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Sub-micron deformable polymer imparts stability improvement in offshore shale sections

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Abstract

In an offshore field, a formation is known for wellbore instability that frequently leads into wellbore failures associated with weak bedding planes. To counter these failures, caused by wellbore instability, which is mitigated by using high fluid densities to reduce sloughing, caving and tightness during trips. This use of high fluid densities can lead to instances of differential sticking, meaning that the fluid should be formulated with a suitable bridging package to mitigate the effects of drilling with an overbalanced pressure into highly depleted zones. Traditionally this approach for bridging involves sized blends of calcium carbonate and graphites.

This paper contains 2 case histories describing the use of a sub-micron deformable sealing polymer specifically designed to penetrate deep into the pore-throats and consequently seal small opening apertures such as shale micro-fractures in the sub-micron regime. The first case contains geo-mechanical modelling to determine the impact of increasing fluid densities from 11.1 to 12.7ppg. The sub-micron polymer was added to the fluid, imparting stability and minimizing fluid transmission into the shale micro-fractures resulting in the reduction in tripping time from 40 to 2.75 hours and no fluid losses were induced. The second application concerns another offshore well in the same field where the ECD requirements resulted in a similarly restrictive window and resulted in overbalance pressure that stuck pipe. This event prompted the use of the sub-micron deformable polymer enhance stability and well drilled successfully with minimal washout recorded on caliper logs and with no tightness on trips or casing run.

Introduction

Wellbore instability is one of the most important factors today when drilling safe, smart, economic wells. In recent years, the advancement of drilling technologies have included horizontal wells, ERDs, re-entries and multilateral wells which can each add challenges to the wellbore. At the same time, the mid-2010's oil-price crash prompted aggressive cost saving strategies brandishing a whole new focus for both Operators and service companies to find ways to maintain a stable wellbore[1]. As a result, well planning and design is focused on drilling and stimulating deviated and horizontal wellbores characterized by complex geological formations with layers of reactive or brittle shales, sections with abnormally pressured zones and tectonically active areas[2].

Wellbore Stability

Borehole instability issues result in what drillers commonly refer to as 'tight hole' or 'stuck pipe' incidents that can arise from a number of different but related root causes. The average cost of stability problems is in the range of 5-10% of the total cost of exploration and production of a well due to lost time and occasionally lost equipment. In the case of offshore drilling, the comparatively high cost and complexity of drilling operations demands an emphasis on avoiding lost time events due to wellbore instability[3] rather than fixing them afterwards.

Evaluation of stability of a formation is problematic for well planning for a number of reasons when trying to predict a rock's response to mechanical loading. The drill bit may be thousands of feet away and core samples are rarely taken above the reservoir for rock mechanics testing due to high cost and lost time from sampling. There may be large variations in formation stresses such as depleted sandstone, non-depleted shale layers and faults all in the same well which are not systematically measured. There are a number of mechanisms that contribute to the onset of instability including drilling fluid chemistry, fluid density, redistribution of stresses and temperature changes. No matter how complex a model is for characterizing the stresses in a formation, complete accuracy cannot be achieved due to these special issues for evaluating potential for instability. However, current models and field experience have led to guiding principles based on ideal assumptions that limit the risk of stuck pipe incidents[3].

Stresses, pore pressure and rock strength are widely regarded as the major factors governing wellbore stability and is the basis for a good approach to mechanical modeling[1]. The Mohr diagram is useful for characterizing stability based on these three major factors. In the model, rock strength is represented by a straight line (the Mohr Coulomb line) with two material constants, cohesion and friction angle. The mechanical state is represented by a circle, the Mohr circle, on the x-axis, the size and position of which is determined by stress, mud pressure and pore pressure. The higher the stress, the larger the circle, the higher the mud pressure the smaller the circle. The position of the circle on the x-axis is determined by pore pressure, where a higher pore pressure shifts the center of the circle closer to the Mohr Coulomb line, shown in Figure 1. Conditions resulting in the circle boundary tangenting the line indicate high risk for borehole instability[1]. The risk of mechanical hole collapse with respect to borehole stability is particularly high when the formation strength is low, when the failure angle is low (55° or lower) and the pore pressure is high. These conditions are regularly found in shale formations, which make the situation especially problematic in shale layers located directly above the reservoir[3]. Mud composition and chemistry play a unique role in remedying unstable conditions resulting from high pore pressure, low fracture gradients and reactive shales.

Under & Over Balance

The terms overbalanced and underbalanced drilling are used to describe conditions where the mud column pressure is higher or lower than the pore pressure in the formation respectively. Hard limestones and sandstones can support underbalanced drilling without caving due to their inherently high cohesion strength, whereas shales with comparatively low or complete lack of cohesion strength would not. Shales drilled in underbalanced conditions are prone to large spalling shale fragments sloughing into the wellbore which are difficult to remove and further increase hole gauge[1]. Drilling underbalanced in a formation with high cohesion strength can be done to increase rate of penetration significantly, however in the case of high permeability formations the risk of a kick is heightened. In any formation, regardless of cohesion strength, stability is reduced in underbalanced conditions. Drilling overbalanced is preferred for stability; however the upper limit is then guided by the formation fracture gradient[2].

