the tip of it would otherwise be very much exposed and likely to become chipped off if hard stringer would be encountered.

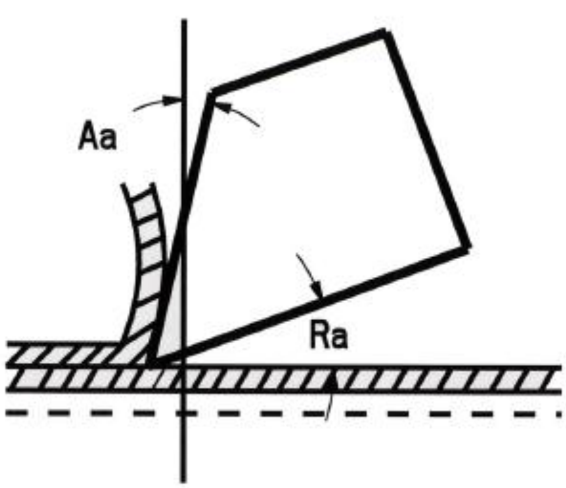


Figure 38 Cutting action of a cutter with positive backrake (Source: Graham Mensa-Wilmot[13])

Figure 38 shows the cutting action of the new positive back rake cutter where Aa is the attack angle and Ra is the relieve angle. The relieve angle ensure minimal substrate contact with the formation while drilling, and thereby reducing the carbide drag. Carbide drag being the friction occurring when the cutters backside comes in contact with the formation. To reduce the carbide drag even further another new design for the cutter was introduced. The new design can be seen in Figure 39 where it is compared with the previous cutter design. However, it does not show the ground tip on the new design, but it is present on cutters eventually used for drilling.

In practice the positive back rake angle cutters create an additional void space in front of them where the ribbon like cuttings can dilate and extend. The shortening of the cuttings happens in this open space, and thereby become easier to force out of the bits cutting area and into annulus.

Figure 39 The new cutter design (left) compared to the revised edition (right) (Source: Graham Mensa-Wilmot[13])

Careful analysis of the relationship between ROP, Aa, Ra, and lithology has led to the geometrical design behind the new cutter element. What has been discovered, however, is that even though the cutter might be ideal for drilling shale formations, other lithologies such as limestone and sandstone are drilled better with the normal flat cutter. Different types of geometries have therefore been designed so that it`s possible to design the bit for the expected lithologies, and improve the bits performance in these lithologies without sacrificing the shale-drilling efficiency.

A test bit was used in several laboratory tests to determine the performance of the bit and its design. Two types of water based drilling fluids were used, only referred to as version S and version M, with version M being the fluid with better shale inhibition and wellbore stabilization characteristics. In addition to testing with different mud types, a test was also performed with varying RPM and WOB values to determine the optimal combination of the two.

The two tests with different types of drilling fluids used a set mud weight of 1.92sg, 10klbs WOB, and 75 RPM. These values were selected because they are considered the worst operational conditions, and should therefore give a good indication of how well the bit can perform. With the version S WBM used in the test the bit drilled with an average ROP of 4.72m/hr through a Pierre Shale formation, whilst with the version M WBM it managed to drill in the exact same type of formation with an average ROP of 6.71m/hr. Considering the given values of mud weight, WOB and RPM these are both decent results.

The results for the third test with the varying parameters are presented in the Figure 40. Version M WBM with a weight of 1.44sg was used for the test, and again the same formation type as before was drilled through. With the lowest ROP at 2.13m/hr and the highest at 24.7m/hr, more than ten times faster. Bit balling was initiated with the highest ROP, and the resulting ROP for the lower RPM afterwards was therefore significantly lower. The test clearly indicates that a high RPM and low WOB is essential to optimize the new bits performance when drilling in shale formations.

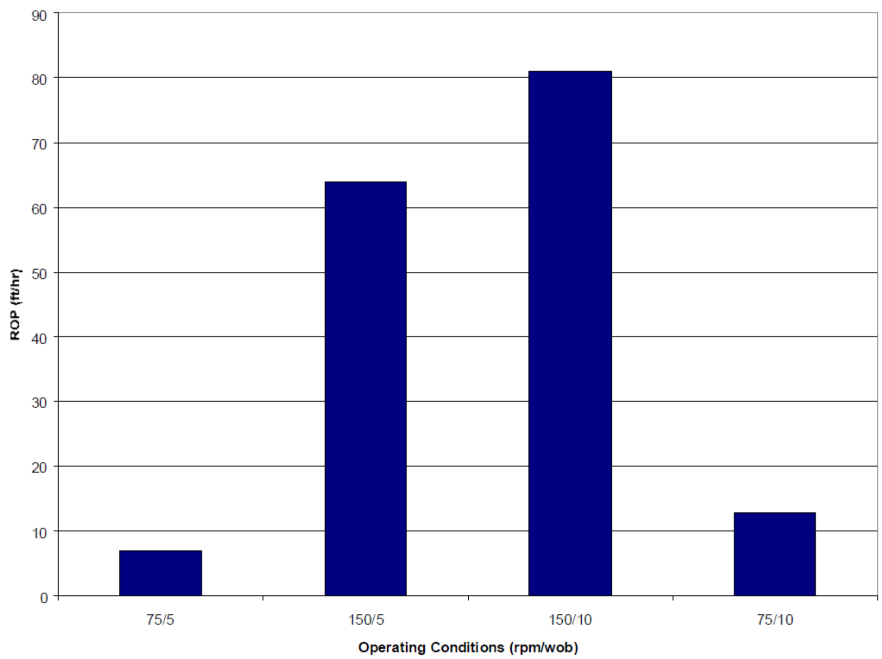


Figure 40 ROP versus Operating Conditions for the newly designed PDC bit (Source: Graham Mensa-Wilmot[13])

In the laboratory tests a 6-1/2" bit was used, but to perform field tests a bigger 8-1/2" had to be designed. Figure 41 shows the new 8-1/2" bit specifically designed for drilling in deep shale formations. Only two field cases are presented in the paper by Graham Mensa-Wilmot et al[13], but several runs in other wells has also been recorded with this type of bit. The two field cases presented are both from the South Texas area. The first case was a well with two offset wells only referred to as "well J" and "well K". The new bit managed to drill with the highest ROP, 5m/hr vs. 3.75m/hr, and footage, 605m vs. 595m, compared to both these wells, and it also confirmed that the conditions concluded as optimal in the lab tests applies for the real field cases. The number of bits used to drill the 8-1/2" section in the well using the new bit was only 2, compared to 3 and 5 in the other two wells.

Figure 41 The new commercialized PDC bit with positive backrake cutters (Source: Graham Mensa-Wilmot[13])

In the second case the new PDC bit managed to drill only slightly faster than the fastest rollercone bit in an offset well, 8.9m/hr vs. 8.53m/hr. However, the PDC bit drilled 25% longer than the best rollercone which in turn drilled with a much lower ROP, 6.6m/hr.

The results seen are not dramatic improvements, but they do show improvements that are large enough to be seriously considered for future deep shale drilling applications. However, even though the bit in Figure 41 is commercialized it has not been extensively used by the industry and further development is still ongoing.

4.5. Water Based Mud with Silicates

The bit is not the only part of a drilling system that is considered possible to improve for deep shale drilling. There has been a lot of experimentation with different environmentally friendly and relatively cheap additives to develop the best possible drilling mud for plastic shale applications. One type of additive that has shown impressive qualities is silicates, mainly sodium (Na_2SiO_3) and potassium (K_2SiO_3) silicates. By fusing either soda ash (Na_2CO_3) or potash (K_2CO_3) with silica (SiO_2) sand it is possible to create the silicate additive.

The use of silicates in drilling mud to control reactive shale formations were first introduced in the 1930s by Garrison, Baker and Vietti. They used high concentrations of the soluble silicates in drilling mud for over 100 wells in the Gulf Coast Area. However, at the time it was very difficult to control these fluids because they had such a high rheology. It was therefore replaced by a lime-quebracho mud instead in the 1940s. Quebracho is a naturally occurring acid found in several different plants and plant parts. The lime-quebracho was thought to provide adequate shale control while providing a fluid with a much easier controlled rheology.

It was later discovered, in the late 1960s, by Darley that most shales could be sufficiently controlled with more dilute solutions of sodium- and potassium silicates, and the shale control attributes could be even more effective by adding simple salts (e.g. KCl, K_2CO_3, NaCl) or non-ionic solutes (e.g. glycerol, ethylene, glycol). The use of silicates in drilling mud was therefore re-introduced. However, despite having three successful trials where the silicate mud showed its superior wellbore-stabilizing properties the industry was still very much reluctant to take it into full use.

30 years later, in the 1990s, the silicate based mud was yet again introduced. This time several factors had been improved and new additives to better control the mud had become available. The causes of the problematic rheology control were now better understood, and the new and compatible high performance polymer-based rheology modifiers and fluid loss agents had become available. In addition

Table 2 Pierre 1E shale (Source: R. Schlemmer[15])

Quartz	34%
Feldspar	6%
Calcite	1%
Dolomite	5%
Siderite	—
Pyrite	2%
Kaolinite	6%
Illite/Mica	18%
Chlorite	—
Smectite and mixed layer	28%
CEC (meq/100 g)	22
Porosity	17%
Permeability, horizontal (D)	$\sim 1 \times 10^{-6}$
Permeability, vertical (D)	$\sim 1 \times 10^{-7} - 10^{-8}$

solids removal equipment was now a lot more effective, and there was a better understanding in the industry of the wellbore stability problems in general.

Several experiments have been performed with silicates to learn how it reacts with shale, and how well it performs with regards to drilling performance. One particular property of the silicate mud is the creation of an osmotic membrane. In the paper by R. Schlemmer et.al.[15] several tests have been performed on a Pierre 1E type shale, Table 2, to determine the efficiency of this membrane. Three different types of membranes are defined in the paper. The first, Type 1, is characterized by coupled flows of water and solutes between fluid and shale. The second, Type 2, is defined as a membrane that greatly reduces the near-wellbore permeability of shale and restricts the flow of both water and solutes. The last, Type 3, membrane transport water more selectively, but shale permeability and fluid chemistry may alter performance measurements. Invert emulsion fluids, or Oil Based Muds, creates a membrane of Type 3, whilst the Water Based Muds with Silicates creates a membrane of Type 2. Table 2 shows how these membranes are categorized based on the interaction between drilling fluids and shale.

Table 3 Behavior of the three types of membranes (Source: R. Schlemmer[15])

Membrane	Type 1	Type 2	Type 3
Position	Internal	Primarily External	Primarily External
Character	Dynamic, not permanent	Static fixed durable	Dynamic, not permanent
Double layer effects	Dependent	Independent	Independent
Clay/shale effects	Dependent	Independent	Independent
Typical reflection coefficient (σ)	<0.2	>0.5	1.0
Osmotic pressure	To 1,000 psi 6.9 MPa	To 4,000 psi 27.6 MPa	Variable

After thorough testing it was concluded that the fluids creating a Type 2 membrane was almost as efficient as the invert emulsion fluids Type 3 membrane. Type 2 membranes had an efficiency rate of more than 0.5, whilst Type 3 always had an efficiency rate of 1. The Type 1 membrane only managed to reach a maximum of 0.2. Experiments with different types of salts in the WBM was also performed, and as Table 4 shows a lower concentration of CaCl2, with a higher activity level, was found to be the most efficient.

Table 4 Results achieved with WBM A versus WBM B (Source: R. Schlemmer[15])

	WBM A	WBM B
Wellbore pressure	900	900
Linear trend	$y = 1.31x+484$	$y = 0.78x+525$
Salt	NaCl	$CaCl_2$
Concentration	20%	10%
Activity	0.82	0.94
Maximum osmotic pressure	416	375
Membrane efficiency	11%	31%
Slope	1.31	0.78

The silicate-based drilling fluid has proven to be almost as efficient as the OBM in laboratory tests, but it has to be put to the test in real well cases as well. That has been the case on several wells all the way back to the 1930s, but the behavior of a silicate-based drilling fluid is quite complex. It has not been an easy task to determine how the fluid will react in different environments and how one should act if the properties of the fluid start to deteriorate. Several papers present real well cases where the silicate mud system has been put to use. Even though there are difficult challenges that have to be overcome, the common factor for them all is that they all have had a positive experience with the use of the silicate-based mud.

The paper written by Tomislav Soric et al.[24] on the subject silicate based drilling fluids discuss experience gained from 6 different wells. Since the paper was written in 2004 it is very much up to date with the newest research and development with the use of sodium silicate. The sodium silicate WBM performed well, but since the behavior of the fluid is quite complex several lessons were learned. Silicate concentration depletes when in contact with certain minerals. It is therefore very important to closely monitor the silicate concentration at all times since that is what governs the fluids inhibitive effectiveness. It wasn't always possible to measure this concentration, so it was discovered that pH levels and alkalinities trends were good indicators. If the concentration drops the fluid has to be treated.

Anhydrite and salt in the drilled formation can contaminate the fluid, and the proper reaction to this is to add caustic soda. By constantly monitoring the fluids properties and adding caustic soda whenever needed it is possible to keep the fluid very stable. It was also discovered that adding caustic soda would help control rheology and reduce polymerization of the silicate. The opposite reactions occur if too much caustic soda is added, and flocculation of the polymers and an increase in viscosity will be the following result. Potassium hydroxide is an alternative to the caustic soda that could be used for the same purpose.

The paper mentions several times how important it is to keep the pH level of the WBM at 11 or higher. If the pH level drops below this, the effective shale inhibition will drop with it. Between 11 and 12.5 is considered optimal, and by adding caustic soda the pH level can easily be maintained. Only small additions of caustic soda each day is required.

As mentioned before the paper discusses 6 wells that were drilled with the sodium silicate WBM. According to the paper the drilling fluid systems worked well, but no exact performance in m/hr is mentioned. No comparison of performance to offset wells are mentioned either. However, one very good example of how effective the sodium silicate WBM can be is one of the offset wells for the Zidane well. The details of the Zidane well and its offset wells will be further discussed later in this thesis. With the sodium silicate WBM an average ROP of 41m/hr in the 12-1/4” section, almost 30m/hr more than what was achieved in the Zidane well at its best in the same section. At the end of the 12-1/4” section the ROP had dropped down to 20m/hr, but that was still more than 15m/hr faster than in the Zidane well at the same depth.

Due to some negative experience with borehole stability during drilling operations with silicate WBM systems, Halliburtons drill fluid department Baroid decided not to continue work with this type of drilling fluid. However, the improvement in ROP in the same area and through the same type of formations as Zidane should open for the possibility of future use of this drilling fluid system.

5. Well Analysis

The following chapters will contain a detailed analysis of the actual operational data for one of the most recent wells that experienced low ROP in deep shale formations. In addition, the same detailed analysis will be performed for its offset wells, wells from a nearby producing field, and finally a well drilled by the same operator not long after. The purpose will be to attempt to discover trends that stand out and show indications of a possible solution to the low ROP problem.

5.1. The Zidane Well

The 6507/7-14 S Zidane exploration well drilling process started at the 14th of June 2010, and lasted for as long as 65 days. It was drilled from the Bredford Dolphin semi-submersible drilling rig, and reached a total depth of 4477m true vertical depth (TVD) on August the 17th.

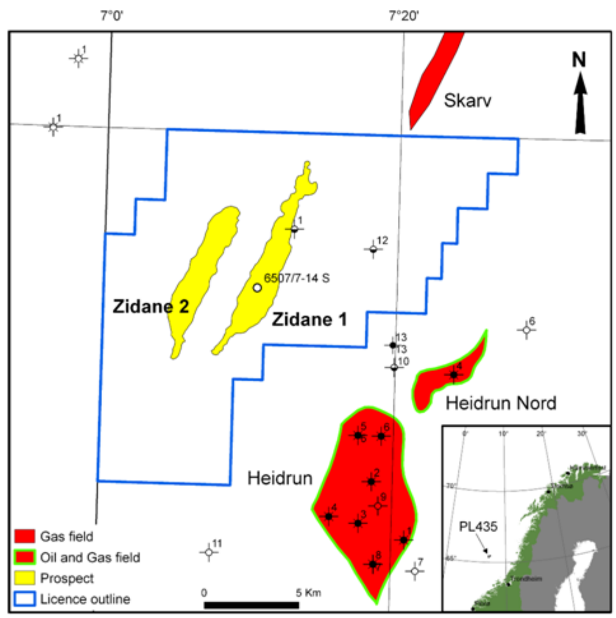


Figure 42 Location of the 6507/7-14 S Zidane well (Source: Final Drilling Programme[9])

As mentioned above, the Zidane well is the most recent well where low ROP/ plastic shale formations have been a considerable problem. Even though the exact cause of the low ROP problem is unknown, what is clear is that the problem is related to the use of WBM. Once the drilling fluid in the well was displaced from WBM to OBM the low ROP was no longer an issue, and TD could be reached with a much more decent speed.

Figure 42 shows the location of the Zidane well in the Norwegian Sea, just southwest of Skarv, and northwest of Heidrun. Three wells by ConocoPhillips were used as offset wells for Zidane as they had drilled through much of the same formation layers and all of them had been drilled with WBM. The pore pressure prognosis showed later in this case study had also been mostly based on the actual pore pressure from these wells. In the following chapters the information presented has been gathered from Halliburton DBS[3] and Sperry Drilling[8] departments. Halliburton DBS bit database has also been frequently used as a source.

