

High Salinity, Low Activity Oil Mud Improves Performance in Near Salt Drilling

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Abstract

Using controlled water activity, oil-based fluid in drilling operations historically has optimized drilling performance. In most drilling environments, activity control using calcium chloride brine internal phase of 250,000 ppm to 300,000 ppm provides the needed activity to balance or overbalance formation water demand. This results in a stable wellbore with reasonable mud treatments. Operators are recognizing that special situations occur where the typical water activities are inadequate and much lower activities derived from high salt concentrations are required. Drilling shale formations in close proximity to salt is such a special situation.

Estimation of the required water phase salinity when drilling shale containing crystalline salt is difficult. Although improved methods for determining activity under surface conditions are available, measurements on formation cuttings and sidewall cores will be subject to error due to a number of factors. This creates the concern that the drilling fluid activity can be too low and result in wellbore instability. Testing under downhole conditions of a shallow Gulf of Mexico preserved shale core having a high activity shows that low activity oil-based fluid does not contribute to wellbore instability. Mathematical models used in wellbore stability determinations also show that low activity can improve wellbore stability over a broad range of conditions.

Experience with directional wells (>15,000-ft MD) in the Cote Blanche Bay field utilizing a low activity oil-based fluid confirms that increasing the internal water phase salinity improves wellbore stability and reduces wellbore enlargement. A well drilled with typical water phase salinity in the 300,000 ppm is compared to a more recent well drilled with 380,000 ppm water phase salinity. The well with higher salinity has reduced washout using lower mud densities with reduced drilling problems. Shale pore pressure estimation confirms the similarities between the wells and caliper logs from the wells documents the improved drilling results.

Introduction

Most drilling operations with oil-based drilling fluids use a fluid containing emulsified calcium chloride brine as an internal phase. The salinity of the internal phase is usually specified and controlled within that range.

The salinity specification is many times developed without considering well or subsurface conditions. Recent experience

in drilling near salt with oil mud has proven that this approach can result in well bore stability problems.

Solving this problem required a re-examination of the theories used to estimate salinity requirements. This review resulted in recommendations for an increased salinity when drilling formations near salt.

The result of implementing this recommendation was improved wellbore stability, reduced trouble costs, and better caliper logs.

Salinity Control in Non-Aqueous Fluids

The principal of activity control in oil based and other non-aqueous fluids was first proposed by Chenevert¹ to provide an optimal environment for wellbore stability by eliminating shale hydration.

A useful definition of activity control is a measure of the escaping tendency of water from the fluid or the shale. The application of activity control in typical drilling operations uses an emulsified internal brine phase of an activity equal to or lower than the activity of the formation to be drilled.

The predominant method of controlling the internal phase activity is to use calcium chloride brine. Estimating the fluid activity is done by titrating the calcium and chloride ions in the fluid, measuring the water content using a retort, and calculating the water phase salinity. This water phase salinity is then related to an equivalent activity². A more detailed discussion of the principal of aqueous activity control can be found in drilling and drilling fluids texts^{3,4}.

Aqueous Activity Determination of Cuttings

Historically, activity requirements have been estimated from experience and rig observations - sticky cuttings, etc. Experience has shown in the Gulf Coast region that shallow formations can be balanced with activities of around 0.75 Aw (equivalent to 25 wt% calcium chloride brine or 250,000 ppm water phase salinity). In deeper formations, activities of 0.50 Aw (equivalent to 30 wt% calcium chloride brine or 300,000 ppm water phase salinity) are typically specified.

Given the critical need to properly balance the formation reactivity, field methods for estimating the cuttings activity are available, but not widely used⁵. Recent adoption of automated, computer controlled hygrometers has resulted in improved accuracy for activity measurement for mud and cuttings⁶ (see Photo 1). These instruments improve the

accuracy by including temperature monitoring with digital recording of the hygrometer sensor output.

Even when the cuttings activity is measured accurately, using the activity value derived from these measurements can have errors. The main source of error is the equilibration of the cuttings with the drilling fluid while the cuttings are transported out of the hole. When drilling fast hole with big cuttings in shallow zones, this error is minimized. As the hole gets deeper and drilling slows, cuttings become smaller and are exposed to the drilling fluid longer. Larger sloughings and cavings are also suspect because of their likely long residence time in the wellbore.

Relating surface activity measurements to downhole activity measurements can also be a problem. Research^{7,8} has determined that downhole activity of shale formations can tend to be lower than measured on surface. This would suggest that field practices for activity control of drilling fluids would tend to exceed downhole shale activity by a substantial margin⁹.

Cote Blanche Island Field - S/L 340 #187

Cote Blanche Bay Field producing sands lie in close proximity to salt formations. This requires drilling in formations that have been altered by exposure to salt. Several important differences exist between formations near salt and those that lie in relatively undisturbed geologic settings. The first difference is that salt is a plastic material and, under downhole conditions, will cause anomalous high horizontal stresses in adjacent formations¹⁰. In order to prevent wellbore instability in this situation, a mud density higher than that required to balance the pore pressure is required. Another difference is that the salt can affect the water demand of the shale formations near it.