Pressure Window

The traditional method of increasing mud weight alone to remedy wellbore instability phenomena is not always the best option. Microfractures are commonly found in brittle shale layers and increasing mud weight could instead lead to other issues such as lost mud[4]. Low permeability shales are susceptible to slow losses from pore pressure transmission which over time lead to a reduction in pressure differential between the formation and wellbore. If the section is not cased in time, wellbore instabilities arising would be similar to the caving and sloughing issues found when drilling underbalanced.

In drilling a well, fluid density, as well as equivalent circulating density, must be kept great enough to control formation fluids, but not so high as to induce a fracture. The safe mud weight window is hence defined as the pressure between the pressure at which a kick might occur and the pressure at which drilling fluid losses will be initiated[4]. In normally pressured zones, a sufficient margin of safety ensures an increased pressure window. However, in geo-pressured zones, the window between the fracture gradient and pore pressure will narrow significantly as the geo-pressuring increases. In highly geo-pressured formations, an additional margin of safety may be provided by the tensile strength of the rock. However, if natural fractures are present or the tensile strength is low it becomes extremely important to minimize circulating pressures and transient pressures in the annulus under these circumstances[5]. It is also possible to utilize certain specializes drilling fluid products in these areas to assist in stability control. The ability to predict formation and fracture pressures becomes important when planning mud weight, mud composition, equivalent circulating density (ECD) and casing programs to minimize stability risks[5].

Failure types and prevention

The major ways that stuck pipe and tight hole impact the cost of drilling are from lost time due to the consequent need to ream or sidetrack while drilling. Wellbore instability may also contribute to other problems later in the drilling process. Wireline logs can be difficult to read in sections where instabilities have occurred because log interpretation is based on the assumption of a gauge wellbore with a known diameter. Irregular borehole shape also leads to uncertainty when calculating the required cement volume for casing operations[3]. The main causes of tight hole/stuck pipe are hole collapse, Insufficient hole cleaning, differential sticking and deviation from ideal trajectory[3]. On the other end of the hole stability spectrum, lost circulation is encountered when a significant amount of fluid is lost to the formation due to induced fracture (by exceeding the fracture gradient) or losing mud to an existing fracture. Some of these failure mechanisms are outlined in more depth in the following sections.

Differential Sticking

Differential sticking is the only likely reason for stuck pipe in a permeable reservoir rock. When differentially stuck, the drilling tool is secured to the borehole wall as a result of a high differential pressure between the well and the formation and an overly thick filter cake[3], as shown in Figure 2. The mechanism of differential sticking described briefly is as follows. A portion of the drill string lies against the low side of a deviated hole. With rotation of the bottom hole assembly, lubrication from a thin film of mud ensures even pressure on all sides of the pipe. When rotation is stopped, the portion of the pipe in contact with the filter cake is isolated from the mud column and the differential pressure between the top and bottom of the pipe causes drag when an attempt is made to pull the pipe.

If the resulting drag exceeds the pulling power of the rig, the pipe is differentially stuck[5]. Sticking may occur at any point along the drillstring that bears against a permeable formation with a filter cake. The chances of sticking are greater in the presence of a thick filter cake, as the contact area is greatly increased when the drillstring is embedded in a thick, porous surface layer[5]. Drilling high angle holes from offshore platforms creates an increased occurrence of the conditions for differential sticking. In these circumstances, the weight of the collar against the wellbore and the erosion of rock beneath the collars may both be high enough to prevent the formation of a conventional filter cake. When coupled with an insufficient annular velocity, enough to transfer cuttings out of the hole, a cuttings bed will accumulate underneath the collars and become incorporated into the filter cake. This resulting poor quality filter cake, built with compressible and non-compressible solids forms a poor and permeable barrier between wellbore fluid and formation and thus can result in incidents of differential sticking[5].

Minimizing differential sticking incidents can be achieved by choosing different collar types and lengths, but also by optimizing drilling fluid components and properties. Pull out force has been shown to increase with high differential pressure, contact area, filter cake thickness and coefficient of friction. Differential pressure may be kept low by keeping the mud density as low as possible, the lower limit is dictated by the pore pressure and collapse gradient. Oil-based muds are preferred due to the inherently low coefficient of friction and formation on an internal, rather than external, filtercake compared to water based muds, although there are many available water based products that work to minimize coefficients of friction. To minimize contact area and cake thickness, cake permeability should be kept low and drill solids should be rigorously reduced by the use of highly efficient solids control equipment[5]. Drilling fluid additives that work by bridging and then effectively sealing the formation and filter cake by means of submicron deformable particles are critical for this process as will be described in later sections.

Hole Collapse

Hole collapse happens when the near-wellbore formation fails mechanically either by shear failure or tensile failure. Hole collapse can either result in an increased or decreased wellbore size depending on the nature of the failure. Increased borehole size results from the shear failure of brittle shale when a loss of pressure differential at the near-wellbore formation causes caving or spalling of shale fragments. A decrease in borehole size occurs in weak, plastic shales, sandstones, and salt or chalk formations. The reduction in hole size has been traditionally attributed to the swelling of reactive clays in contact with drilling fluid. Lack of sufficient pressure in the wellbore for while drilling in soft, plastic shale can result in a deformation of the wellbore and reduce hole size. This circumstance may require repeated reaming and could potentially lead to lost drill pipe, bit balling, and solids accumulation[3]. When shale spalling occurs in brittle shales from drilling below the pore pressure gradient, the free rock surface generated from this circumstance is exposed to the exact same conditions and thus the effect is not self-stabilizing. Drilling underbalanced is also risky since, in permeable zones a kick could result from the lack of hydrostatic pressure balance[3]. Traditionally the best method of preventing hole collapse is to increase mud weight[3].