5.1.1. Bit Record

No significant problems occurred in the top-hole sections, and the casing shoe for the 17-1/2" section was set at 2192.7m MD.

Figure 43 The FXG65R with 3 balled up waterways (Source: EOW report Zidane[3])

Next was the 12-1/4" section which was to be drilled from the 17-1/2" casing shoe down to a planned depth of 3882.9m TVD. Since the section was planned drilled with water based mud, and reactive shale formations were expected, the well was displaced to Baroids Performadril mud with a weight of 1.55 sg. The section started at a depth of 2192m MD, in the Springar Formation, and the first 200 meters were drilled with decent performance. However, when a depth of 2412m MD was reached the ROP dropped down to 5-6 m/hr. The bit used at the time was the FXG65R, an aggressive PDC bit with a matrix body and extended gauge designed for directional drilling. A weight on bit between 20-30 tons was applied to try and increase the drilling performance, but it had little to no effect. Due to the poor ROP the bit was therefore pulled out of hole (POOH) in the Nise formation at 2471m TVD. A visual inspection of the bit at surface showed that 3 out of 6 waterways where balled up with very hard and densely packed drilled formation. Figure 43 show a top view of the bit with the three balled up waterways.

Figure 44 The FSFX653ZR anti balling bit (Source: EOW report Zidane[3])

A new bit called FSFX653ZR was then put into the hole, Figure 44. The FSFX653ZR is a 6 bladed steel bodied bit with 9 nozzles to prevent plugged waterways. This is also a long gauged bit designed for rotary steerable systems, in this case the GeoPilot®. The performance achieved with this bit was even worse, so after having drilled from 2471m MD down to 2592m MD, still in the Nise formation, with an average ROP of 2-5 m/hr it was POOH. Before pulling the bit however, at a depth of

2488m MD, a 10m3 1.55 sg Glycol/LCM pill was pumped down to the bit. The bit had been pulled off bottom and the pill was used to clean the bit in case of balling. This did not have any positive effects on the performance when drilling resumed. The bit was dull graded 1/1/NO/A/X/I/BU/PR, which means very little worn.

Even though the bit had 9 nozzles, there was still one water way slightly plugged. No other signs of balling or wear on the cutters were found, and the slightly plugged water way did most likely not affect the performance of the bit. It is however an indication that the bit might have been balled up while drilling, and that most of the balled up material might have dropped off during tripping.

Figure 45 The EQH1GRC milled tooth rollercone bit (Source: EOW Report Zidane[3])

Since the PDC bits couldn't perform well in the shale formation environment, it was decided to use a mill tooth roller cone bit instead, the EQH1GRC. Figure 45 shows the actual bit after it had been run in hole. This is not an uncommon practice when experiencing low ROP in plastic shale formations and the ROP did increase to an average of 6.35 m/hr. The problem with a rollercone bit however, is the lifetime expectancy of the cone bearings. After 49hrs and 269 meters of drilling, down to 2861m MD in the Nise formation, the bit had to be POOH due to the bearings reaching its limits. It was dull graded 2/2/WT/A/E/I/NO/Hr and was scrapped. Even though the performance of the bit was not a dramatic improvement, it was still decided that the best thing to do was to run another mill tooth bit and try to get through the Shetland Group formations.

The new mill tooth bit had an initial ROP of 3.5 m/hr, but later increased to 6.8 m/hr. It drilled from 2861m MD through the Shetland Group and into the Cromer Knoll Group and reached a depth of 3059m MD before it too had to be pulled due to the lifetime expectancy of the bearings. It was dull graded exactly the same as the previous mill tooth bit and had to be scrapped. The overbalance of the mud was calculated at this point to be 44bar without riser.

It was then decided to again run with a PDC bit, this time the FXG75. The FXG75 is 7 bladed, matrix bodied bit with 7 nozzles designed for drilling tough formations. Because of the 7 blades the JSA has been significantly reduced and there is a much higher risk of balling, and the bit is therefore not recommended for drilling in sticky shale formations. The bit was POOH in the Lange formation at 3180m MD with only 2.5 m/hr average ROP. Some spikes in ROP were experienced however when glycol pills with Baracarb were pumped during drilling. As the pill traveled through the bit and into annulus the ROP reached a maximum of 24.5 m/hr. A reduction in stand pipe pressure was also observed while pumping the pills. The bit came out green, 1/1/PN/A/X/I/NO/BHA, with no blocked water ways or wear on the cutters.

Next in line was a Baker Hughes PDC bit on a motor, the HCM605Z. Again, no improvements in performance compared to earlier used PDC bits. The bit drilled from 3180m MD down to 3233m MD, still in the Lange formation, with an average ROP of 1.85 m/hr. At this point the overbalance without riser was calculated to be 51bar with the 1.55sg Performadril drilling mud in hole. The bit was pulled due to the low ROP and was dull graded 1/1/WT/A/X/I/NO/PR.

Another mill tooth rollercone bit was run in hole as a last attempt at getting a decent performance through the rest of the 12-1/4" section. This time hard stringers were encountered so the bit had to be pulled after only 56m of drilling, at a measured depth of 3289m. Due to the hard stringers the bit had to be scrapped, and was dull graded 2/2/WT/A/F/I/NO/HR. With approximately 650m left to TD of the section it was decided that the best solution would be to switch from water based mud into oil based mud. The well was displaced from the 1.55sg WBM over to a 1.65sg OBM, and a new FXG75 PDC bit was run in hole. The bit reached an ROP of 35m/hr, but was eventually controlled to a much lower ROP of 11.4 m/hr because of logging requirements. This is an immediate and dramatic increase in ROP just from changing from WBM to OBM. A result like this was not unexpected, but it is important to notice that the same type of bit that earlier only managed to get an average ROP of 2.5m/hr now managed to drill up to 35 m/hr in the same type of shale formation.

The section was drilled to TD at 3902m MD in the Melke formation with the FXG75 bit, and no damage to the bit was observed when POOH. After three weeks and a total of 8 bit runs the 12-1/4" section was completed.

The 8-1/2" section was drilled successfully using an FXG75R PDC bit and OBM. ROP was intentionally kept at a low rate due to requirements from logging data and the search for a good coring point. The bit was used to drill the entire section from 3948m MD down to TD of 4534m MD.

5.1.2. Bottom Hole Assembly


Figure 46 PDM with two different bit subs (Source: Halliburton.com)

For the most part of the 12-1/4” section Sperry Drilling Geo-Pilot was used in combination with several MWD tools, a Megaton Jar, Drill collars and heavy weight drill pipes (HWDP). None of the tools had a greater outer diameter than 8-1/4”, except for the Geo-Pilot which had an outer diameter of 9-5/8” to be able to reach the borehole wall. There were no signs of balling on the BHA when pulled, and the pressure drop over the tools used was not more than expected.

At a depth of 3180m MD the Geo-Pilot was changed with a drilling motor from Sperry, Figure 46. This was done to be able to increase the RPM on the bit and hopefully improve the ROP. The motor worked as intended, but the ROP was at an all time low of 1.7 m/hr. After only 53m of drilling, at a depth of 3233m MD, the BHA was POOH and redone with the Geo-Pilot again. The BHA was put back in the hole with a new mill tooth bit and drilled to a depth of 3289m MD with an average ROP of 2.34m/hr. As mentioned earlier, the mud was at this point displaced to the OBM and an immediate increase in ROP was seen.

5.1.3. Mud and Hydraulics

The mud weight and rheology was kept constant almost through the entire 12-1/4” section. A Performadril WBM drilling mud with additives: Barite, KCl, Soda Ash, Pac-L, Brinedril, Gem GP, N-Dril HT+, Drill Water, Baracarb 5/50/150, Steelseal and Performatrol. The potassium chlorite, glycol (Gem GP) and Performatrol are additives specifically used to prevent unwanted reactions between the drilling mud and the shale. Because of the slow ROP the drilling fluid had been in contact with much of the shale formations for almost 3 weeks and some instability with cavings was experienced. The cavings together with the slow ROP are the main reasons why they eventually chose to change over to OBM. However, keeping the well stable for almost 3 weeks is a very good achievement and a good indication that the inhibitive attributes of the drilling fluid worked as intended.

To try and increase performance of the bits in the 12-1/4" section several glycol pills were pumped to clean the bit in case of balling. 1 pill was pumped at the second bit run, and 2 pills were pumped during the fifth bit run. All of the pills had positive effects on the ROP, but as soon as the pill had past the bit and gone into the annulus the performance dropped again. This quite possibly has to do with the fact that the pills had a much lower viscosity than the drilling mud itself, and that way they got a more turbulent flow around the bit. The glycol pills also contained Baracarb, an inert additive that is used to erode whatever material that might have attached itself to the bit. Baracarb does not affect the fluids viscosity.

Figure 47 shows the prognosed pore and fracture pressure as well as the planned mud weight for the entire well. As mentioned earlier the weight was kept stable at 1.55s.g through most of the 12-1/4" section, until it was increased to 1.65s.g and changed to OBM.

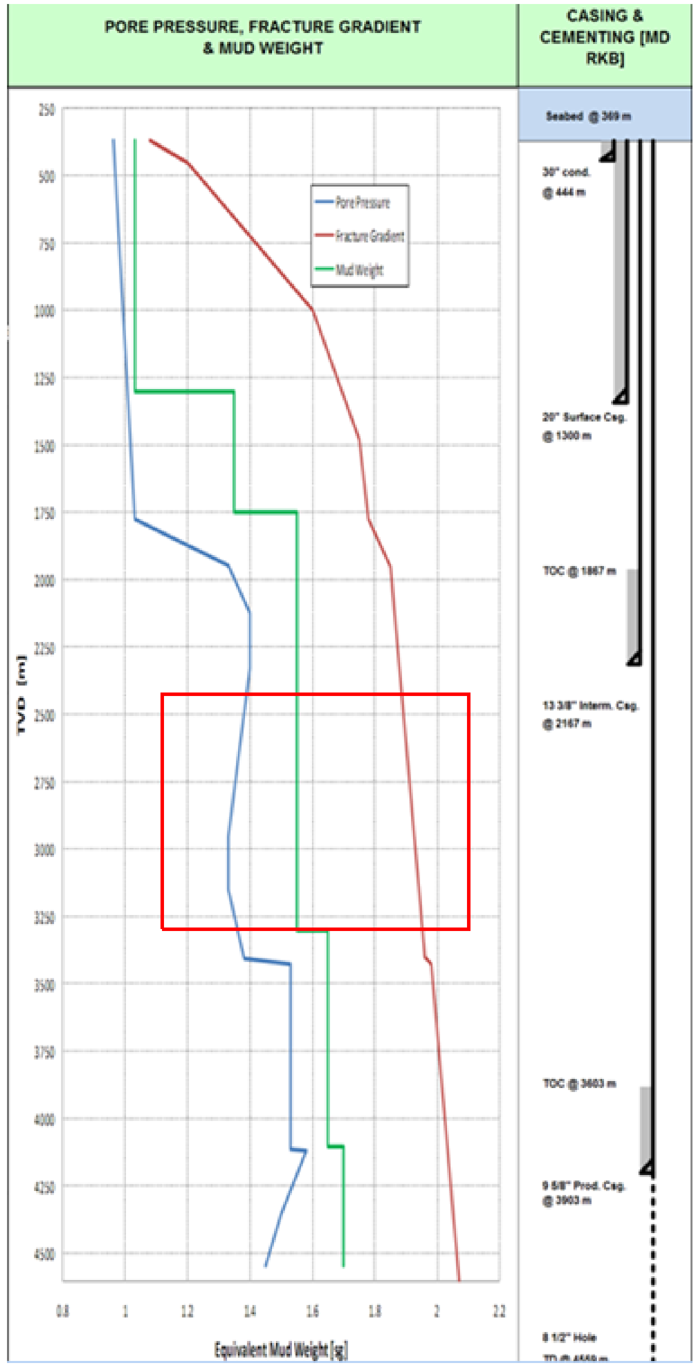


Figure 47 Pressure gradient chart for the Zidane well, with the problematic section marked with a red square (Source: Final drilling programme[9])

There was also an issue with the mud pumps onboard the drilling rig. The pumps could only deliver a hydraulic horsepower per square inch (HSI) through the nozzles of around 2.4hp/in^2 with the GeoPilot® downhole. When the motor was put down hole at around 3200m TVD the HSI dropped even further down to 1.85hp/in^2 with a flow rate of 2650lpm. The minimum flow rate when the motor was in use was actually 2200lpm, indicating that the HSI had dropped to 1.05hp/in^2. This reduction in HSI is due to the pressure drop over the motor, which in this case is calculated to around 30bar. Even if the mud pumps could have handled a higher flow rate, the SPP had reached the maximum allowable pressure for the drilling rig.

The recommended or ideal HSI is $4hp/in^2$ for WBM, and around $5\text{-}6hp/in^2$ for drilling in shale formations. That is a significant difference that can very likely have affected the drilling performance. To increase the HSI through the nozzles either the pumps had to be replaced, or the pressure drop in the drill string had to be reduced. This could be done by using a tapered drill string or 5.5" DP instead of 5". Changing the mud pumps or DP size is most like something that cannot be done on the Bredford Dolphin drilling rig since it requires extensive investment, but it is important to note when planning to drill deep wells with water based mud with the same drilling rig.

5.1.4. Formations

The top section of the Zidane well consists of several straight layers of rock. Down below the seabed and through Base Quarternary, Kai, Brygge, Tare, Tang and Springar formation the structure is very neat and not too complicated to drill through. Figure 48 on the next page shows this very nicely. One can also see that below Springar, marked as Base Tertiary on the figure, the subsequent layers starts to drop drastically. This is due to a phenomenon known as BCU. The BCU has created a basin for sediments to settle in, and as the mineralogical analysis of this shows most of this is shale deposits.

Based on the mineralogical analysis of clay samples done by RWE Dea AG the main shale mineral in this basin is smectite. Smectite is highly reactive when it comes in contact with water, but this can be properly mitigated with the right type and amount of additives in the drilling mud. When the smectite first appears on the logs it has a weight percentage of as much as 51%. It steadily decreases down to around 30% were it stabilizes through most of the shale sections.

The low ROP problems occurred in this shale section, however not before almost 200m of the highly concentrated smectite section had been drilled. When the problem started the level of smectite had actually decreased to 29%. This does not rule out the fact that the smectite most likely has played a significant part in the problem, but it does raise some important questions as to why it didn't occur earlier. Other factors such as bit type, hole cleaning, depth etc. could have played a part in preventing the problems from happening earlier but the exact cause is hard to determine. Table 5 on the next page shows the composition of the problematic zone in the Zidane well, whilst Figure 48 seismic image of the Zidane well. The complete lithostratigraphic summary can be seen in Table 6.

Table 5 Table showing the smectite, kaolinite, illite etc concentration in the shale section. (Source: Zidane1 XRD Analysis[10])

System	Group	Formation	depth (m)	XRD sample (no.)	Kaolinite (mass.- %)	K-feldspar (mass.- %)	Musc./ Illite (mass.- %)	Plagioclase (mass.- %)	Pyrite (mass.- %)	Quartz (mass.- %)	Smectite/ ML(SI) (mass.- %)
Tertiary	Rogaland	Tang	2120	8693	0	6	13	5	1	16	51
Cretaceous	Shetland	Springar	2280	8694	5	4	15	6	1	23	39
		Springar	2380	8695	5	6	13	10	1	27	29
		Nise/Kvitos	2580	8696	4	5	12	10	2	31	27
		Nise/Kvitos	2710	8697	6	3	12	7	1	32	30
		Nise/Kvitos	2870	8698	5	5	14	7	1	28	33
		Nise/Kvitos	2920	8699	6	4	10	10	1	32	29
	Cromer Knoll	Lysing	3000	8700	0	2	4	2	0	88	0
		Lange	3090	8701	0	0	0	1	0	6	0
		Lange	3280	8702	8	2	15	9	1	25	31
		Lange	3510	8703	9	2	15	9	1	22	28
		Lange	3640	8704	10	3	12	9	2	32	20
		Lange	3700	8705	7	4	10	8	2	36	21
Jurassic	Viking	Spekk	3790	8706	7	2	12	4	7	31	27
		Melke	3830	8707	11	2	21	3	4	22	24
		Melke	3900	8708	8	3	18	5	4	23	29

The well was displaced from WBM to OBM in the middle of the Lange formation, at 3289m TVD, and drilled to TD at 3947m TVD in the Melke formation.