In this well, three sidetracks were required to achieve the objective sands at a total depth of 15,600 ft. Considerable hole enlargement was observed from under surface casing to total depth (see caliper log Figure 1). Since oil mud was utilized, wellbore enlargement was expected to be related to high stresses related to the proximity of salt. Increasing mud density to near 13 lb/gal (1.5 SG) helped to improve wellbore conditions and allowed the eventual completion of the well.

Cuttings from the well were analyzed to determine if the properties of the formation could also be a factor in the wellbore instability. The analysis of the results (see Table 1) indicates that the cuttings contain halite. Saturated sodium chloride has an activity of 0.75 under ambient conditions. The activity of the cuttings was measured at 0.70, which is an equivalent activity to 280,000 ppm calcium chloride brine. This is the same activity as the mud system used to drill the well. Initially, it was thought that this activity would be adequate for drilling in this area. When on the next well in the field, the S/L 340 #191 ST#1, similar instability problems occurred, the drilling fluid activity was examined again.

Estimating Downhole Activity Requirements

Direct measurement of the activity of cuttings did not indicate that activity would be a problem. The estimation of activity requirements from estimated stresses was initiated.

The simplest method for this purpose was proposed by Mondshine¹¹. In his paper, the required water-phase salinity is estimated by determining a surface hydration force that is the difference between the overburden pressure and the pore pressure at the depth of interest. For this well the value of the overburden pressure was estimated at 1 psi/ft (22.6 kPa/m) and the pore pressure at 9 lb/gal (1.08 SG). At 15,100 ft (4,600 m) of depth this yields a surface hydration force of 8,025 psi (55,400 kPa). This hydration force is translated into drilling fluid water phase salinity by estimating the salinity of the shale pore fluid and determining the salinity required to achieve the surface hydration force as an osmotic pressure. Using the chart provided by Mondshine¹¹, a water-phase salinity of 370,000 ppm was predicted to be required (see Figure 2) when the interstitial water in the shale is saturated.

Other alternative methods for estimating the required water-phase salinity were also considered with similar results⁹. The main consideration in determining the salinity requirements was to accept that the shale was saturated with sodium chloride. Then, additional salinity above saturated sodium chloride would be required to balance the water demand from the geologic stresses that have forced the pore water from the shale as it compacted.

Cote Blanche Bay Field - S/L 340 #191 ST#1

After drilling below surface with the lower salinity (270,000 to 300,000 ppm) to a depth of 14,633 ft, the wellbore conditions deteriorated and the drill string became stuck on a trip back to bottom at 13,986 ft. The wellbore conditions on the well had deteriorated to the point that a casing string was required. 7-5/8 in casing was set to 13,108 ft and cemented. At this time, the increased salinity for the oil mud was implemented. Since salinities above 400,000 ppm calcium chloride have caused emulsion instability and water-wetting of mud solids, the range of 380,000 to 400,000 ppm was specified.

Drilling proceeded using a 12.5 lb/gal fluid in a trouble free manner to the top of geopressure at 15,241 ft. After taking a kick, the mud density was increased to 14.8 lb/gal and the well logged and casing ran to 14,758 ft.

The caliper log is shown in Figure 3. The enlarged portion at the top of the interval is a portion of the previous hole section that had not been covered by the casing string. It is much improved over the caliper from the #187 well.

Wellbore Stability Analysis

Another approach to examining this problem is to utilize wellbore stability prediction software to make the analysis. A program that includes stability prediction with a chemical/osmotic model using shale and mud activity values is available¹². The program was used to estimate safe mud weight ranges for this well using the following parameters:

Model for stability analysis: Mohr-Coulomb
 Overburden gradient - 1.00 psi/ft (22.6 kPa/m)
 Minimum horizontal stress - 0.68 psi/ft (15.5 kPa/m)
 Maximum horizontal stress - 0.94 psi/ft (21.2 kPa/m)
 Pore pressure - 0.47 psi/ft (10.6 kPa/m)
 Shale activity - 0.48 A_w

Figure 4 gives the wellbore stability case for the 0.44 A_w mud used to drill the trouble free hole, #191. It shows a stable wellbore for a mud weight in the same range as that used to drill the wellbore. Figure 5 shows the case for the 0.7 A_w mud used to drill the unstable hole, #187. While the predicted mud densities for a stable wellbore are unrealistic, it does give an indication that mud density is not a practical solution to all wellbore stability problems.

Downhole Simulation Testing

Drilling with fluids that have much lower activities than the formations drilled through is a commonplace occurrence. Many times a shallow high activity formation is penetrated and the activity of the mud is lowered to compensate for deeper formations. In order to test the effect of a low activity mud on a relatively high activity shale, a downhole simulation test using a shallow Pleistocene gumbo type shale with a surface activity of 0.88 and a downhole activity of 0.94 was drilled with an oil mud with an activity of 0.5. These results can be compared to previous studies using the same shale⁸. Although water was extracted at a rate of 0.21 mL/hr, which is a relatively high rate, there was not any loss of hardness or signs of instability in the test. Photo 2 shows the results of this test and can be compared to other studies using this shale.