Exceeding fracture gradient

In order to minimize influx of fluids, it is considered necessary to keep the mud weight above the pore pressure gradient. In order to prevent the loss of mud into fractures, the optimal approach is to keep mud weight or equivalent circulating density below the fracture gradient[3]. The fracture gradient is the pressure required to induce fractures in a rock at a given depth. A fracture is induced when the difference between the mud column pressure and the formation pore pressure exceeds both the tensile strength of the formation and the compressive stresses surrounding the borehole[5]. Significantly fracturing the wellbore leads to lost circulation which is problematic because drilling fluid is expensive and there is a limit to the amount available on the rig. Mud loss can also lead to temporary pressure drop in the well and may lead to a kick or blowout event. In some cases fractures may initiate but stress conditions may not lead to fracture growth. In previously unfractured wells, significant mud losses may not occur until the formation is stressed to the point of fracture growth[3]. Fracture growth commences when the pressure exceeds the minimum principle stress, plus an additional term depending on the conditions for fracture growth at the tip of the fracture. This additional term is decided based on operational experience in the field[3]. Usually a fracture is induced just below the casing shoe where the difference between fracture pressure and mud pressure is the greatest. This is especially common when the mud density is increased to control a kick in the lower part of the hole and the fracture pressure gradient is exceeded higher in the hole at the shoe. In this case, a common approach is to strengthen the wellbore by pumping pills of lost circulation materials downhole thereby filling the fractures with material that will widen the fracture and increase hoop stress in the formation[5]. When a natural fracture is encountered, it is possible to determine the size of the fracture by closely correlating mud loss and rheology data over time during circulation[6]. In this case, the optimal lost circulation material package may be designed based on particle size distribution and strength of material.

Formation Types and Associated Stresses

In terms of strength, rock can be roughly classified into two categories; high cohesion strength (hard limestones, sandstones) and low to zero cohesion strength (shales)[1]. During drilling, the strength of a rock relative to the near-wellbore stresses will remain mechanically stable or undergo permanent deformation. Predicting wellbore stability from a mechanical perspective requires rock strength parameters (cohesion), in situ stress, geometry and orientation of the borehole, and shear failure of the rock. The key parameters of rock strength include unconfined compressive strength, tensile strength, cohesion and the coefficient of internal friction. Core samples from the formation are generally used to characterize these aspects of the rock along with empirical correlations based on log data[2]. Many reservoirs are characterized by anisotropic rock fabric which is important when considering rock strength in relation to orientation of the wellbore. In general, rock strengths measured parallel and perpendicular to the bedding planes in anisotropic material are stronger than orientations in between. In deviated, unconventional wells it becomes very likely to intersect the formation at many angles relative to bedding planes and thus rock strength is significantly reduced. This leads to an increased incidence of fractures induced at the near wellbore[2]. *In situ* stresses are represented by three principle stresses; vertical stress which is the overburden stress from gravitational loading from overlying rock, minimum horizontal stress and maximum horizontal stress which are important in anisotropic rock fabric. Exceeding the minimal horizontal stress has a direct influence on fracture initiation and propagation[2]. Minimum horizontal stress can be determined by pumping fluid into a formation to induce a fracture and observing the pressure at which the fracture closes. The closure pressure is equal to the minimum horizontal stress[2]. The stable range of horizontal stresses are narrowed significantly as angle of inclination increases, particularly from 30° to 60°. In anisotropic rock fabric, the stable range of horizontal stresses is reduced significantly and the chance of fracture initiation and growth becomes high[3].

Pore Pressure Transmission and Shale

Any mechanism that increases the pore pressure in the well vicinity will result in a decrease in stability. Two main processes modify pore pressure, hydraulic force from overbalanced conditions and chemical gradient which is guided by salinity differences between formation and wellbore[1]. Fluid movement from well to rock, whether driven by hydraulic or chemical force has a tendency to increase pore pressure in the near-wellbore region. Pore pressure is therefore the main driving force of instability and the ability of a mud to mitigate flow conditions at the face of the wellbore becomes a key factor in fluid design. In overbalanced conditions when hydraulic force exerts pressure and causes fluid flow towards the formation, a good drilling fluid will create a hydraulic barrier on the formation face and utilize proper salinity to ensure osmotic drive in the reverse direction[1].

Shales act as a semi-permeable membrane and depending on the chemical activity (salinity) difference between formation fluid and wellbore fluid, osmotic water flow occurs from the fluid with higher water activity to the fluid with lower water activity[1]. Oil based muds are preferred to water based muds due to the reduced tendency to leak fluid into low permeable formations and the water phase of these muds are kept at sufficiently low water activity to further drive osmotic flow from formation to wellbore[5]. Oil based muds also act as a semi-permeable membrane by preventing ions associated with salts from moving between the water phase of the mud and the formation[2]. Adding salt to the drilling fluid so that the water activity is lower than the formation water sets up an osmotic potential that will tend to drive water out of the shale and effectively reduces pore pressure, enhancing stability. It is well established that shale surface allows the passing of not only water but also salt ions into the bedding planes and thus must be regarded as a 'leaky' semi-permeable membrane. Due to the 'leaky' nature of the shale surface, the pore pressure transmission reduction by means of osmotic gradient alone is a temporary effect[3]. Eventually water activity between formation fluid and the drilling fluid reaches a state of equilibrium and the pore pressure infiltration is directed by hydraulic force.