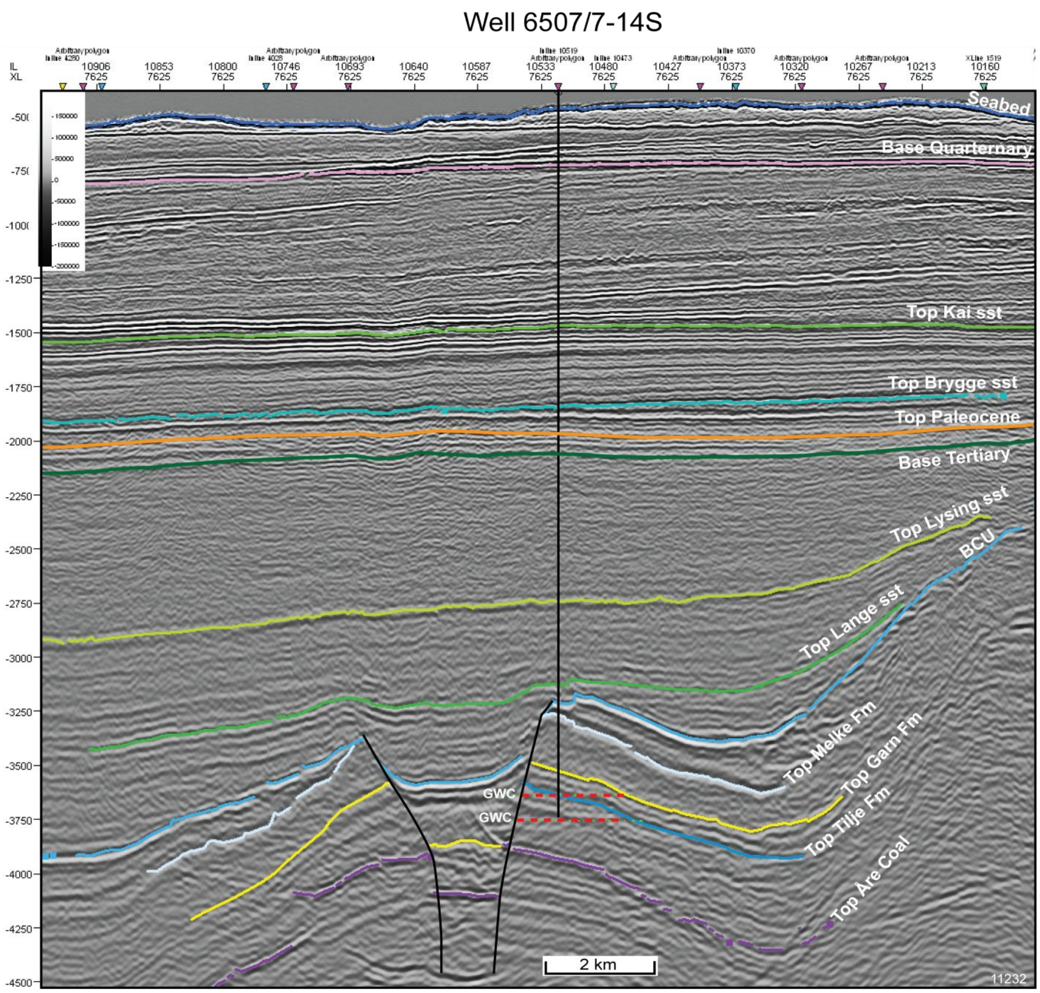


Figure 48 Seismic image of the Zidane well and the formation layers (Source: Final Drilling Programme[9])

Table 6 Lithostratigraphic summary of the Zidane well (Source: EOW report Zidane[8])

GEOLOGICAL SUMMARY OF WELL: 6507/7-14 S, Zidane 1

FORMATION TOPS	PROGNOSED		ACTUAL (PROVISIONAL)	
	MD RKB (m)	TVD RKB (m)	MD RKB (m)	TVD RKB (m)
Seabed /Nordland Gp Undiff	369	344	369	369
Base Quaternary	617	592	590	590
Kai Formation	1473	1448	1478.5	1478.5
Hordaland Group				
Brygge Formation	1852	1827	1910	1909.3
Rogaland Group				
Tare Formation	2014	1989	2034.5	2033
Tang Formation	-	-	2086.5	2084.3
Cretaceous / Shetland Group				
Springar Formation	2117	2092	2148	2144.8
Nise Formation	-	-	2470.5	2460.7
Cromer Knoll Group				
Lysing Formation	2947	2906	2972	2941.3
Lange Formation	-	-	3036	3001.0
Lange SST	3496	3454	3577	3522.1
Jurassic / Viking Group				
Spekk Formation	3676	3631	3767	3712.1
Melke Formation	-	-	3790	3735.1
Fangst Group				
Garn Formation	4168	4088	4217	4161.8
Not Formation	4231	4151	4291	4235.5
Ile Formation	4252	4172	4309	4253.5
Båt Group				
Ror Formation	4310	4230	4370	4314.2
Tilje Formation	4417	4337	4478	4421.5
Tilje Shale	4567	4487	-	-
TD	4580	4517	4534	4477.5

5.2. The Zidane Offset Wells

In the final pre-drilling report for the Zidane well there are 3 wells listed as offset wells. These are 6507/7-1, 6507/7-11S and 6507/7-12, all exploration wells owned by ConocoPhillips and drilled in the vicinity of the Heidrun area. Figure 49 below shows the position of the 3 offset wells on the Haltenbanken area approximately 200 kilometers off the coast of Norway. The first well, 6507/7-1, was drilled as early as 1984, so the information existing is limited and somewhat outdated. However, the information that does exist indicates that similar problems experienced in the Zidane well also occurred here. The 6507/7-11S well also had problems with low ROP, and this will be further discussed later in this section. Interestingly, the 6507/7-12 was drilled through much of the same formations as the 6507/7-14S but did not experience the same low ROP problems. This can be due to the fact that a large section of the well was drilled with OBM, but it could also be related to the use of a sodium silicate WBM. Silicate WBM is a potential countermeasure to the plastic shale problem, and this makes the 6507/7-12 a very interesting well to look into for this thesis.

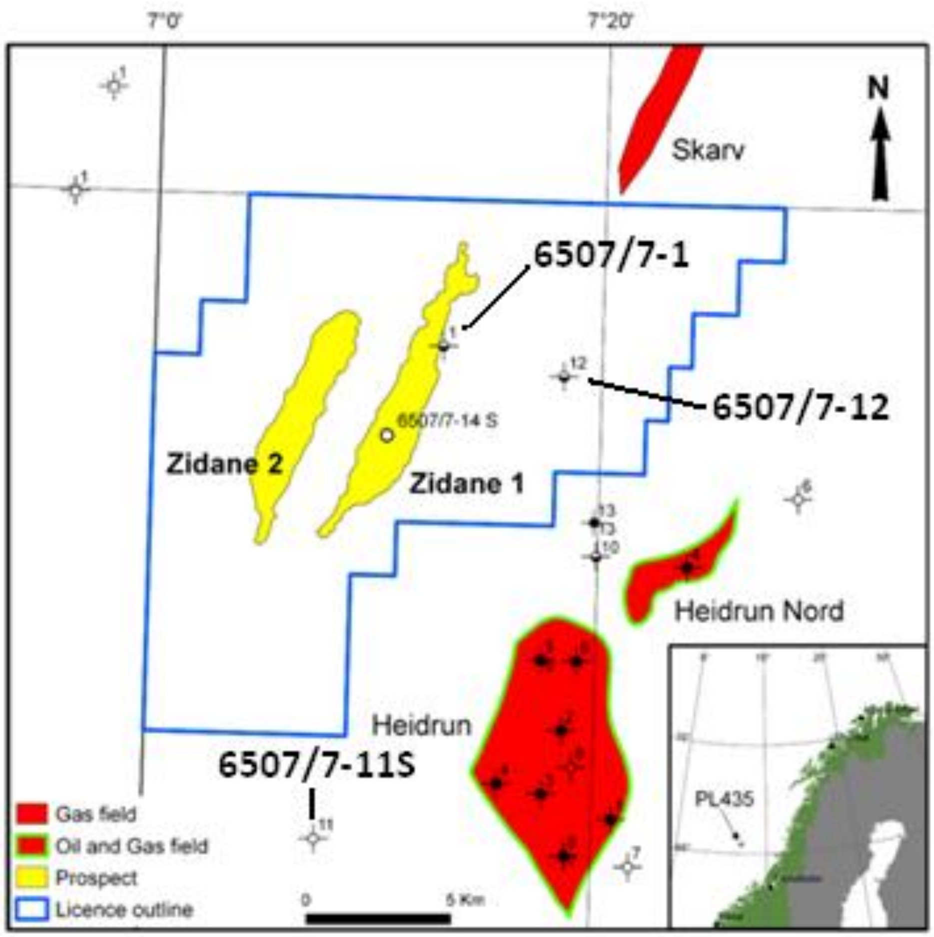


Figure 49 Map showing the positions of all the Zidane offset wells relative to the Zidane well itself (Source: Final Drilling Programme[9])

5.2.1. 6507/7-1

The first of the 3 offset wells to be drilled. The drilling started 10th of August 1984, and was completed 1st of December the same year. A total of 114 days was spent drilling the well using the Nortrym semisubmersible drilling rig. The water depth at the area was 392m and the well was planned to reach a total depth of 4818m TVD. It is situated a few kilometers north of the Zidane well, and south east from the Skarv field, as can be seen the Figure 49 on the previous page. WBM was used to drill the entire well. The following information has been gathered from the 6507/7-1 offset wells EOW report[5].

5.2.1.1. Bit Record

A total of 39 bit runs were performed. This was due to several causes as some bits were broken, and others had reached their limit of recommended drilling time for the bearings. Since this is an exploration well several coring runs were done resulting in even more bits being pulled and replaced than what normally would have been done. Between 1785m and 2193m depth the bit had to be pulled due to gumbo problems in the 17-1/2" section. Gumbo is another word used for a sticky formation that balls up on the bit and BHA. The ROP dropped to around 4m/hr, maybe even lower, and the mud weight was gradually increased from 1.28sg up to 1.51sg to try and mitigate the problem. Despite the gumbo problems only two bits were needed to drill the entire section to TD at 2193m MD. Including the bit used to drill out the previous casing shoe. Two rollercone bits, first from Smith and second from Hughes, were used without any problems apart from the low ROP. The average ROP for the entire section ended up at approximately 14m/hr.

17 bits had to be used to reach TD of the 12-1/4" section. Again rollercone bits were used and mostly mill tooth from Smith. Above 2743m MD slight gumbo problems had been experienced. However, no significant reduction in ROP was observed, nor any extra bit runs had to be performed due to this. Tight hole problems also occurred resulting in a lot of time spent reaming the hole open again. The mud weight was increased to 1.61sg to stop the surrounding formations from intruding the well.

Additional bit runs had to be performed to obtain core samples, but exactly how many the report does not say. The section was drilled without much problems, apart from the gumbo and tight hole issue, but the ROP from a depth of 3000m MD was generally very low. From 3000m MD and down to TD at 3820m MD the ROP varied between 1 and 5m/hr.

The 8-1/2" section was drilled with 18 bits, some of which were coring bits. Problems encountered in this section was tight hole and hard formations. An incident with leakage in the riser was also encountered, and a lot of time was spent to repair the leak. The report mentions shale swelling as the cause of the tight hole problems in the 8-1/2" section and that the drilling mud was adjusted to prevent this unwanted reaction. A lot of reaming still had to be performed to keep the borehole in gauge. The section TD was eventually reached with an average ROP of approximately 3m/hr.

5.2.1.2. Bottom Hole Assembly

40 different setups for the BHA were used in the well. This was due to several wiper trips, coring runs and logging tool failures. A standard setup of the BHA was for the most part used with stabilizers, drill collars, MWD tools and jars. No motors were used to enhance RPM or create a dogleg. As mentioned earlier reamers were also used several times to maintain gauge size of borehole. None of the equipment used for the BHA creates any flow restriction in the annulus nor do they take up much pressure on the inside before the bit nozzles.

5.2.1.3. Mud and Hydraulics

Seawater was used to drill the top-hole sections, meaning the 36" and 26" sections. The rest of the well, from 918m MD and down, was drilled with a gypsum and polymer based WBM. The mud weight started out at 1.28sg in the 17-1/2" section, and was gradually increased to 1.5sg. A leak off test performed at the previous casing shoe indicated the limit to be at 1.55sg. Problems with bit balling occurred several times as well and the mud was unable to prevent it. However, it was not considered a major problem and the drilling mud was not altered. The section was ended and cased at 2193m MD.

The 12-1/4" section started out with the same mud weight as the previous one, but was increased gradually up to 1.61sg as the depth increased. At around 3350m MD tight hole problems occurred and the mud weight was increased slightly to push the formation back and keep the hole in gauge. The new weight was then 1.64sg. At 3560m MD tight hole problems occurred again, and the mud weight was raised even further to a weight of 1.69sg. Drilling continued and TD was reached at 3820m MD with the previously mentioned mud weight.

For the 8-1/2" section the mud weight was reduced to 1.37sg. After drilling down to 4163m MD a leak in the LMRP-connector between the flex-joint and lower riser joint was discovered. The riser had to be detached to repair the leak, so the mud weight was increased to 1.39sg to compensate for the lost riser margin. Afterwards the weight was gradually increased up to 1.51sg to compensate for even more tight hole problems. In addition Soltex and 2-3% diesel was added to the drilling mud to prevent the drilled shale formations from swelling. The mud weight was then kept constant all the way down to TD at

4825m MD, but when several logging tools were unable to get to bottom due to tight hole, the weight was again increased up to 1.54sg.

With so many tight hole problems in the well it is clear that the mud did not have adequate properties to prevent the formation from swelling. Even when the additional additives were put into the mix it still didn't perform as hoped. This does not come as a surprise however since the well is older than the author of this thesis, and the behavior of shales were very poorly understood at the time.

5.2.1.4. Formations

The formations drilled are the Hordaland Group, Rogaland Group and parts of the Shetland Group. The Shetland Group is the same formation group in which the low ROP problems in the Zidane well occurred. Table 7 shows the litostratigraphic summary of the well. From the table it seems the formations drilled in this well are the exact same as those drilled in the Zidane well with less than 50m in difference for each formation layer top. This was expected as Figure 49 shows that the well is positioned right next to the Zidane reservoir.

As mentioned before the EOW report for this well is very old, and unfortunately it does not contain any information on the formations mineralogy and whether there are claystone or shale present, apart from what is said in the drilling summary.

The primary target area for the well was a possible oil bearing sandstone formation in the Middle Jurassic around 3900m RKB. Secondary target was the Lower Jurassic level. Unfortunately, only very small discoveries of hydrocarbons were made and the well was plugged and abandoned.

Table 7 Complete lithostratigraphic summary of the 6507/7-1 offset well (Source: EOW Report[5])

Formation Tops	Depth (m RKB)	Thickness (m)	TWT (m sec)
RKB	25	-	-
Nordland Gp	392	1091	497
Hordaland Gp	1483	570	1491
Rogaland Gp	2053	106	2001
Tare Fm	2053	49	2001
Tang Fm	2102	57	2043
Shetland Gp	2159	1521	2098
Springar Fm	2159	767	2098
Nise Fm	2400		
Kvitnos Fm	2824		
Cromer Knoll Gp	2926		
Lysing Fm	2926	71	2726
Lange Fm	2997	498	2772
Lyr Fm	3645	35	3209
Viking Gp	3680		
Spekk Fm	3680	105	3233
Melke Fm	3785	552.5	3310
Fangst Gp	4337.5		
Ile Fm	4337.5	140.5	3648
Ror Fm	4478	108	3715
Tilje Fm	4586	239	3766
TD	4825		3872

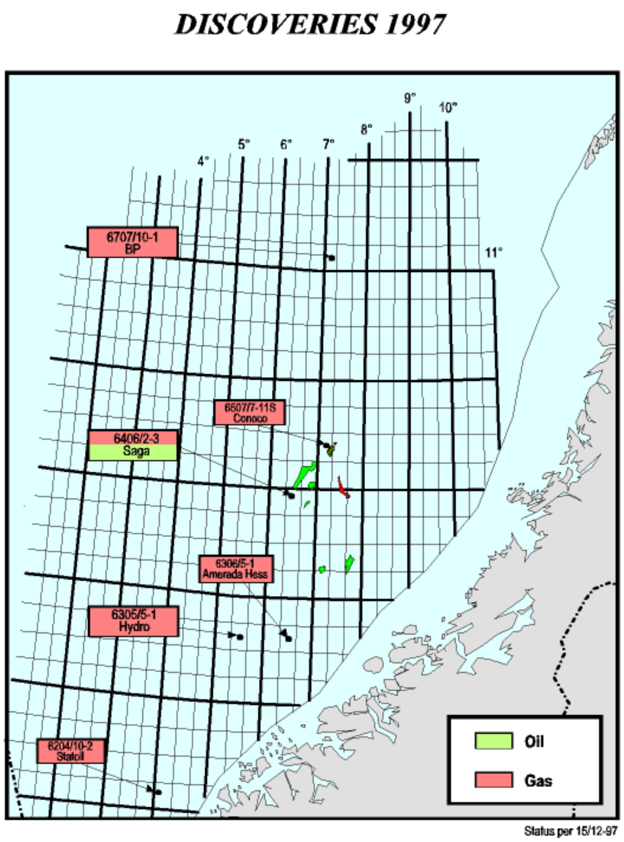


Figure 50 Map showing wells with hydrocarbon discoveries in 1997 (Source: www.npd.no)

5.2.2. 6507/7-11S

Almost 13 years later the next offset well had commenced drilling. It started 25th of June 1997 and lasted till 14th of August 1997. Approximately 51 days of drilling time. A semisubmersible drilling rig was used for this well as well, but this time they used the Mærsk Jutlander. The potential field to be discovered was named Heidrun SW, and is situated between the Smørbukk Field and the Heidrun Field. As the new fields name implies, the Heidrun Field is situated to the northeast whilst the Smørbukk Field is to the southwest. The Zidane well is situated around 16 kilometers north of this well. Due to the wells being so close to each other, the formation layers encountered are nearly identical. The depth of the layers is what differs between the two. Figure 50 to the left shows the 6507/7-11S well as one of the national gas discoveries of 1997. The source of information for this chapter is the offset wells EOW report[4] provided by ConocoPhillips.

5.2.2.1. Bit Record

The entire well was drilled with a total of 15 drill bits. The bits used were from Security DBS, Hughes Christensen and Smith Bits, with the majority coming from Security DBS. The top-hole sections did not create any problems, so only 2 bits where used for the 36” and the 26” hole. The 17-1/2” section required 2 bits because of excessive wear on the first bit resulting in low ROP. Problems did occur in the 12-1/4” section, and a total of 8 bits were used to reach TD.

The first bit, FS2663 PDC by Security DBS, drilled without any problems until it reached a depth of 2448m TVD. The bit became stuck due to tight hole, and the pipe had to be jarred free. After the jarring operation was done, the mud weight was increased to prevent any further tight hole problems. When the bit reached a depth of 2741m TVD, in the Kvitnos formation, it was decided to POOH and replace it due to low ROP. The bit was dull graded 1/1/PN/H/D/1/CT/PR, meaning it did not have much wear apart from a chipped tooth. The report does not mention the bit being balled up, so plastic shale might have been the problem. Average ROP was 17.5m/hr indicating that the bit performed well before the low ROP issue occurred.

Another PDC bit was put downhole. This time it was the Hycalog DS56. The bit drilled only 6 meters in 5.7 hours, average ROP was 1.05m/hr, and had to be POOH at 2747m TVD. With only 6 meters drilled it was still in the Kvitnos formation. At surface it was found to be very worn and balled up with a large amount of clay and pieces of hard dolomite, and nodules of pyrite. The bit was dull graded 6/8/PH/A/D/1/BT/PR, meaning high amounts of wear on the cutters with several of them being broken.

Since hard formations were observed it was decided to use a rollercone bit by Hughes Christensen, the GTP18, which was designed for hard formation drilling. The ROP increased slightly, 4-6m/hr, but the bit was able to hold it steady at that rate down to 3051m MD. Between 2899m and 2914m MD a drill break was observed, and the ROP reached 30m/hr. This was a sandstone layer and marked the top of the Cromer Knoll formation. At 3051m MD the bit lost one cone and had to be POOH. Onshore the bit was dull graded 3/3/LC/A/E/I/BT/TQ.

Several attempts to fish out the lost cone using a junk basket failed and a Junk Mill bit had to be run. The bit drilled 4 meters of new formation and a junk basked above it was found to contain junk weighing close to the weight of the lost cone. The Junk Mill was POOH.

A new rollercone bit, Halliburton DBS MM44NG, was run down hole to drill only around 20m of new formation. The reason for this was due to the risk of junk still being present at the bottom of the hole. It only managed to drill 3m in the Lange formation before it was POOH, and the junk basked above the bit contained more bits from the cone. The bit was POOH at a depth of 3058m MD and was dull graded 5/3/WT/A/E/1/BT/PR.

Since the previous Hughes Christensen bit, the GTP18, performed with a somewhat decent ROP it was decided to run another rollercone bit from Hughes Christensen of the same type, the GTC18. To avoid another lost cone problem it was decided to pull the bit when it would reach a predetermined amount of hours on the bottom. The bit drilled 202 meters through predominant shales, with occasional calcareous cemented sandstones and was POOH at 3260m MD, still in the Lange formation. Average ROP was 3.36m/hr and it was dull graded 4/4/NO/A/6/I/NO/TQ. Initially it was hoped to reach the sand layer of the Lange formation which was prognosed to be at 3250m MD, but no sand was seen and the bit had to be pulled due to the hours spent on bottom.

Again a rollercone bit was used. This time it was the 15MF by Smith Bits. It drilled with an average ROP of 2-3m/hr, until a drilling break was experienced and the ROP increased to 12-14m/hr. Shortly after the drilling break the bit had to be POOH. High torque and stand pipe pressure and a reduction in ROP raised concerns about the condition of the bearings. The bit was POOH at 3291m MD in the Lange formation and was dull graded onshore at 1/1/NO/A/E/I/NO/TQ.

The previous bit was intended to reach TD of the 12-1/4" section, but since it had to be pulled prematurely another Hugh Christensen bit was used to finish it. The bit was GTP18D rollercone and had a steady ROP of 2-3m/hr. The bit reached TD at 3365m MD and was dull graded 4/4/NO/A/E/I/WT/LOG. The sections TD ended at the top of the Melke formation.

Two bits were used to drill the final 8-1/2" section. GTP18D rollercone bit from Hughes drilled the first part from 3365m MD down to 3461m MD with an average ROP of 6.9m/hr. A coring run was performed down to 3488m MD to look for indications of hydrocarbons. After the coring run was performed FM2745R PDC bit from Halliburton DBS was put in hole to drill to TD. With an average ROP of 13.8m/hr the bit reached TD at 3749m MD. The 8-1/2" section started in the Melke formation and went through Garn, Not, Ile, Båt and Ror until it reached TD in the Tilje formation.

5.2.2.2. Bottom Hole Assembly

The BHA includes the bit, so technically it is changed every time the bit has to be changed, in this case 15 times. Despite this the rest of the BHA was kept constant for each section, except for the 12-1/4" section. Initially a 9-1/2" motor with 12-1/8" sleeve was used and a 12" near bit stabilizer. The rest of the BHA was no larger in OD than 8". When the problem with the lost cone was encountered the motor and bit were swapped with a Reverse Circulation Junk Basket to fish out the junk in the well. As mentioned in the Bit Record these attempts failed and the Junk Mill had to be put to use. Figure 51 shows what a Reverse Circulation Junk Basket looks like.

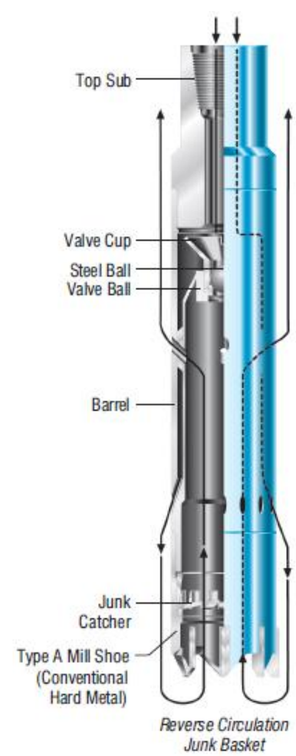


Figure 51 Reverse Circulation Junk Basket (Source: www.alakdharoman.com)

Once the problematic cone was dealt with, a new BHA was put together with two 12-1/4" stabilizers as the largest parts apart from the bit. No information on the size of the near bit stabilizer, Pin/pin sub, MWD and Float sub is in the report, so it is hard to tell if these parts might have created a flow restriction for the cuttings and cause a lower ROP. Most likely these parts are reused for the 8-1/2” section, meaning they have to be smaller than 8-1/2”.

5.2.2.3. Mud and Hydraulics

The problematic 12-1/4” section was drilled using a KCL Polymer WBM. At the start of the section the mud weight was 1.35sg. It was gradually increased to 1.40sg and kept constant at this weight until a depth of 2448m MD was reached. At this depth problem with stuck pipe occurred. The pipe had to be jarred free, and it was decided to increase the mud weight to 1.55sg. They continued to drill without problems but decided to increase the mud weight even more, to 1.57sg, to help with possible tight hole issues. ROP steadily decreased and the 1.57sg mud weight was thought to be the reason for this. They decreased the mud weight to 1.55sg again but eventually decided to pull the bit out of hole and change it. The average ROP with 1.55sg was around 10-11m/hr, and declined to around 8-7m/hr when it was raised to 1.57sg. If this decline in ROP was in fact due to the increase in mud weight and not due to the increase in depth is hard to determine. What is apparent however is that the ROP did increase slightly when the weight was reduced again, but then steadily declined until the bit was eventually POOH. At the end of the bits run, at 2746m MD, the ROP had dropped to an average of 2-3m/hr. The flow rate was kept at a constant 3200lpm, but raised to 3400lpm at the end of the run. It did not have any noticeable effect on the ROP. As mentioned in the bit records chapter the bit was dull graded 1/1/PN/H/X/I/CT/PR, which meant it was only mildly worn.

For the next bit run the mud weight was increased even further. The weight was 1.65sg. This was done to prevent tight hole problems according to the well report. Since the bit was found to be much worn when analyzed at surface, the high mud weight did not necessarily have to be the cause of the extremely low ROP of 1.05m/hr. Only 6 meters were drilled during this run.

The mud weight was eventually increased to 1.7sg and kept there for the remainder of the 12-1/4”. The ROP continued to decline, and when the section reached TD at 3365m MD the average ROP was only 2-3m/hr.

For the 8-1/2” section the mud weight was lowered to 1.2sg. This section was also drilled through some shale and claystone layers, but a decent ROP was still obtained. ROP ranged from a relatively ok speed of 6.9m/hr and up to a much faster rate of 33.8m/hr. The same KCL Polymer WBM that was used in the 12-1/4” was also used for the 8-1/2” section indicating that the low mud weight might have had a positive effect on the ROP. However, drilling an 8-1/2" hole is usually more efficient than drilling a 12-1/4" hole. The pore pressure was around 1.06s.g so it was still drilled overbalanced.

5.2.2.4. Formations

In the EOW report there are thorough visual and physical analyses of the cuttings encountered in much of the well. According to the report the well is dominated by claystone formations through the entire 12-1/4" section. Some sandstone and limestone stringers were encountered as well, and at the end of the section mostly shales were drilled through. The ROP at this point was 3.36m/hr with a rollercone bit. The shale is described as dark grey to moderate grey with a hard to firm appearance in the upper part and soft to firm for the rest of the layer. Table 8 shows the litostratigraphical summary of the 6507/7-11S well. The Fangst Group, Tilje and Åre formations were to be tested for presence of hydrocarbons. No viable sources of hydrocarbons were detected in these formations and the well was permanently plugged and abandoned.

Table 8 Complete litostratigraphic summary of the 6507/7-11S well (Source: EOW report[4])

	Prognosed depth			Observed depth			
	m MD RKB	m TVD RKB	m MSL	m MD RKB	m TVD RKB	m TVD SS	Differ-ence
SEABED	297	297	274	297	297	273	-1
NORDLAND GROUP	297	297	274	297	297	273	-1
Quarternary	297	297	274	297	297	273	-1
Top Kai Fm.	1523	1523	1500	1509	1504	1481	-19
HORDALAND GROUP	1967	1967	1944	1857	1852	1829	-115
Top Brygge Fm.				1857	1852	1829	
ROGALAND GP.	2098	2098	2075	2072	2067	2044	-31
Top Tare Fm.				2072	2067	2044	
Top Tang Fm.				2158	2158	2135	
SHETLAND GROUP	2212	2211	2188	2189	2184	2161	-73
Springar Fm.	2212	2211	2188	2189	2184	2161	-73
Nise Fm.				2230	2225	2202	
Kvitnos Fm.				2321	2316	2293	
CROMER KNOLL GP.	2899	2895	2872	2901	2896	2873	+1
Lysing Fm.	2899	2895	2872	2901	2896	2873	+1
Lange Fm.	2934	2930	2907	2914,5	2910,5	2887,5	-19,5
Lyr Fm.				3322	3317	3294	
VIKING GROUP	3347	3343	3320	3327	3322	3299	-21
Spekk Fm.				3327	3322	3299	
Melke Fm.	3347	3343	3320	3348	3344	3321	+1
FANGST GROUP	3380	3376	3353	3458	3454	3431	-78
Garn Fm.	3380	3376	3353	3458	3454	3431	-78
Not Fm.				3476	3472	3449	
Ile Fm.				3497	3493	3470	
BÅT GROUP	3552	3548	3525	3558	3555	3532	+7
Ror Fm.	3551	3548	3525	3558	3555	3532	+7
Tilje Fm.	3660	3656	3633	3615	3611	3588	-45
Åre Fm.	3807	3803	3780	np	np	np	
TD	3930	3926	3903	3749	3744	3721	

5.2.3. 6507/7-12

The last of the three offset wells to be drilled was commenced 17th of July 1999 and ended 12th of August the same year. Only 27 days were spent drilling the well, and the Mærsk Jutlander semi-submersible drilling rig was used again. The well is situated 14 km northwest of the Heidrun TLP, approximately half that distance to the east of the Zidane 6507/7-14S well. Figure 52 to the right shows the position of the 6507/7-12 well relative to the Heidrun field. The other 2 offset wells can also be seen in the figure, but the Zidane field was not discovered at the time and therefore is not included. It is located 200km off the Norwegian coast with a water depth of around 333m MD. The main target to test for hydrocarbons was a sand prone wedge of Albian age, Lower Cretaceous, with the Aptian, Lange B and Lysing Formation as secondary targets. Total well depth was planned to end at 3908m RKB approximately 20 meters into the Upper Jurassic Spekk Formation. The general information on the 6507/7-12 offset well is gathered from the Norwegian Petroleum Directorate (NPD) fact pages, but the following information refers to the wells EOW report[1].

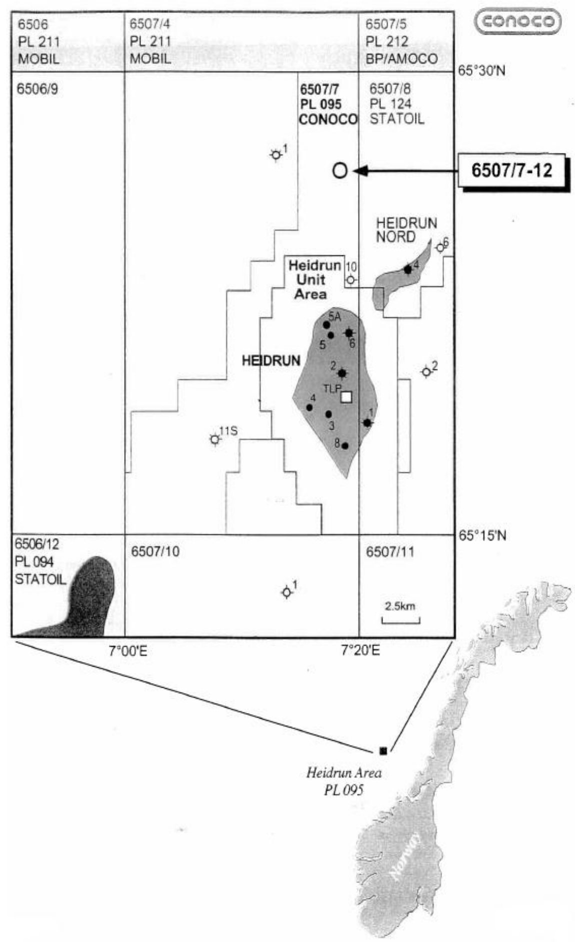


Figure 52 Map showing the position of the 6507/7-12 well (Source: EOW Report[1])

5.2.3.1. Bit Record

A total of no more than 5 bits where used to drill the entire well. Two 17-1/2" rollercone bits from Hughes Christiansen, one 12-1/4" PDC bits from Smith, one 8-1/2" PDC from Security DBS and one 8-1/2" PDC from Hycalog.

The first 17-1/2" rollercone bit was drilled in conjunction with a 36" hole opener and reached TD at 418m MD without any problems. There was only slight wear, with a dull grade of 1/2/FC/G/E/I/FC/TD. The dull grade indicates very little wear on the teeth, bit still in gauge and bearings still intact. No problems occurred during the second bits run either, and it reached TD at 1316m MD with a decent average ROP of 57.9m/hr. The bit was dull graded almost identical as the first bit.

In the 12-1/4” section a MA74PX PDC bit from Smith was the first one to drill. The bit drilled for 14.6 hours reaching a depth of 1933m MD, middle of Brygge formation. The bit had performed well, with an average ROP of 42.3m/hr, but had to be pulled due to a malfunctioning MWD tool.

The bit was found to be very little worn, and was therefore put back into the hole. Again the bit performed very well, and drilled to TD at 2508m MD with an average ROP of 40.7m/hr ending with a dull grade of 3/1/CT/N/D/I/CT/DTF. TD of the section was in the Nise formation. Some problems did occur towards the end of section due to poor cuttings removal and high ROP, but this was not bit related. A pack off incident also occurred at 2114m MD, and it was believed to be related to green marker clay above the Tare formation which most likely created some over pressure and over pull seen on trip out.

For the 8-1/2” section the first bit to be put to work was the Halliburton DBS FS274S PDC bit. The bit performed well with a stable ROP of 40m/hr. However, towards the end of the bits run the ROP declined rapidly and so much that at a depth of 3814m MD, bottom of the Aptian formation, it was decided to pull the bit out of hole and replace it. At the end it had dropped below 3m/hr. The bit was slightly worn with a dull grade of 1/7/WT/S/D/I/PR. The 8-1/2” section was drilled with an OBM and so plastic shale or bit balling is probably not the cause of the low ROP. Bit balling cannot be excluded however since it is known to occur even when using OBM.

The next bit, Hycalog DS66DGNSW, was put in hole to finish of the section and reach TD at 3976m MD in the Spekk formation. The ROP of the bit started out between 3-6m/hr, a mild improvement from to the previous bit, and increased to 8-10m/hr towards the end of the run. The JSA of this bit was 0.842in2, whilst the previous Security DBS bit had a JSA of 0.738in2. If the low ROP was due to bit balling, then the increase in JSA might be the reason for the slight increase in ROP for the Hycalog bit. The increase in JSA will make it easier to prevent cuttings from sticking to the bit surface.