For permeable formations such as sandstone, creating impermeable conditions at the face of the wellbore by means of a thin efficient filter cake is necessary to stabilize the well[3]. Both permeable and impermeable conditions benefit from the use of deformable sealing materials that reduce permeability further and by increasing efficiency of the semi-permeable membrane established at the wellbore, thereby directing osmotic flow from formation to wellbore.

Product Mechanism

As stated previously, differential sticking typically occurs when high contact forces caused by low formation pressures, high wellbore pressures or both, are exerted over a sufficiently large area of the drillstring. The bottomhole assembly is held in the cake by a difference of pressures between the hydrostatic pressure of the mud and the pore pressure around the surface of the wellbore. When a low permeability internal cake is formed, the pressure differential between the hydrostatic pressure of the mud and the external filter cake is reduced. The differential pressure between the mud column and formation is preserved which is necessary to prevent spalling shale or hole collapse. Due to the fine size and viscoelastic nature of the particles, the micronized deformable polymer has the ability to create a low permeability internal filter cake which helps to reduce the incidence of differential sticking.

The ability of the micronized deformable polymer to form an internal filter cake has been proven in a laboratory setting. In the study, two 30 minute dynamic filtration tests are done on low porosity ceramic discs (3-20µ), one with a standard water based mud and the same mud with deformable polymer included. Fluid loss values are plotted over square root time to observe the nature of the filter cake. In a dynamic fluid loss test, a filter cake builds initially and is relatively static in thickness over the course of the 30-minute test. In the base fluid, as expected, filtration values over square root time are increased linearly after the initial external filter cake forms. In the fluid containing submicron deformable polymer however, filtrations over square root time deviate from linearity and the rate of filtrate decreases over time. An example of this effect is shown in Figure 3. This is an indication that an internal filter cake is being built within the disc as particles are being deposited over time thus slowing the filtration rate.

Based on the assumption of the formation of an internal filter cake, using measured fluid loss values, and a modification of Darcy's Law test results using deformable submicron polymer in a fluid can be compared to base results to calculate pressure differences between at the interface between the fluid and filter cake, the interface between the filter cake and ceramic disk and the back pressured face of the filtercake. As can be seen in Figure 1 fluid samples containing submicron deformable particles maintain a high pressure differential at the interface between the disc and filter cake but there is a reduced pressure drop within the filter cake when compare to the base fluid. This is an ideal scenario for mitigating the incidence of differential sticking during drilling.

Case History 1

The well in case history #1 was planned as a dual lateral oil well targeting the sandstone reservoir and was designed to be completed as a dual lateral with 6,000' of reservoir contact. The particulars were L0:+/- 10,351' MD/ 6,480' TVD & L1: +/- 10,738' / 6,492'TVD. After drilling the intermediate 12 ¼” interval using 83 pcf inhibited WBM from 5,556’ to 5,752’ with closely monitored mud parameters and proper bridging strategy, no losses were observed.
At 5,752’ the WBM was displaced to flat rheology oil based fluid 83 pcf to drill to the section TD at 7,500’.

The section was planned to be drilled as build up and lateral interval with an azimuth of 200-220 deg, which places it in a transition zone between the maximum and minimum stress.
A geo-mechanical study was carried out to identify the ideal mud weight window to be utilized based on modeling the offset data, rock characteristics and stress direction.

In reviewing the offset data, some wellbore failures associated with weak bedding planes were identified. A bridging strategy was designed, based on the range of data available, to be added to the fluid from the start of drilling the section to help to prevent a repeat of the weak bedding plane failures at high over balance conditions. The bridging additives, including the deformable sealing polymer, would also help to reduce the tendency for differential sticking when encountering high over balance pressures.

The interval was started by drilling with 83 pcf OBM with an option to increase to 90 pcf to avoid any caving across shale intervals with the pressure window as shown in Figure 4. The target was extended from 7,500’ to 8,995’ resulting in drilling 1,500’ further into the lateral. After drilling to TD whilst maintaining 83 pcf without issues, the hole was swept clean with standard practice tandem low viscosity followed by high density pills.. When starting to pull out of the hole, tight spots were observed after the first stand, coupled with increases in torque and pressure and an over-pull of 40K indicative of the hole packing off.

These signs indicated wellbore instability across the shale & sand formation. The decision was taken to increase the the mud weight, in 2 pcf increments from 83 to 95pcf. Figure 5 shows shale cuttings at 90pcf, mostly reamed Shale with 30% sloughing due to the need of more hydrostatic pressure. Figure 6 shows the cuttings at 93 pcf, larger cuttings than at 90 pcf indicating more severe sloughing. Figure 7 shows a clear increase of the Platy shale that has resulted from the continuing invasion into the wellbore and ongoing wellbore instability. As a result of these challenges, tripping out to the casing shoe at 5,556’, took 40.5hrs excluding circulation and flow check time.

Discussions between the technical experts from operator, fluids and geomechanics disciplines jointly analyzed the observations made during the trip and the sequence of cuttings images.
The solution to the wellbore instability of increasing density and pressure lead to an increase in the fluid invasion that further led to having a Platy shale sloughing from the week bedding planes as seen in Figure 7.
The final recommendation was to increase the addition of the sub-micron deformable polymer to enhance the bridging effectiveness and strengthen the semi-permeable membrane of the fluid under the higher than initially planned for overbalance conditions.
After running pilot tests to demonstrate that the increased addition of the polymer had no impact on the rheology profile of the fluid the additional material was added to the active system and operations recommenced to ream to bottom. Only 2 tight sports were observed at 7,272’ & 8,316’ before tagging bottom and circulating 3 complete system circulations. During this operation maintenance additions of the polymer were continued. Tripping out of the hole was trouble free, with no tight spots in only 2.75 hours. The cuttings from the reaming trip at 95 pcf are shown in Figure 8 and are in stark contrast to the previous images in Figures 5, 6 & 7. Table 1 shows a comparison of the fluid properties before and after the polymers addition. The yield point remains stable and other parameters show little if any variation. The HTHP shows an improvement of over 22% and the PPT value decreased by 37%, confirming the premise of reduction of fluid invasion into the wellbore.

Case History 2

The well in case history #2 is another offshore dual lateral with each lateral penetrating 4,000 ft into the sandstone reservoir.
The 8 ½” section was drilled utilizing 72 pcf flat rheology mud treated with 40 ppb of granular calcium carbonate and graphite bridging materials. Starting from 11,512 ft, increasing drag and over pull at connections was observed in combination with the shakers having an increased load of cuttings with every sweep. The decision was made to increase mud weight to 74 pcf to improve hole stability. While drilling, the string became mechanically stuck at 11,622ft and was freed by jarring. After continuing to drill, with 74 pcf, while monitoring the hole condition and tight hole during connections the drill string again became stuck at the section TD of 14,208 ft due to packing-off. Based on the issues getting to TD, a geo-mechanical analysis was carried out which identified that the lateral is laid on the border of minimum horizontal stress. This requires higher mud weight, up to 78 pcf, with proper bridging system to strengthen the formation and minimize pressure transmission through weak bedding planes in order to avoid challenges such as hole pack-off and becoming differentially stuck. The drilling direction stress is shown in Figure 9.
For the side-track, the bridging strategy was enhanced with the addition of the sub-micron deformable sealing polymer to minimize pressure transmission and reduce the risk of differential sticking due to over balance pressures while drilling with an increased fluid density.
After starting to drill the sidetrack 8 ½” hole utilizing 78 pcf Flat rheology mud loaded with 10 ppb graphites, 20 ppb granular and 8 ppb flakey calcium carbonate in combination with 1% by volume of the deformable sealing polymer.
With this bridging package the section was drilled smoothly to 12,289ft. and a tight spot was experienced during a wiper trip leading to an increase in mud weight to 80 pcf and a further 2 pcf increase after reaching TD. After cleaning the hole and spotting a casing pill, the string was pulled out freely to surface and the 7” liner was run and landed smoothly on bottom without any tight spots. The caliper log of the initial well and the side-track is shown in Figure 10 and the contrast is starkly seen between the original and side-track with washout to 12.335” of due to formation break-outs and wellbore instability due to mud invasion.

Conclusions

In Case History #1, the addition of the micronized deformable sealing polymer stabilized the shale and resulted in tripping time being dramatically by reduced from 40.5 to 2.75 hours thanks to the elimination of tight spots. The addition had no discernable effect on the fluid rheology or other mud parameters to demonstrate its compatibility with different fluid systems.
In Case History #2, the section was delivered smoothly by deploying the micronized deformable sealing polymer that strengthened the formation and prevented break-outs. Wash-out was significantly decreased by reducing fluids invasion and supporting the weak formation that benefitted drilling performance. The quality of the filter cake was improved which led to a tightening of the PPT values (Table 1). It was demonstrated in this second case history, by monitoring Mud parameters & drilling parameters, that adding the sub-micron deformable polymer no effect of the profile of the flat rheology fluid.

Acknowledgments

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Nomenclature

BHA = *Bottomhole assembly*
ECD =*Equivalent Circulating Density*
ESD =*Equivalent Static Density*
LCM =*Lost Circulation Materials*
WBM =*Water Based Mud*
OBM =*Oil Based Mud*
GPM =*Gallons Per Minute*
PPB =*Pounds Per Barrel*
PCF =*Pounds Per Cubic Foot*
BBL =*Barrels*
ROP =*Rate of Penetration*
PPT =*Particle Plugging Test*
PSI =*Pounds Per Square Inch*
OBSS =*Optimized Bridging and Sealing System*