All in all very little problems occurred with the bits apart from the low ROP in the final section.

5.2.3.2. Bottom Hole Assembly

The BHA did not go through many changes during drilling of the well. Apart from some apparent changes due to the differing hole sizes for each section the BHA was for the most part kept constant. One incident with the MWD tool however made it necessary to POOH and replace it with a backup tool.

At 1933m MD the MWD failed to transmit its signals to surface, and at the workshop back onshore it was found that some rubber probably from the pumps had got stuck inside the tool and prevented it from working properly.

The MWD tool malfunctioning did not affect the ROP in the 12-1/4" in a negative manner. On the BHA only three stabilizers had a larger OD than 8" behind the bit. The stabilizers had an OD 12-1/4", but they are designed to not create too much flow restriction for the cuttings and should not prevent proper hole cleaning. From the very high ROP in the 12-1/4" section it is obvious that they didn't affect hole cleaning in a negative manner.

In the 8-1/2" section however, the space between the borehole wall and the BHA equipment in general is much smaller, and it is a possibility that it contributed to the decreasing ROP in the final part of the section when it comes to BHA balling.

5.2.3.3. Mud and Hydraulics

Both the 36" and the 17-1/2" section were drilled with seawater. The cuttings were therefore disposed on the seabed. For the 12-1/4" section a more advanced WBM with sodium silicate, KCl/Barasilc, was used to keep the borehole stable and in gauge, and prevent other unwanted reactions with the drilled formations. KCl/Barasicl is a WBM with sodium silicate and potassium chlorite specifically designed for drilling in reactive shale formations. The mud weight was kept between 1.53-1.54sg through the entire section with a flow rate varying between 3200-3700lpm. The mud performed very well with no borehole stability problems and an average ROP for the entire section of 41m/hr. At the end of the section the ROP averaged around 20m/hr. The EOW report states that the silicate mud system exceeded expectations maintaining a stable borehole wall and assisting the bits ROP.

For the 8-1/2" section the mud was changed from the KCl/Barasilc WBM over to Baroids Enviromul OBM. The mud weight was kept at the same level as before with 1.54sg at the start of the section, but was later increased to 1.57sg due to an increase in pore pressure. Since this is an OBM the flow rate could be lowered and still maintain good hole cleaning. The rate was lowered from 3300lpm down to 2450lpm. No problems did occur due to the mud with respect to hole cleaning and wellbore stability. There were some problems experienced with maintaining the O/W ratio and salinity. It was eventually discovered that a small leakage of seawater at the shakers had been the cause of these issues. The drilling continued without any problems, but as mentioned earlier problems with low ROP occurred. No changes were made to the drilling mud, but the bit was replaced. The ROP was still very low and could potentially be related to the fluid-formation interaction.

5.2.3.4. Formations

From depths between 1325m MD 3976m MD several cutting samples were analyzed at well site, using a binocular microscope and an ultraviolet light box. In the 12-1/4” section claystone is the dominant formation type. The claystone was occasionally very hard due to siliceous cementation, showing that the silicate WBM did interact and react with the drilled cuttings. In the Zidane well the low ROP problems started to occur at a depth of 2412m MD, whilst the 6507/7-12 offset wells 12-1/4” section ended at a depth of 2508m MD, in the same formation, without having problems with low ROP.

Table 9 Complete litostratigraphic summary of the 6507/7-12 well (Source: EOW report[1])

Group	Formation	MD (m)	TVD (m)	TVDSS (m)	TWT (ms)
Nordland Gp	Naust Fm				
	Kai Fm	1492	1492	1468.8	
Hordaland Gp	Brygge Fm	1877	1877	1853.8	1785.68
Rogaland Gp	Tare Fm	2099	2099	2075.8	1990.67
	Tang Fm	2152	2152	2128.8	2038.72
Shetland Gp	Springar Fm	2196	2196	2172.8	2078.76
	Nise Fm	2377	2377	2353.8	2240.79
	Kvitnos Fm	2595	2595	2571.8	2420.75
Cromer Knoll Gp	Lysing Fm	2857.5	2857.4	2834.2	2623.6
	Lange Fm	2897	2896.9	2873.7	2649.34
	Top Aptian sst	3670	3669.5	3646.3	3167
Viking Gp	Spekk Fm	3910.5	3908.7	3885.5	3305.9
TD		3976	3973.6	3950.4	

Claystone is also the dominant formation type in the 8-1/2” section, but some shale did exist here as well. In the lower part of the section from 3700m MD down to 3976m MD, where there was experienced low ROP, some shale formations did appear. This was in the mid Aptian and top Spekk formation and deeper than the low ROP section of the Zidane well. OBM is supposed to be excellent in terms of drilling shale formations and preventing any unwanted reactions. However, in this case there was a situation with high water content in the drilling fluid due to the leakage. It is difficult to tell if this actually had an impact on the ROP, or if other factors played a more pivotal role in reducing the drilling rate.

Layers, stringers and beds of sandstone, limestone and dolomite also occur regularly in the well. None of which seem to have impacted the drilling performance in a negative manner, at least not significantly. As mentioned earlier the primary target was the sand prone wedge in the lower cretaceous area, Kvitnos formation, and the secondary targets were the Aptian, Lange B and Lysing formations. Table 9 shows the lithostatigraphical summary of the well, and Figure 53 shows a 2D seismic image around the well and the actual well path. The well had indications of oil, but not enough to be viably produced and was therefore permanently plugged and abandoned.

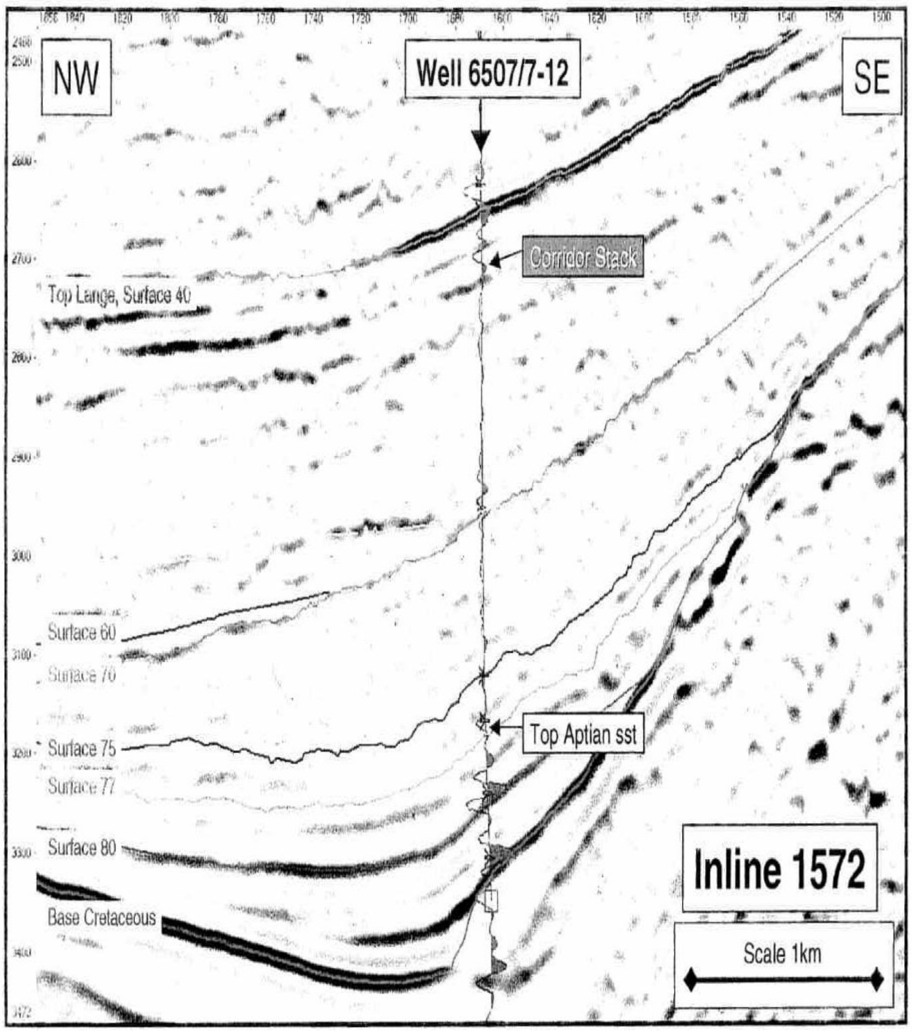


Figure 53 Seismic image of the 6507/7-12 well (EOW report[1])

5.3. The Heidrun Field

As previously mentioned there were 3 ConocoPhillips wells chosen as offset wells for Zidane. However, the Heidrun Field run by Statoil is almost as close as the offset wells are and could potentially be very relevant to the study of this case. With that in mind 2 randomly selected wells from the Heidrun Fields, Figure 54, have been chosen to represent it and be compared with the Zidane well, 6507/7-A-18 and 6507/8-D-3H. The drilling standards used here have shown promising results that could be very relevant with respect to deep shale formation drilling.

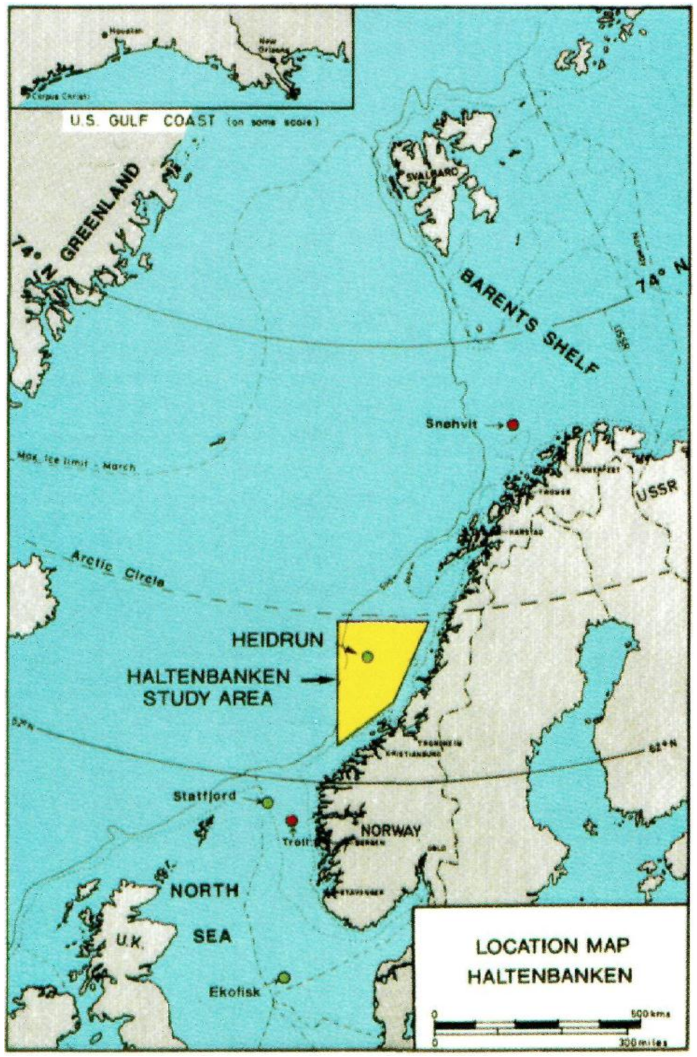


Figure 54 Map showing the position of the Heidrun fields in the Haltenbanken area (Source: http://search.datapages.com)

It was first discovered in 1985 and put to production 10 years later. The field is produced from the Heidrun TLP installed over a 56 well slot template. In 2000 the PDO for the Heidrun North reservoir was approved and subsea installations were constructed to produce it and tie back to the Heidrun TLP. The reservoir was discovered in sandstone formations in the Garn, Ile, Tilje, and Åre formations with a depth of about 2300m TVD. Both oil and gas are produced from the reservoir with water and gas injection to maintain a stable production rate. Recoverable reserves are estimated to 169 million Sm3 oil and 43.2 billion Sm3 gas with 33.9 million Sm3 oil and 30.1 billion Sm3 gas currently left in the reservoir. The prognosed reserve was actually reduced in 2009 based on a new reservoir model and fewer wells drilled than planned. To increase oil recovery new well targets are continuously being considered.

5.3.1. 6507/7-A-18

Drilling started 29th of March 1998 and ended 8th of May the same year. The well was temporarily abandoned at this time and reentered to be completed the 1st of August 1998. It took approximately 40 days to drill. The primary target formation was the Tilje Oil Producer, and it was to be drilled from the Heidrun TLP. To reach the target the well was planned to be 4208.5m long from RKB with a maximum wellbore deviation of 78.4°. TD was reached at a depth of 2654.5m TVD with 5 different sections drilled. The information documented in this chapter is based on reference [2].

5.3.1.1. Bit Record

6 bits were used to drill the well. The 30" conductor and a 22" surface liner was already installed during a pre-drilling phase. A 17-1/2" rollercone bit and reamer was used to open the surface liner shoe track and a new 18-5/8" casing was set.

Lack of information in the bit record makes it difficult to determine the type of bit used in the 17-1/2" section. However, the most likely type of bit used is a rollercone bit. From the EOW report it says a 17-1/2" bit with a steerable assembly was used. Two bit runs were performed from 1455m MD down to 3355m MD, 1884m TVD in the Brygge formation, with an average ROP of 34.1m/hr. The first bit had to be pulled due to twist off in MWD which can happen due to stick-slip or pack-off. No explanation for the twist off exists in the EOW report. The sections inclination was increased from 48.3° up to 76.2°.

For the 12-1/4" section a G426DKG2 PDC bit from HTC was used. The bit drilled from 3355m MD through Brygge, Tare, Tang and Springar formation and into the Ror formation at 4106m MD, 2363.5m TVD, in one run. Inclination was decreased from 76.1° down to 19.5°. Average ROP was at a decent 26.2m/hr with approximately 4450lpm flow rate at bit. WOB is not mentioned in the bit record or the EOW report. Pressure built-up and tight hole did occur and created some problems, but according to the EOW report this was expected based on experience from earlier wells.

A new rollercone bit was put to use in the 8-1/2" section, EHP51AFLDH by REED. It drilled from 4106m MD through Tilje formation and down to TD in the Åre formation at 4411m MD, 2654.5m TVD, in one run. Average ROP was at 13.9m/hr with the section ending at an 18.3° inclination. No information is found with respect to WOB and flow rate at bit.

A short 6" section was drilled with a rollercone bit from 4193.5m MD down to 4208.5m MD, 2458.1m TVD. To save time and to eliminate one run/pull of drilling riser a production riser was run instead. Inclination was kept constant at 18°.

5.3.1.2. Bottom Hole Assembly

Apart from an MWD tool twist-off during drilling of the 17-1/2" section, not much information about the BHA exists in the EOW report. A steerable assembly was used to create an inclination on the well path and bring it back again further down. No downhole motors were used.

5.3.1.3. Mud and Hydraulics

As is standard for the most part when drilling offshore the first sections, in this case the 24" section, are drilled by using seawater. High viscosity pills were also used, and the mud weight therefore varied between 1.1-1.2sg. The flow rate was kept stable at 5500lpm, except for when the section was back reamed. Then the flow rate was increased to 6000lpm.

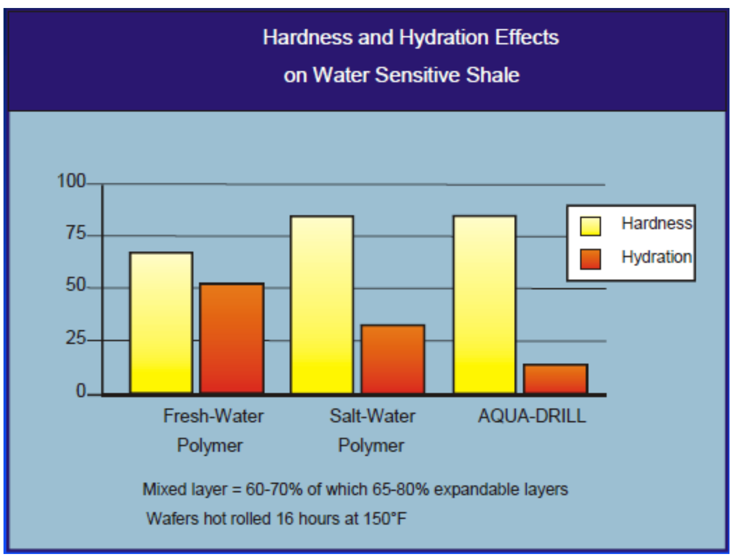


Figure 55 Hardness and hydration effects on water sensitive shale with different WBM systems (Source: www.eng.rpi-inc.ru/)

For the 17-1/2" a WBM system called Aquadrill D was used. Aquadrill D is described as a high performance, environmentally responsible, alternative to conventional inverts and synthetics. Most importantly it contains water-soluble glycols for drilling in reactive shales. Figure 55 shows a comparison of the hardness and hydration effects on water sensitive shale between the Aquadrill and polymer WBM systems.

Mud weight was increased gradually from 1.21sg to 1.45sg in the 1900m drilled. No problems with wellbore stability were encountered, but 8-9m3 mud was lost in a sand zone at the top of the Brygge formation. Flow rate for the section is unknown since there is missing information both in the EOW report and the drill bit database at Halliburton.