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Figures and Tables

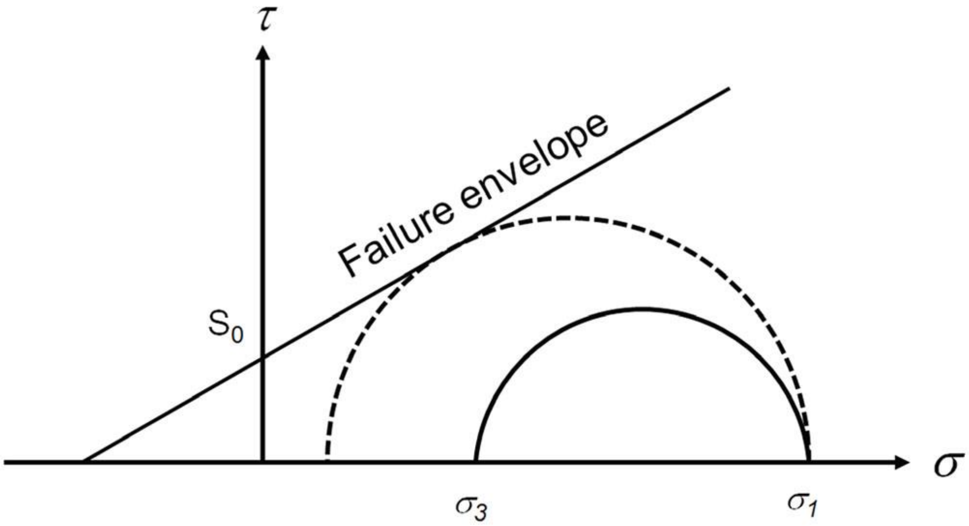

Figure 1 Mohr Columb diagram

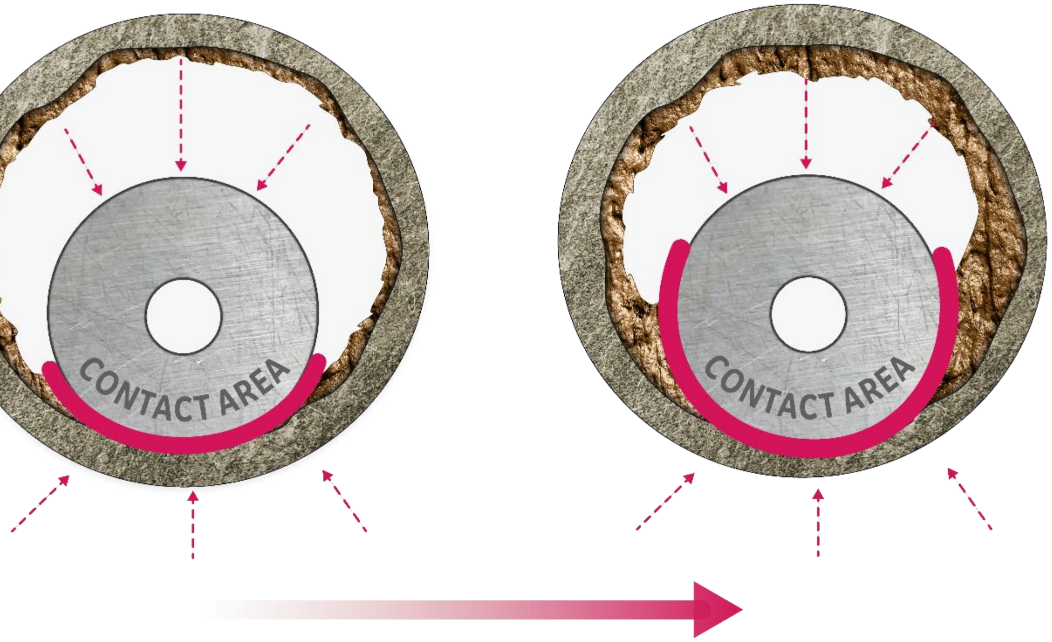

Figure 2 Schematic showing poor quality filter cake increasing contact area

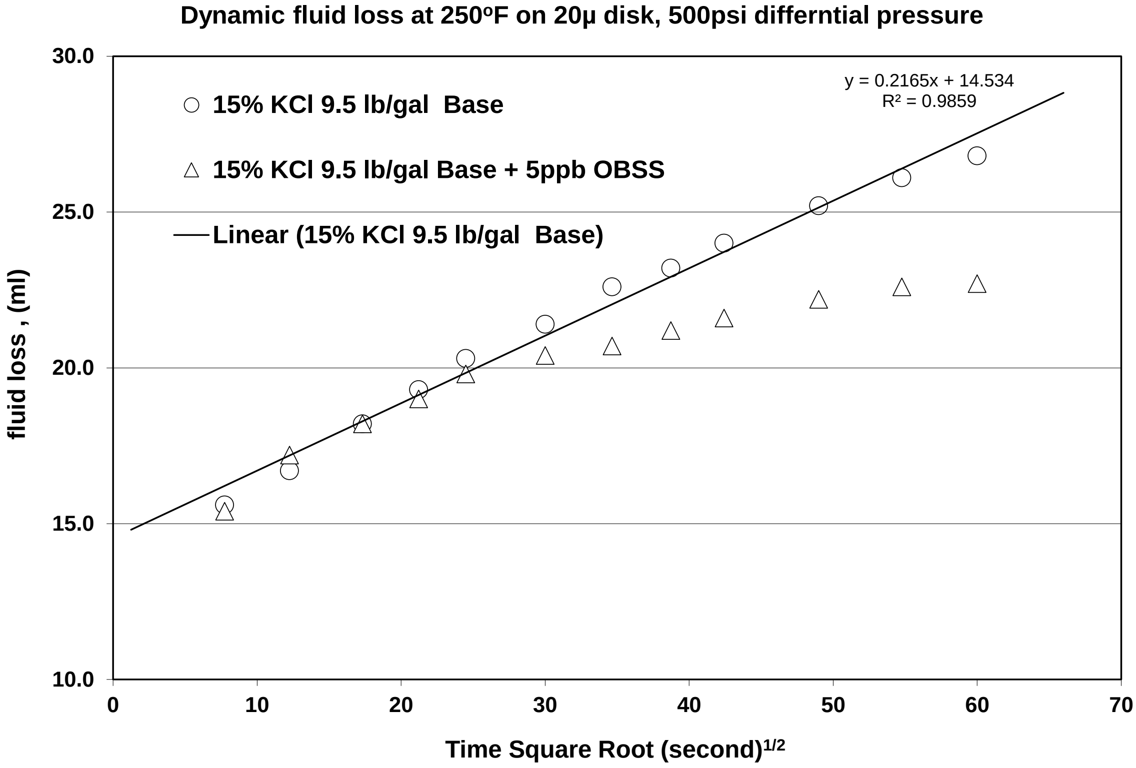

Figure 3 Dynamic Fluid Loss over square root of time for 15% KCl 9.5 lb/gal WBM with, and without sub-micron deformable polymer