For the 12-1/4" section the mud weight was kept constant at 1.48sg. The same WBM system used in the previous section was also used here. Problems with pressure build-up and tight hole occurred in this section, but this was expected and solved by back reaming. Overloads of cuttings in the annulus also became an issue, probably due to the high inclination. To maintain proper hole cleaning the flow rate was kept stable at 4450lpm. No problems were experienced during the following casing run, and the casing was cemented in position without any problems. In the EOW report the low mud weight of 1.48sg is mentioned in the lessons learned to possibly be recommended for future wells.

The same WBM system was used again, but the mud weight was decreased to 1.18sg for the 8-1/2" section. No problems occurred when drilling the section, and after back reaming was performed the hole was found to be in good condition. Again there is missing information on the flow rate, except for the back reaming operation where the rate was 2150lpm. The flow rate during drilling was most likely much higher than this, and probably close to that of the previous section. Only 300m of formation was drilled for this section.

The 6" section was only a minor operation with only 2.5m of new formation drilled. Same mud was used again and the mud weight was almost the same at 1.19sg. This section was so short and finished so fast that no borehole problems could occur. All in all the Aquadrill D WBM system seem to have performed very well, with only slight problems with tight hole. Figure 56 on the next page shows the plot of the mud weight with respect to pore pressure, fracture pressure, overburden weight and LOT/FIT tests.

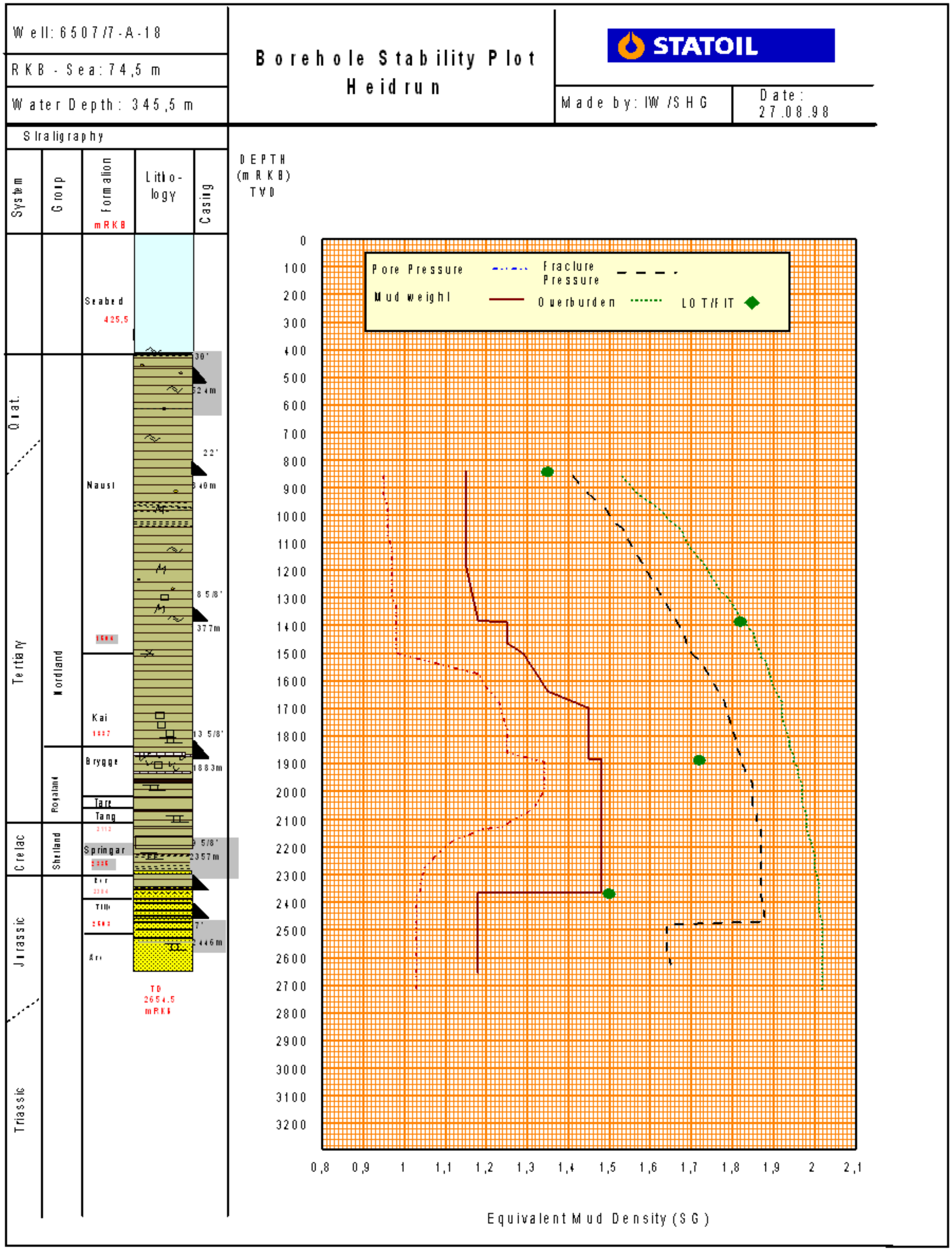


Figure 56 Pressure gradient plot for the 6507/7-A-18 well (Source: EOW report[2])

5.3.1.4. Formations

Unfortunately the EOW report for this well contains very little information about the formations drilled. There is mentioned a sandstone layer at the top of the Brygge formation, and indications of shale layers in the 12-1/4” section, which are the Brygge, Tare, Tang, Springar and Ror formations. Information acquired from Statoil via email confirms that clay minerals such as smectite, kaolinite and illite are present in the field. Depth and formation layers in which these minerals exist are unknown. It is probable however that they exist in the Springar formation, in which the smectite mineral group occurred in the Zidane well.

Table 10 below has been put together using the information from the Figure 56 on the previous page, and the depths are therefore not completely accurate.

Table 10 Complete litostratigraphic summary of the 6507/7-A-18 well (Source: EOW report[2])

System	Group	Formation	TVD Depth (m TVD RT)
Quatenary/Tertiary	Nordland	Naust	425
		Kai	1506
	Rogaland	Brygge	1847
		Tare	2020
		Tang	2070
Cretacious	Shetland	Springar	2112
Jurassic/Triassic		Ror	2310
		Tilje	2395
		Åre	2525

The depths represent the top of each formation in TVD measured from the rotary table on the drilling rig. Upper and Lower Tilje formation was the primary target for the well, where it was supposed to produce oil at an estimated rate of 3000Sm3/D. It ended up producing way less than that, and was therefore plugged.

5.3.2. 6507/8-D-3H

The second well was situated in the Heidrun North field and was initially supposed to be drilled from the E template, but the template got unstable during a previous operation and sunk into the seabed. It was therefore decided to move the drilling rig to the D template and drill from there. Drilling of the well started in 1999 at the 20th of December and ended the 18th of February 2000. Due to poor reserves the well was plugged and abandoned. One and a half year later a slot recovery was performed on the same well. The operation started 5th of September 2001 and ended 25th of October the same year. Both the initial operation and the slot recovery operation will be documented in this section based on references [6] and [25].

5.3.2.1. Bit Record

The bits used to drill the initial well path performed extremely well, and only 4 bits, apart from the coring bits and the 26" bit used to drill out the previously set 30" casing shoe, were needed to complete it.

Hughes MAXGTPT-03 rollercone bit drilled the 17-1/2" section in one run with an average of 42.9m/hr. The section was drilled from 525m MD and down to TD at 1490m MD, 1316m TVD, and ended with a 51° inclination. A 20" x 13-3/8" casing was run with the 13-3/8" cross over just below the 30" casing shoe. This made it possible to drill a 17-1/2" sidetrack at a later stage if necessary. Information on this bits run does not exist in the drill bit database, and very little is said in the EOW report. WOB and flow rate is therefore unknown.

The 12-1/4" section was drilled with the Halliburton DBS FM2643 DRI/2 PDC bit with 9 vortex nozzles. It drilled from 1490m MD through the Kai, Brygge, Tare, Tang, Springar, Garn, Not, Ile and Tilje formations, and into the Åre formation at 2812m MD, 2335m TVD, with an average ROP of 45.6m/hr. The flow rate was maintained at a constant 4000lpm through the entire 12-1/4" section. According to the EOW report no bit balling occurred. Dull grading was not found for the bit in the DBS database nor the EOW report. The bit had actually reached an ROP of 54m/hr, which was believed to be the cause of some pack-off tendencies in the upper part of the section. A back reaming operation was therefore performed to clean the hole. The well inclination was reduced down to 27°.

To drill into the reservoir section in the Åre formation two bits from Hughes were used. One rollercone bit, MX18DX, and one PDC bit, DP0008. The rollercone bit only drilled 20 meters down to coring point, and was not used again after the coring runs. No information on its performance is mentioned in the

EOW report. The PDC bit finished the section after the coring runs were done with an average ROP of 29.5m/hr. After reaching TD the well was temporarily plugged and abandoned. There was no dull grading available for these two bits either.

The well was reopened at a depth of 1316m MD, 1200m TVD, and a 12-1/4” sidetrack was drilled with the help of a whipstock. The first bit was the LD565ATHG PDC by Lyng which drilled the section to TD at 2827m MD, 2382m TVD, with an average ROP of 29m/hr. Again no dull grading was available. WOB used was 0-5 tons in the Naust and Kai formations, and 0-13 tons in the BTT and Springar formations. Flow rate was at 4100lpm through the section. Initial inclination at 45° was increased up to 60° prior to entering the reservoir, and was eventually decreased down to 38° at TD, 39m MD into the Åre formation. Tight hole was experienced, but a subsequent check trip showed no restrictions.

The final 8-1/2” section in this well path was also drilled with two bits, apart from the coring bits. MXC18DX insert rollercone bit from Hughes was used to drill the first 61 meters down to coring point, and LA331TBG PDC bit by Lyng was used to drill the section to TD in the Åre formation. The rollercone bit had an average ROP of about 8m/hr, and the PDC bit reached an average ROP of 29.5m/hr. In other words, very decent drilling rates.

5.3.2.2. Bottom Hole Assembly

The EOW report for the original well path contains almost no information about the BHA. It only mentions that MWD tools and a downhole steerable system were used for most of the sections. Same goes for the DBS bit database which sometimes contains information on the BHA too, but in this case it does not.

For the 12-1/4” section in the slot recovery operation the BHA contains the Autotrak for downhole steering and a full package of logging tools (GR/RES/PWD/DEN/NEU). No sizes are mentioned.

In the 8-1/2” section most of the logging was performed with wireline, so the BHA used was with a motor together with an insert tri-cone bit. That is however the only information on the BHA in the 8-1/2” section in the EOW report.

5.3.2.3. Mud and Hydraulics

The first sections in the original wellbore, including the 17-1/2” section, were drilled with seawater with cuttings discharge directly to the seafloor. For the 12-1/4” and 8-1/2” section the Glydril WBM, a WBM system with glycol, was used to decrease the mud reactivity with the drilled formations. The mud weight in the 12-1/4” section started out at 1.3sg and was increased stepwise to 1.48sg towards TD at 2324m TVD. No borehole stability problems occurred and the drilling performance was good. The flow rate was kept at a constant 4000lpm through the section.

For the 8-1/2” section the weight of the Glydril WBM was reduced to 1.22sg since it was going to drill through the reservoir section. No borehole stability problems occurred here either and the drilling performance was again very good, 29.5m/hr average ROP. The flow rate is unknown, but most likely somewhere between 3000-3500lpm.

For the 12-1/4” section in the slot recovery operation a Glycol/KCl/Polymer WBM was used with a set mud weight of 1.46sg. No borehole stability problems occurred and the drilling performance was good. Just before entering the reservoir section CaCO3 was added. The section reached TD at 2382m TVD without any problems, except for some tight hole when tripping out of the well. Back reaming was therefore performed.

The mud weight was decreased for the 8-1/2” section down to 1.2sg. A little lower than the same section in the original well path. Tight hole was experienced so the hole was back reamed to maintain borehole gauge. Flow rate was kept at around 2000lpm. TD was reached at 2675m TVD.

5.3.2.4. Formations

The formations drilled in the Heidrun North field differ slightly from the main Heidrun field. In the main Heidrun field Ror, Tilje and Åre formations comes directly after the Springar formation. In the Heidrun North field Garn, Not and an Ile formation comes directly after Springar and before Ror, Tilje and Åre. The lithostratigraphic table for the Heidrun North field can be seen in Table 11. As for the previous Heidrun well, there is little information on the contents of each formation.

Table 11 Complete lithostratigraphic summary of the 6507/8-D-3H well (Source: 6507/8-D-3H EOW report[6])

DISTANCE mRKB - mMSL: **22** m

FORMATION T	PROGNOSED			OBSERVED				
							DIFF. PROG	THICKNESS
	mMD	mTVD	mMSL	mMD	mTVD	mMSL	mTVD	mTVD
Kai Fm	1635.0	1478.0	1456.0	1640.0	1488.4	1466.4	10.4	357.2
Brygge Fm 3	2022.0	1840.0	1818.0	2020.0	1845.6	1823.6	5.6	65.6
Brygge Fm 2	2118.0	1914.0	1892.0	2100.0	1911.2	1889.2	-2.8	69.1
Tare Fm	2208.0	1981.0	1959.0	2187.0	1980.3	1958.3	-0.7	26.3
Tang Fm	2241.0	2005.0	1983.0	2222.0	2006.6	1984.6	1.6	55.1
Springar Fm	2305.0	2051.0	2029.0	2301.0	2061.7	2039.7	10.7	140.8
Garn	2551.0	2202.0	2180.0	2542.0	2202.5	2180.5	0.5	23.9
Not	2589.0	2222.0	2200.0	2592.0	2226.4	2204.4	4.4	1.4
Ile 6	2590.0	2223.0	2201.0	2595.0	2227.8	2205.8	4.8	4.8
Ile 5	2596.0	2226.0	2204.0	2604.0	2232.6	2210.6	6.6	5.1
Ile 4	2608.0	2233.0	2211.0	2613.5	2237.6	2215.6	4.6	9.6
Ile 3	2620.0	2240.0	2218.0	2630.5	2247.3	2225.3	7.3	5.9
Ile 2	2627.0	2244.0	2222.0	2640.5	2253.1	2231.1	9.1	2.4
Ile 1	2637.0	2250.0	2228.0	2644.5	2255.5	2233.5	5.5	1.3
Ror	2638.0	2251.0	2229.0	2646.5	2256.8	2234.8	5.8	13.5
Tilje 3.3	2701.0	2292.0	2270.0	2668.5	2270.3	2248.3	-21.7	8.8
Tilje 3.2	2718.0	2304.0	2282.0	2684.0	2279.2	2257.2	-24.8	15.0
Tilje 3.1	2735.0	2316.0	2294.0	2707.0	2294.2	2272.2	-21.8	4.4
Tilje 2.5	2740.0	2320.0	2298.0	2714.0	2298.5	2276.5	-21.5	5.1
Tilje 2.4	2747.0	2325.0	2303.0	2721.0	2303.6	2281.6	-21.4	8.1
Tilje 2.3	2756.0	2332.0	2310.0	2733.0	2311.8	2289.8	-20.2	8.8
Tilje 2.2	2764.0	2338.0	2316.0	2746.0	2320.6	2298.6	-17.4	5.5
Tilje 2.1	2768.0	2341.0	2319.0	2753.0	2326.1	2304.1	-14.9	9.5
Tilje 1.2	2778.0	2349.0	2327.0	2766.0	2335.6	2313.6	-13.4	4.4
Tilje 1.1	2782.0	2352.0	2330.0	2772.0	2340.0	2318.0	-12.0	10.2
Åre 2.13	2796.0	2363.0	2341.0	2786.0	2350.2	2328.2	-12.8	3.3
Åre 2.12	2801.0	2367.0	2345.0	2790.5	2353.5	2331.5	-13.5	3.7
Åre 2.11	2805.0	2370.0	2348.0	2795.5	2357.2	2335.2	-12.8	15.8
Åre 2.10	2822.0	2384.0	2362.0	2816.0	2373.0	2351.0	-11.0	6.1
Åre 2.9	2832.0	2392.0	2370.0	2824.0	2379.2	2357.2	-12.8	4.7
Åre 2.8	2840.0	2399.0	2377.0	2830.0	2383.9	2361.9	-15.1	12.4
Åre 2.7	2859.0	2415.0	2393.0	2845.0	2396.2	2374.2	-18.8	12.2
Åre 2.6	2868.0	2422.0	2400.0	2860.0	2408.4	2386.4	-13.6	13.6
Åre 2.5	2878.0	2431.0	2409.0	2876.0	2422.1	2400.1	-8.9	8.8
Åre 2.4	2885.0	2437.0	2415.0	2886.0	2430.8	2408.8	-6.2	
Åre 2.3	2891.0	2442.0	2420.0					
Åre 2.2	2895.0	2445.0	2423.0					
Åre 2.1	2900.0	2450.0	2428.0					
Åre 1.19	2903.0	2456.0	2434.0	2905.0	2447.9	2425.9	-8.1	
Åre 1.18	2912.0	2460.0	2438.0					
Fault	2911.0	2463.0	2441.0					
Åre 1.12	2911.0	2463.0	2441.0					
Åre 1.11		2474.0	2452.0					
Åre 1.10		2480.0	2458.0					
Åre 1.9		2481.0	2459.0					
Åre 1.8		2488.0	2466.0					
Åre 1.7		2497.0	2475.0					
Åre 1.6		2512.0	2490.0					
Åre 1.5	2983.0	2525.0	2503.0					
Åre 1.4		2554.0	2532.0					
Åre 1.3		2567.0	2545.0					
Åre 1.2		2587.0	2565.0					
Åre 1.1		2607.0	2585.0					
TD	3156.0	2675.0	2653.0					

5.4. The Titan Well

The 35/9-6 S Titan well was the second well to be drilled by RWE in 2010. It started almost immediately after the Zidane well was completed, and it was drilled with the Bredford Dolphin semi-submersible drilling rig. The 29th of September 2010 was when the drilling started and TD was reached at 3740m MD 58-1/2 days later. Figure 57 shows the position of the Titan well off the coast of Norway about 16 kilometers west of the Gjøa field with a water depth of 405m in the area.