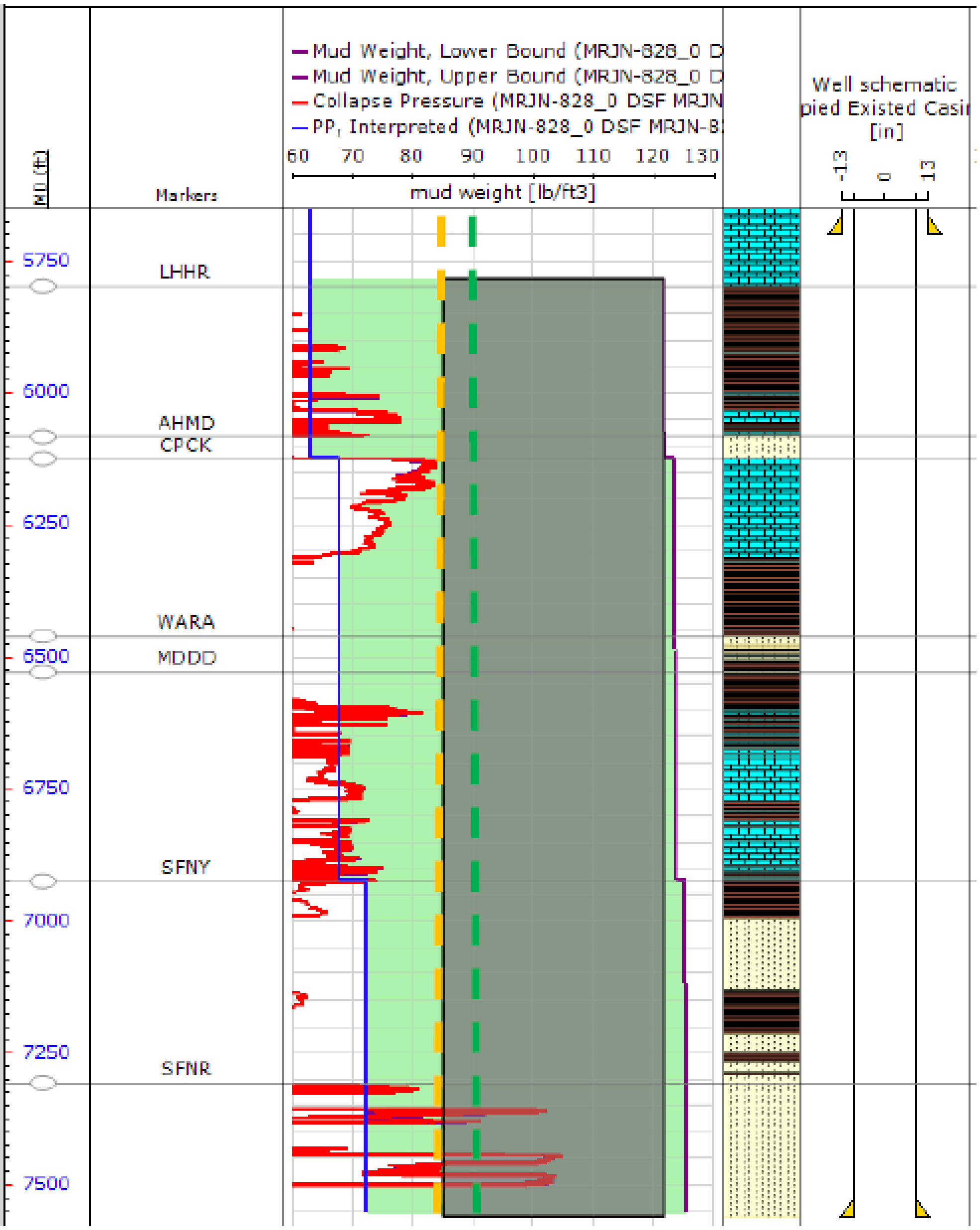

Figure 4 Case History #1 Formations and pressures

Figure 5 Case History #1 Cuttings from 90 pcf fluid

Figure 6 Case History #1 Cuttings from 93 pcf fluid

Figure 7 Case History #1 Cuttings from 95 pcf fluid

Parameter	**Initial Drilling Fluid**	**Fluid with sub-micron deformable polymer**
Mud weight, pcf	95	95
Viscosity, spq	76	78
PV	33	34
YP	23	23
Gel Strength	11/14/17	12/15/18
6 rpm	11	12
HTHP, cc	1.8	1.4
PPT Spurt/Total	0.6/5.4	0.0/3.4

Table 1 Fluid properties pre & post-addition of the sub-micron deformable polymer

Figure 8 Case History #1 Cuttings at 95 pcf after addition of sub-micron deformable polymer