The well is not close to the Zidane well, but the systems used to drill the well are identical. No similar problems with low ROP occurred in this well, and that is why it is of interest to look into the details and possibly find variables that might have caused this difference in drilling rate.

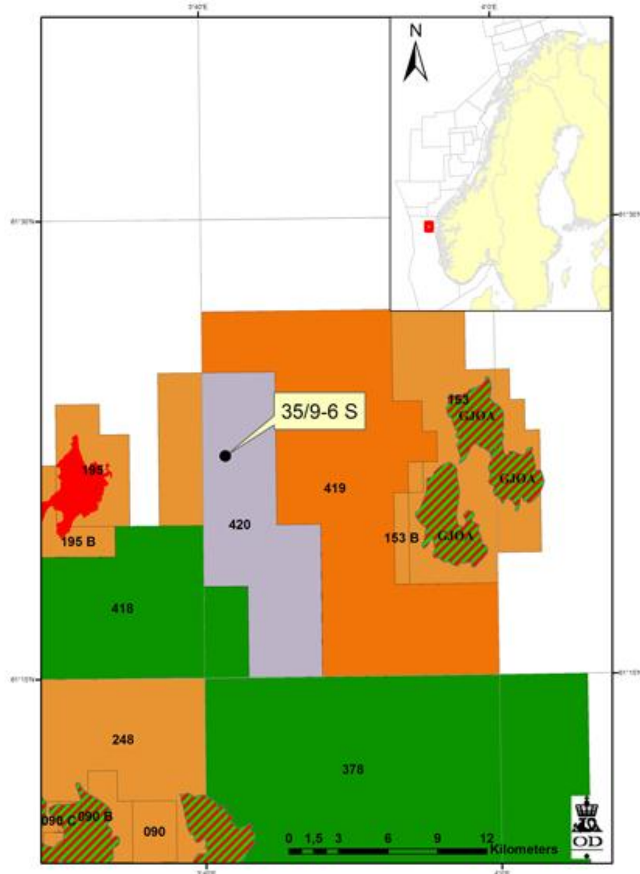


Figure 57 Map showing the position of the Titan well on the NCS (Source: www.npd.no)

Like Zidane, the Titan well also proved that hydrocarbons were present in the area. It was therefore plugged and abandoned for further assessment to determine the next step. The information presented in the following chapters have been gathered from the EOW report for Titan[7].

5.4.1. Bit Record

12 bit runs and 10 different bits were used to complete the Titan well. 4 of these bits were used to drill the top-hole sections, the 36", 26" and pilot hole. No significant problems occurred and the 26" section reached TD at 789m TVD.

Only 1 bit was used to complete the 17-1/2" section from 789m down to 1702m TVD. An insert rollercone bit was used and it performed with an average ROP of 17.5m/hr. The expected ROP was between 10-40m/hr. Due to cold mud and massive losses over the shakers a relatively low ROP was experienced between 789-1684m TVD. The performance was still within the expected range and the bit came out only slightly worn.

For the 12-1/4" section a 6 bladed PDC bit was used, the FXG65Rs. The bit drilled with an average ROP of 18m/hr down to 1870m MD in the Kyrre formation. At that point the BHA had to be pulled due to a failure in one of the tools. Despite a decent performance it was decided to change the bit to a 7 bladed PDC bit called FSF3751ZR. This was done because of some stick slip occurring during drilling, and it was hoped that a 7 bladed bit would avoid it. Stick slip did occur with this bit as well, but now bad weather and massive heave was a bigger concern. Overflow on the shakers was also a problem and certain drilling parameters had to be reduced. The average ROP with this bit was 15m/hr and it came out of hole slightly worn. TD of the section was reached in the Tryggvason formation at 3740m MD.

8-1/2" section was drilled with 2 bits and 4 bit runs. This was due to several coring runs. The first bit was the FXD65 PDC and it drilled with an average ROP of 8.6m/hr. It was changed to the FX64 PDC bit after the second coring run. This was because stick slip was experienced during drilling. The new bit however did not remove the stick slip problem, and tests performed showed that it was not just the bit that contributed to this. Stick slip occurred even with the bit off bottom. The FX64 bit performed with an average ROP of approximately 7.7m/hr and reached TD at 3517m MD. According to the EOW report no balling was experienced even with the matrix bodied bits.

5.4.2. Bottom Hole Assembly

From the top of the 17-1/2" section and down a complete BHA setup with MWD tools were used. In the 12-1/4" and 8-1/2" sections the GeoPilot® was also used to steer the wellbore. The GeoPilot® was eventually removed in the 8-1/2" section at a depth of 3266m MD, but the rest of the BHA was kept the same. No problems occurred due to the GeoPilot®.

As mentioned in the bit record a downhole tool failure occurred at 1870m MD and the tool had to be replaced with a backup. It was also proven in the 8-1/2" section that the BHA also was responsible for some of the stick slip occurring during drilling. No changes were made however. Apart from these issues no more problems occurred due to the BHA.

5.4.3. Mud and Hydraulics

WBM systems were used to drill the entire well. Seawater for the 36" hole and the 26" section, a WBM system with KCl and Gem for the 17-1/2" section, and the Performadril WBM system for the remaining 12-1/2" and 8-1/2" sections. For the first 3 sections the flow rate varied between 465.5-1723lpm. The flow rate was considered low, but nothing could be done to increase this due to losses over the shakers.

This did affect the ROP, but it did not create problems with hole cleaning. The mud weight started out at 1.03s.g in the 36" hole and was increased up to 1.19sg in the 17-1/2" section.

At the top of the 12-1/4" section the drilling fluid was changed over to the Performadril WBM and mud weight was increased to 1.25sg. It was kept constant at this weight through the entire section. Flow rate was kept between 2700-3500lpm. Again there was a problem with reduced flow and ROP due to overflow on the shakers. Even though the ROP was decreased it was still kept at a decent average of 17m/hr.

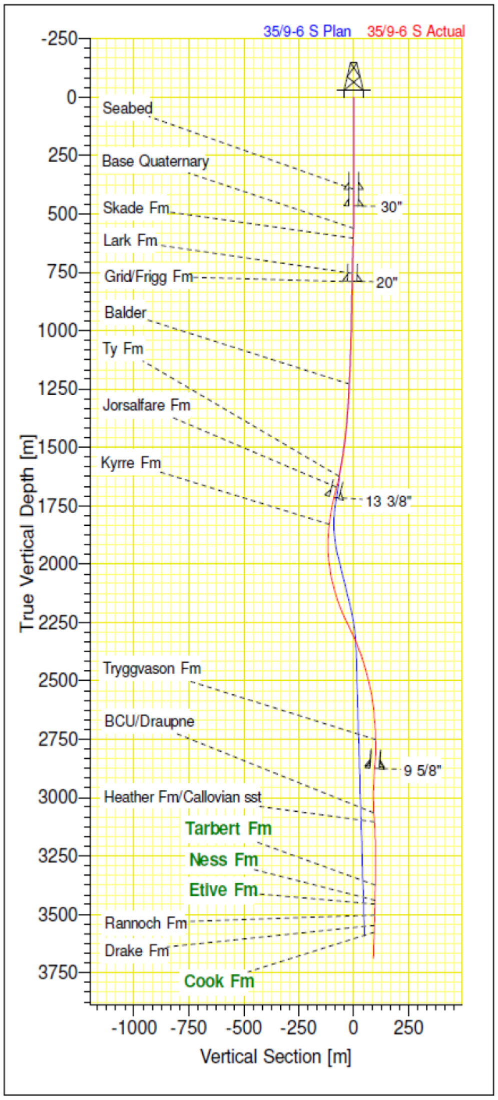


Figure 58 Planned well path(blue) versus actual well path(red) for the Titan well (Source: EOW report[7])

The same Performadril WBM was used for the 8-1/2" section, but the mud weight was increased to 1.6sg. Flow rate was kept between 1980-2500lpm. No problems with overflow at the shakers occurred in the section, and no indication of balling even though claystone formations were drilled. All in all it seems that there was very little to no problems with respect to the drilling mud itself and its composition.

5.4.4. Formations

Figure 58 on the right shows the depth in TVD for each formation top in the Titan well. It also shows the planned well path (blue) compared with the actual well path (red).

Hard limestone stringers were drilled in the Balder, Ty and Jorsalfare formations. A strong insert rollercone bit was used to drill at the time so the ROP suffered only slightly.

In the 12-1/4" section PDC bits were used, and even though claystone formations were drilled no bit balling occurred.

RWE did not perform a mineralogy analysis for the well since there were no problems with plastic shale formations. It is therefore not possible to determine if there was any smectite present in the formation layers.

The target formations were the bottom of the Heather formation, Ness and Etive formations, and finally the Cook formation. Mainly oil was discovered in all of the targets, and the preliminary estimates put the recoverability at around 2 to 10 million Sm3.

5.5. Summary

Without any practical experience from the field a generally wide and theoretical approach has been taken to identify possible problematic areas and generate well reasoned advice and recommendations. A wide range of technical papers regarding the plastic shale problem and possible solutions to it, and the detailed analysis of each selected well is therefore used as a basis for this discussion and summary.

The selection of each well has been obvious for some, and random for others. The three ConocoPhillips wells were chosen due to them being mentioned as offset wells for Zidane in the pre-drilling report. As for the two Heidrun wells the selection was somewhat random. It was clear very early in the process that it would be beneficial to look into wells from the Heidrun Field since the field itself is very close to Zidane. But the selection of each specific well was from a rough analysis of Halliburtons bit database and availability of information from the operator, Statoil. The last well, Titan, was selected since it was drilled by the same operator as Zidane, it used the same drilling rig, and it used the same type of drilling fluid. Most of the bit types used in both wells was also very similar.

5.5.1. Bit records

The amount of bits used to drill the different wells varies a lot. From a staggering 39 bits down to a near perfect 6 bits, almost 1 bit per section. There are several reasons for this spread in used bits; excessive wear, maximum time spent on bottom for rollercone bits, or just generally too low ROP. The latter being the most important for this subject. Low ROP in the 12-1/4" section was the main problem while drilling the Zidane well. 6-bladed, 7-bladed, steel bodied, matrix bodied and milled tooth rollercone bits were all put down hole to get a better ROP. No significant improvements were made, but some bits did perform better than others. The milled toothed rollercone bits performed most stable, whilst the 7-bladed PDC bit performed worst. As mentioned in the theory section for bit design when drilling low ROP/plastic shale its best to have as few blades as possible, as much JSA as possible, and aggressive cutters. Steel body is also preferable, because it`s easier for the cut formation to stick to a rough matrix body compared to a smooth steel body.

The oldest of the offset wells, 6507/7-1, only used rollercone bit, both insert and milled tooth. Amount of hours spent on bottom was also the reason for most of the bit changes made during the operation. Low ROP was experienced through most of the well, but no bit balling was seen. It is therefore very probable that plastic shale occurred in this well, especially since it is so close to Zidane. In the second offset well, the 6507/7-11S, there were also signs of plastic shale formations. Below 2448m TVD low

ROP became an issue with a 6-bladed steel body PDC bit down hole. The bit was not balled up, nor was it much worn. The next PDC bit however only drilled with an ROP of 1.05m/hr and was extremely worn when POOH. A rollercone bit was therefore put down hole, and an average ROP of 4-6m/hr was maintained. This is slightly higher than what was achieved with rollercone bits in the Zidane well, but it is still a very slow rate. Low ROP was a problem all the way down to TD of the section at 3365m MD. The third offset well, the 6507/7-12, was the only one of the three that did not experience any difficulties with regards to low ROP. The 12-1/4" section reached TD at 2508m MD with an average ROP of 40.7m/hr with a PDC bit. A 6-bladed matrix bodied aggressive bit was used. Only problem that occurred was due to poor cuttings removal and not bit related.

For the two Heidrun wells, 6507/7-A-18 and 6507/8-D-3H, no problems with low ROP occurred at all. Both PDC and rollercone bits were used, with the PDC bits outperforming the rollercone bits with more than twice the ROP. Indicating that PDC bits were the preferred bit type for drilling in these formations. It`s hard to determine the bit design for most of these since there are no datasheets available, but there is mentioned one bit from SDBS called FM2643 bit with 6 blades, steel body, and 9 vortex nozzles which performed with an average ROP of 45.6m/hr down to a depth of 2335m TVD. That is about 335m into the Springar formation, in which the ROP problems occurred in the Zidane well.

In the Titan well the same type of bits were used compared to Zidane. No low ROP problems occurred, and the same bit that first experienced low ROP in the 12-1/4" section of Zidane, FXG65R, now drilled with an average ROP of 18m/hr. Even a 7-bladed, steel bodied PDC bit performed with an average 15m/hr. The ROP was also reduced due to very bad weather, so the performance could have been even better in good weather conditions. There were some problems related to stick slip, but no plastic shale issues.

5.5.2. Bottom hole assembly

The bottom hole assembly might not be the most obvious cause of low ROP problems, but there are several factors affected by the type and size of equipment used. One of these factors is pressure drop, which in turn affect the stand pipe pressure. Logging tools and rotary steerable systems such as the GeoPilot® normally does not affect the stand pipe pressure, but mud driven downhole motors do. In other words if you have problems with a high SSP, it can become even worse if you include a mud motor in your BHA.

That was the case in the Zidane well, where a mud motor was used to increase RPM on the bit. The mud motor was only used for 53 meters before both the motor and the bit was replaced. ROP during this run was the lowest experienced during the entire operation, 1.73m/hr. The new ROP with a mill tooth rollercone bit and without the motor was now at 2.34m/hr. Some hard stringers were encountered which can be the cause of the somewhat low ROP for the rollercone bit.

A motor was also used in the 12-1/4” section of the offset well 6507/7-11S. At a depth of 2741m MD the ROP with a PDC bit was at an average 2-3m/hr. The bit was changed at this depth due to low ROP but the motor was kept in place. ROP with a new rollercone bit with the motor still in place was now 1.05m/hr. The BHA was POOH after 6 hours of drilling. A rollercone bit was used instead and the motor was removed. ROP with the new setup was an average of 4m/hr.

The third well which used a downhole motor was the 6507/8-D-3H Heidrun well. It was used in the 8-1/2” section of the slot recovery operation, and no low ROP problems were experienced. It was used together with an insert rollercone bit and reached an average ROP of 8m/hr in the reservoir section.

5.5.3. Mud and hydraulics

Table 12 below shows the most important information with respect to mud properties from each individual well. From the table several important issues can be pointed out. For instance, whenever a

Table 12 Table showing important details for each studied well with respect to mud and hydraulics

Well	Mud Type	Section	Mudweight(s.g)	BHA	Flow Rate(lpm)	ROP(m/hr)	Depth(m)
Zidane	Performadril	12-1/4"	1.55	GeoPilot	2700-3300	12->2.5	2200-3180 TVD
				Motor	2500-2850	1.73	3180-3233 TVD
				GeoPilot	2700-2750	2.34	3233-3289 TVD
	OBM		1.65	GeoPilot	2500-2640	17.3	3289-3947 TVD
6507/7-1	Gypsum&Polymer WBM	12-1/4"	1.55->1.69	Rotary	Unknown	1-5	2193-3820 MD
		8-1/2"	1.34->1.54	Rotary	Unknown	3	3820-4825 MD
6507/7-11S	KCl&Polymer WBM	12-1/4"	1.35->1.65	Motor	2550-2880	17.6->1.05->4	1995-3051 MD
			1.7	Rotary	2550	6->2	3051-3365 MD
		8-1/2"	1.2	Rotary	3550	6->11.6	3365-3749 MD
6507/7-12	KCl&Barasil WBM	12-1/4"	1.53-1.54	Rotary	2740-2820	58->20	1316-2508 TVD
6507/7-A-18	Aquadrill D	12-1/4"	1.48	Rotary	4450	26.2	1884-2363 TVD
		8-1/2"	1.18	Rotary	Unknown	14	2363-2654 TVD
6507/8-D-3H	Glydril WBM	1: 12-1/4"	1.3-1.48	Rotary	4000	45.6	1316-2335 TVD
		2:12-1/4"	1.46	Autotrak	4100	29	1200-2382 TVD
Titan	Performadril	12-1/4"	1.25	GeoPilot	2700-3500	17	1702-2925 TVD
		8-1/2"	1.6	GeoPilot	1980-2500	8.6->7.7	2925-3700 TVD

motor has been present in the BHA the ROP has been generally very low. In the Zidane well the ROP was 1.73m/hr, and in the 6507/7-11S offset well the ROP declined from 17.6m/hr down to 1.05m/hr before it climbed to 4m/hr with a rollercone bit. Since the motor creates an increased SPP the HSI down at the bit will decrease, meaning the force out from the nozzles will decrease. The information taken out from the reports therefore indicate that a lower HSI can affect the ROP negatively, at least to some extent.