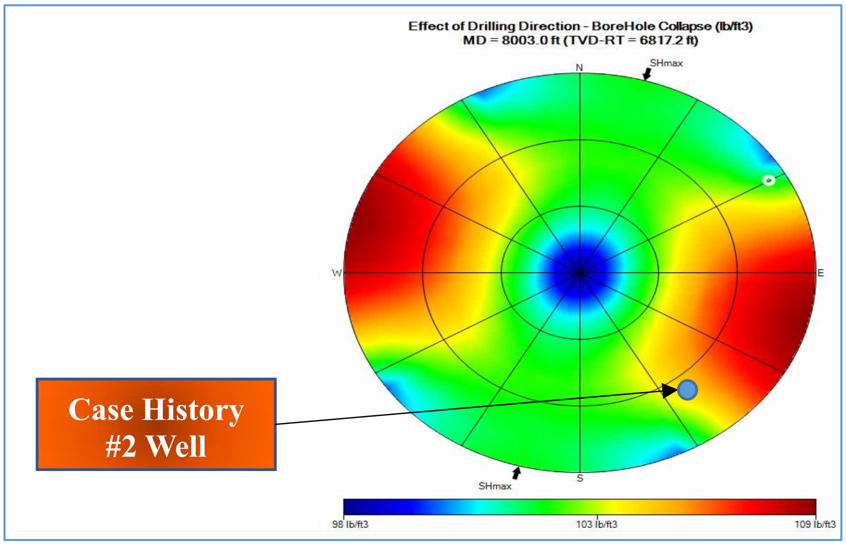

Figure 9 Case History #2 Drilling Stress Direction

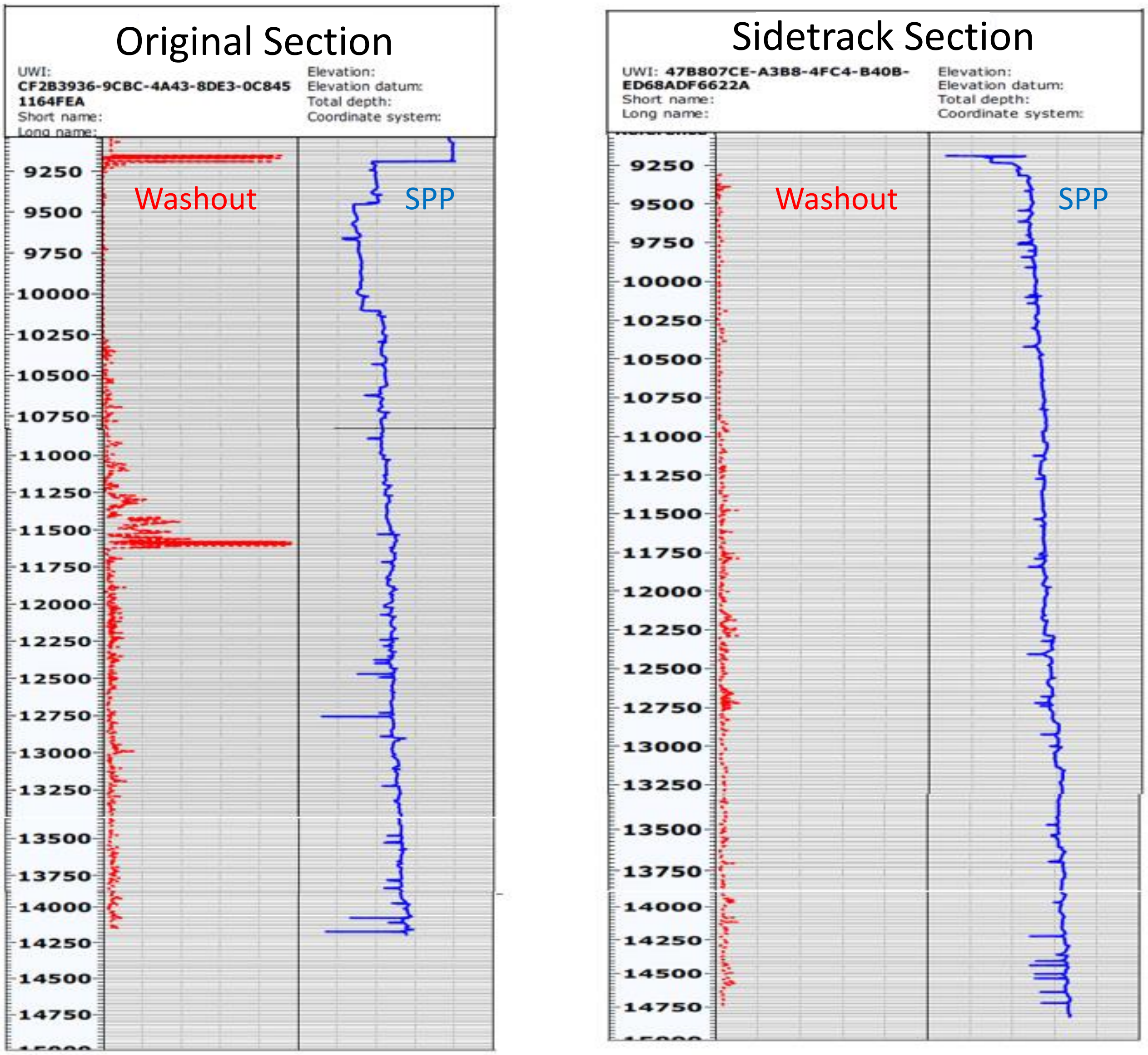

Figure 10 Case History 2 Original and Sidetrack Caliper logs showing washout