The second important information is that the mud weight in all the wells with low ROP problems is generally higher than those without. It differs as much as 0.45sg on two of the wells, with the lowest difference being 0.07sg. The exception is the 6507/7-12 offset well, but that will be the next point.

Mud weight in the 6507/7-12 offset well in the 12-1/4" section varied between 1.53-1.54sg, which is almost the same as the Zidane and 6507/7-1 well. The main difference is the type of drilling fluid used, which for the 6507/7-12 offset well is a sodium silicate WBM. The performance in ROP is vastly different. At the end of the 12-1/4" section the ROP is more than twice as fast compared to the other two wells at the same depth. Sadly, after the 12-1/4" section was finished the drilling fluid was changed to an OBM, so it is not possible to see if the positive trend would have continued deeper into the formations. However, the TD of the 12-1/4" section is deeper than where the low ROP problems occurred in the Zidane well, and almost as deep as in the 6507/7-11S offset well. And the performance was still much better for the 6507/7-12 well even before the other wells experienced low ROP. This could be an indication that the mud properties of the Performadril WBM and the KCl&Polymer WBM are not suited for low ROP/ plastic shale drilling.

The final parameter to point out is the difference in flow rate for each well. In the Zidane well the flow rates were generally below 3000lpm, and declining as the depth increased. It`s unknown for the 6507/7-1 offset well, but as mentioned in the bit record summary rollercone bits were used. Also the well is 27 years old and better technology for drilling low ROP/ plastic shale has been developed since then.

The 6507/7-11S offset well also had a flow rate below 3000lpm through the problematic section. In addition it could be relevant to note that the mud weight was as high as 1.7sg with the WBM in the well. The Heidrun wells both had a flow rate above 4000lpm. That is more than a 1000lpm difference. Even though the flow rate for the 8-1/2" section in the 6507/7-A-18 offset well is unknown, it is still safe to assume that it would have been above 4000lpm as well. The flow rates in the Titan and 6507/7-12 offset well are pretty much identical to that of the Zidane well, but from the table one can see that the mud weight in the Titan well was 0.3sg lower and the offset well used a sodium silicate WBM.

As mentioned above the flow rate during drilling of the Zidane well was generally low. This resulted in an HSI value that didn't satisfy the recommended values for drilling in shale formations. The HSI value is dependent on the pressure drop over the bit, which in turn is dependent on the mud weight, flow rate and size of the bit nozzles. To calculate the bit pressure drop Equation 1 is used:

Equation 1 Pressure drop at the bit

$$Pressure\ Drop\ Bit = \frac{\dfrac{Mud\ Weight\ (sg) * Flow\ Rate(lpm)^2}{2671 * TFA(in^2)^2}}{100 * 14.5} = psi$$

In addition the wellbore area needs to be calculated by using Equation 2:

Equation 2 Wellbore area

$$Wellbore\ Area = \pi(\frac{Wellbore\ Diameter}{2})^2 = in^2$$

With the calculated pressure drop over the bit and wellbore area, Equation 3 can be used to obtain the final HSI value:

Equation 3 Hydraulic horsepower at the bit

$$HSI = \frac{\dfrac{Flow\ Rate\ (gpm) * Pressure\ Drop\ Bit(psi)}{1714(\frac{gpm * psi}{hp})}}{Wellbore\ Area\ (in^2)} = hp/in^2$$

As the values for flow rate and mud weight are constantly measured for each drilled meter no calculation is needed for them. The wellbore area calculation uses the wellbore diameter of the current section being drilled (i.e. 12-1/4" or 8-1/2"), whilst the TFA value is given by the bit provider which in this case is Halliburton.

The recommended HSI value for drilling in shale formations is 5hp/in^2 (ref. Halliburton Baroid), but from Figure 59 below it is clear that they were no way near that value. The average HSI through the low ROP section was closer to 2hp/in^2.

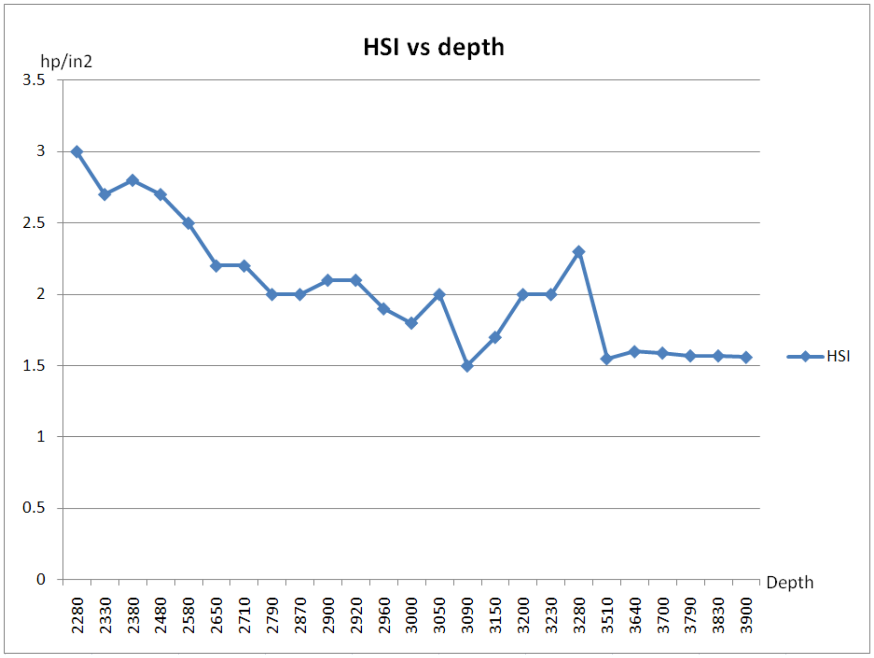


Figure 59 HSI versus depth in the Zidane well

Taking the same HSI values from Figure 59 and putting them in a graph versus the average ROP at the given depths during the low ROP section gives us Figure 60. From the figure a slowly increasing trend can be seen where the ROP is higher on average with a higher HSI value.

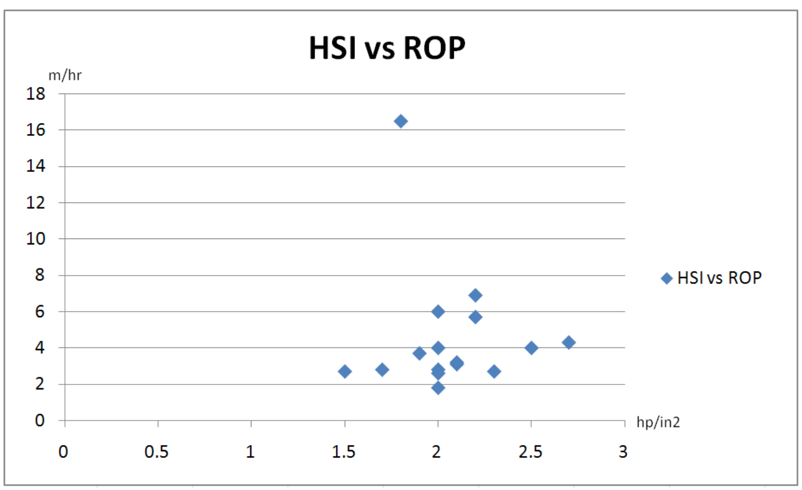


Figure 60 HSI vs. ROP in the low ROP section of the Zidane well

At 1.8hp/in^2 the ROP for one of the selected points is as higher than 16m/hr. This is most likely due to a different mineral composition in the formation compared to the other points. Figure 61 in the formation summary section shows that this point does not contain any smectite and is therefore dominated by other mineral types, in this case quarts[26]. The fact that the ROP is so vastly different does indicate that the required HSI is very dependent on the mineralogy of the formation being drilled.

All in all, several interesting differences that potentially could be a solution to the low ROP problem.

5.5.4. Formations

Because of the low ROP problems in the Zidane well, RWE Dea decided to do a thorough analysis of the cuttings to determine the formations mineralogy. This information is not available for the other wells, and the only comparison that can be done is between the formation layers and their depths. Table 13 shows this comparison. It also includes the TVD of each layers top from the rotary kelly bushing (RKB), and the LR behind some of the depths indicates an area with low ROP problems.

Table 13 Table showing formation layers sequential order for each studied well relative to the Zidane well

						Well Name						
Zidane		6507/7-1		6507/7-11S		6507/7-12		6507/7-A-18		6507/8-D-3H		Titan
Hordaland Gp	1909m	Hordaland Gp	1906mLR	Hordaland Gp	1852m	Hordaland Gp	1877m	Hordaland Gp	1847m	Hordaland Gp	1846m	Skade
Tare	2033m	Tare	2053m "	Tare	2067m	Tare	2099m	Tare	2020m	Tare	1980m	Lark
Tang	2084m	Tang	2102m "	Tang	2158m	Tang	2152m	Tang	2070m	Tang	2007m	Grid
Springar	2145mLR	Springar	2159m "	Springar	2184m	Springar	2196m	Springar	2112m	Springar	2062m	Frigg
Nise	2461mLR	Nise	2400m "	Nise	2225m	Nise	2377m	Ror	2310m	Garn	2203m	Balder
Kvitnos	2870mLR	Kvitnos	2824m "	Kvitnos	2316mLR	Kvitnos	2595m	Tilje	2395m	Not	2226m	Ty
Lysing	2941mLR	Lysing	2926m "	Lysing	2896mLR	Lysing	2857m	Åre	2525m	Ile	2228m	Jorsalfare
Lange	3001mLR	Lange	3000m "	Lange	2911mLR	Lange	2897m			Ror	2257m	Kyrre
Spekk	3712m	Lyr	3645m "	Lyr	3317mLR	Aptian	3670m			Tilje	2270m	Tryggvason
Melke	3735m	Spekk	3680m "	Spekk	3322mLR	Spekk	3909m			Åre	2350m	Draupne
Garn	4162m	Melke	3785m "	Melke	3344mLR							Heather
Not	4236m	Ile	4338m "	Garn	3454m							Tarbert
Ile	4254m	Ror	4478m "	Not	3472m							Ness
Ror	4314m	Tilje	4586m "	Ile	3493m							Etive
Tilje	4422m			Ror	3555m							Rannoch
				Tilje	3611m							Drake
				Åre								Cook

Formation Name

Depth = TVD RKB
LR = Low ROP

As expected it is the three offset wells that have the most similar setup in formation layers compared to Zidane. All of them contain the same formation layers, and the depths of each formation top are within a few hundred meters apart. The Heidrun wells are also very much the same all the way down to the Springar formation. Below the Springar formation, in the Heidrun fields, are the same formations that appear at the basement of Zidane and the offset wells. This deviation is known as a Base Cretaceous Unconformity, BCU. The low ROP problem in the Zidane well occurred in the middle of the Springar formation, whilst for the 6507/7-11S offset well it occurred in the Kvitnos formation. An overall low ROP was experienced through the entire 6507/7-1 offset well. None of the other wells had plastic shale related low ROP problems.

In Zidane the clay mineral smectite is present in considerable amounts through Springar and all the way down to the Melke formation. If this is the case for the offset wells is impossible to determine due to the lack of information. However, information acquired from Statoil regarding the Heidrun fields confirms that smectite is present together with other clay minerals such as kaolinite and illite[27]. The concentration of the smectite mineral group, in the Zidane well, varies between 51% and 27%. At some point, in a hundred meter thick interval, smectite is not present at all but the low ROP issue still persists. It is speculated that this could be due to other minerals such as quartz behaving in a plastic manner. The concentration of these minerals in the Heidrun fields is unknown. Figure 61 shows the ROP versus concentration of smectite in the problematic Zidane well. No apparent trend can be seen. Without the smectite mineral present the ROP was actually 16.5m/hr at one point and 2.5m/hr at another, indicating that the presence of smectite might not be a direct cause to the low ROP.

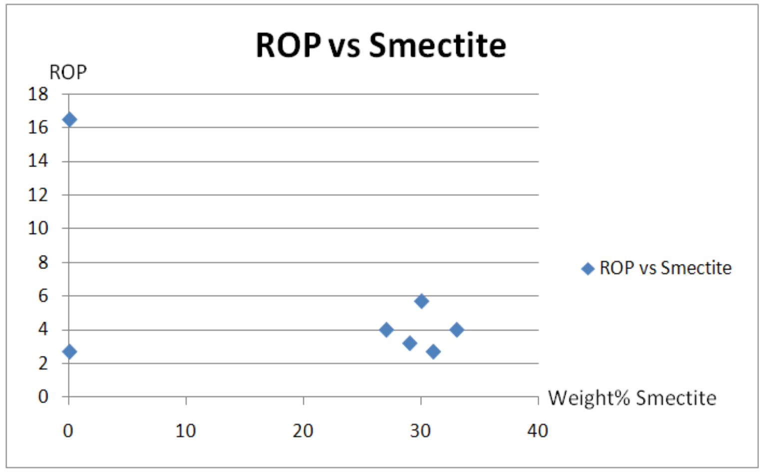


Figure 61 ROP versus Smectite in the low ROP section of the Zidane well

Even though there is a lack of information on the mineralogy of most of the wells, the formation layers are so similar that it is still very relevant to compare the different data obtained from the EOW reports. It should still be kept in mind when considering the following recommendations that variation in performance could be related to variations in mineralogy.

6. Conclusion

Based on the information from the case study summary, and the papers studied on the plastic shale and low ROP subject, the following points have been put together as suggestions for improvement:

- PDC Bits with few blades and steel body are preferred to decrease the chance of bit balling and maximize JSA. The steel body has a smoother surface compared to a matrix body, and in addition using steel allows for a larger JSA. Combine this with fewer blades and the JSA is increased even more.
- Aggressive cutters, possibly cutters with a positive backrake position, should be used when drilling plastic shales. The plastic shale formation is not in itself abrasive but very ductile. Using more aggressive cutters could therefore benefit the drilling rate. Precaution should be taken if there are hard stringers present as these can rapidly wear the bits cutters.
- Use bits with many and strategically placed nozzles. If bit balling does occur when drilling plastic shale formations, having more nozzles at the right positions will effectively keep the bit clean. Having vortex nozzles will help even more in keeping the bit un-balled.
- Avoid using downhole mud motors in the BHA, since the pressure drop over the motor can easily limit the HSI at the bit, and the increased RPM might not be beneficial if the formation is plastic. Based on the information obtained from the well reports using a motor has reduced the ROP by several meters per hour.
- Keep the mud weight as low as possible. This has been suggested by the Halliburton Baroid department, and the information listed in the table regarding mud and hydraulics supports this suggestion.
- Adjusting the casing program. By optimizing the casing program based on expected pore pressures it may be possible to reduce the mud weight without fracturing the formation below the previous casing shoe.
- Use a Managed Pressure Drilling system. This will allow the mud weight to be as low as the pore pressure of the formation, and can potentially have significant positive effect on the drilling rate in deep shale environments. Currently not possible to use on floating rigs, but new equipment that will allow this is currently under development.
- Optimize the flow rate. The HSI at the bit when using WBM should be higher than $4hp/in^2$, and is recommended to be above $5hp/in^2$ when drilling plastic shale. The HSI during the low ROP

problems in Zidane was only 2.5hp/in^2 HSI or less. If possible, and if the maximum SPP for the rig does not limit this, the flow rate should therefore be at least higher than 3hp/in^2.

- Sodium Silicate WBM should be considered when expecting plastic shale formations. It performed exceptionally well in the 6507/7-12 offset well, and it has been recommended by several professionals worldwide as a viable solution to the plastic shale problem.

It is important to note that many of these suggestions are based on parameters that are dependent on several different factors, and that the trends observed in the well case studies can be coincidental. Having that in mind, the indications are strong enough to be taken seriously for future well planning. Points such as the minimum HSI requirements when drilling in shale formations is even supported by very recent research done by Shell[28].

What next?

Further study should be performed to determine the HSI values for the offset and Heidrun wells, and compare these with the values from the Zidane well.

Several of the ideas from the papers mentioned in this thesis such as the negative backrake cutter bits, polished cutters, low-friction coating and electro-osmosis should also be further investigated to determine if these are valid solutions that can be applied to the field.

And finally, if possible, further lab testing should be performed to determine the actual cause of the low ROP problem.

7. Abbreviations

BCU	Base Cretaceous Unconformity
BHA	Bottom Hole Assembly
BUE	Built Up Edge
EOW	End Of Well
HSE	Health, Safety and Environment
HSI	Horsepower per Square Inch
HWDP	Heavy Weight Drill Pipe
ID	Inner Diameter
JSA	Junk Slot Area
LPM	Liters Per Minute
LR	Low ROP
MEG	Modified Extended Gage
MPD	Managed Pressure Drilling
NCS	Norwegian Continental Shelf
NPD	Norwegian Petroleum Directorate
OBM	Oil Based Mud
OD	Outer Diameter
PDC	Poly-crystalline Diamond Cutter
POOH	Pulled Out Of Hole
RKB	Rotary Kelly Bushing
ROP	Rate Of Penetration
RPM	Rotations Per Minute
RSS	Rotary Steerable System
SPP	Stand Pipe Pressure
TD	Total Depth
TFA	Total Flow Area
TVD	True Vertical Depth
WBM	Water Based Mud
WOB	Weight On Bit

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