Common sense, however, suggests that utilizing a mud with an activity only marginally lower than the lowest expected downhole formation activity is usually the best course. Another parameter that has not had much study in the osmotic process has been the rate of water extraction. It is possible that two non-aqueous drilling fluids of identical activity could extract water from shale at widely different rates.

Conclusions

The recognition that formations near salt can have a high interstitial salinity will result in increased salinity requirements for a controlled activity oil mud. There are a number of methods that can be used to estimate the required salinity/activity of the drilling fluid. These methods should take into account the stress state of the formation.

The application of the salinity estimation process resulted

in a low activity, high salinity drilling fluid being used on the Cote Blanche Bay field well S/L 340 #191 ST1. This fluid was successful at reducing hole enlargement and, by providing improved wellbore stability, helped in the drilling of the well.

Wellbore stability analysis software can be used to explore the effects of changing water phase salinity with variations in the downhole stress state and formation activity. This can give insight into the allowable variation of the drilling fluid salinity and the sensitivity of the solution to formation properties. Downhole simulation testing can be used to explore the effects of changing the fluid activity on a real downhole shale under wellbore conditions without the expense and in a controlled environment.

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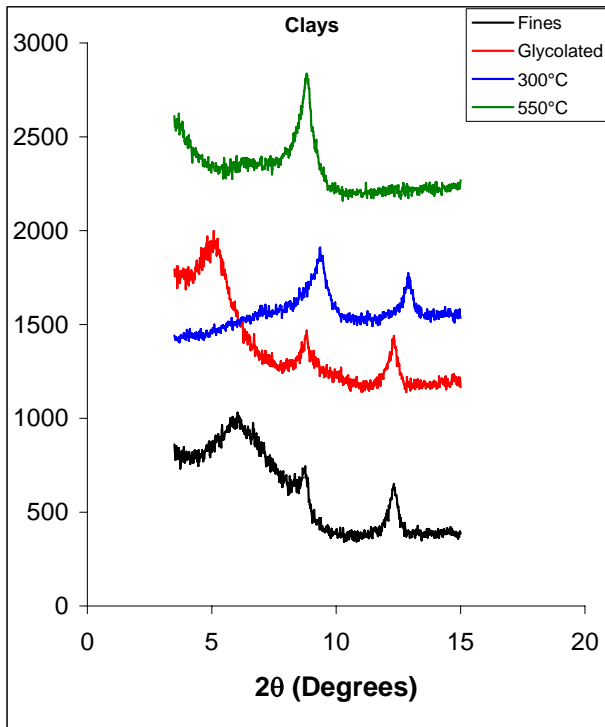
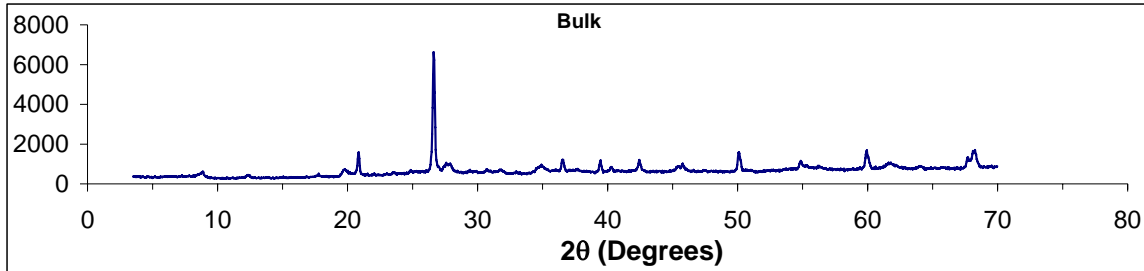
Table 1 - Cuttings Analysis

Mineralogical Interpretation and Data

Project: ANA 1310

Sample: 13,180 ft.

Description: S/L 340 #187, St. Mary's Parish, LA



Bulk Composition -	wt%
Quartz	45
Feldspar	20
Calcite	0
Dolomite	0
Siderite	0
Pyrite	0
Halite	5
Barite	0
Total Clay	30

Clay Composition -	wt%
Kaolinite	18
Chlorite	4
Illite	39
Smectite	24
Mixed-layer	15
Illite/smectite	45 / 55

CEC - **meq/100 g**
33.9

Moisture - **wt%**
12.2

Specific Gravity - **Air Pyc.**
2.66

Shale Equivalent Water Activity - **A_s**
0.702 / 19.7C

Interstitial Cations and Anions -		meq/100 g	
Sodium	22.9	Chloride	16.2
Potassium	0.2	Sulfate	0.2
Magnesium	0.1	Carbonate	4.3
Calcium	0.0	Bicarbonate	2.7

Exchangeable Bases -	meq/100 g
Sodium	11.4
Potassium	1.9
Magnesium	0.4
Calcium	26.1

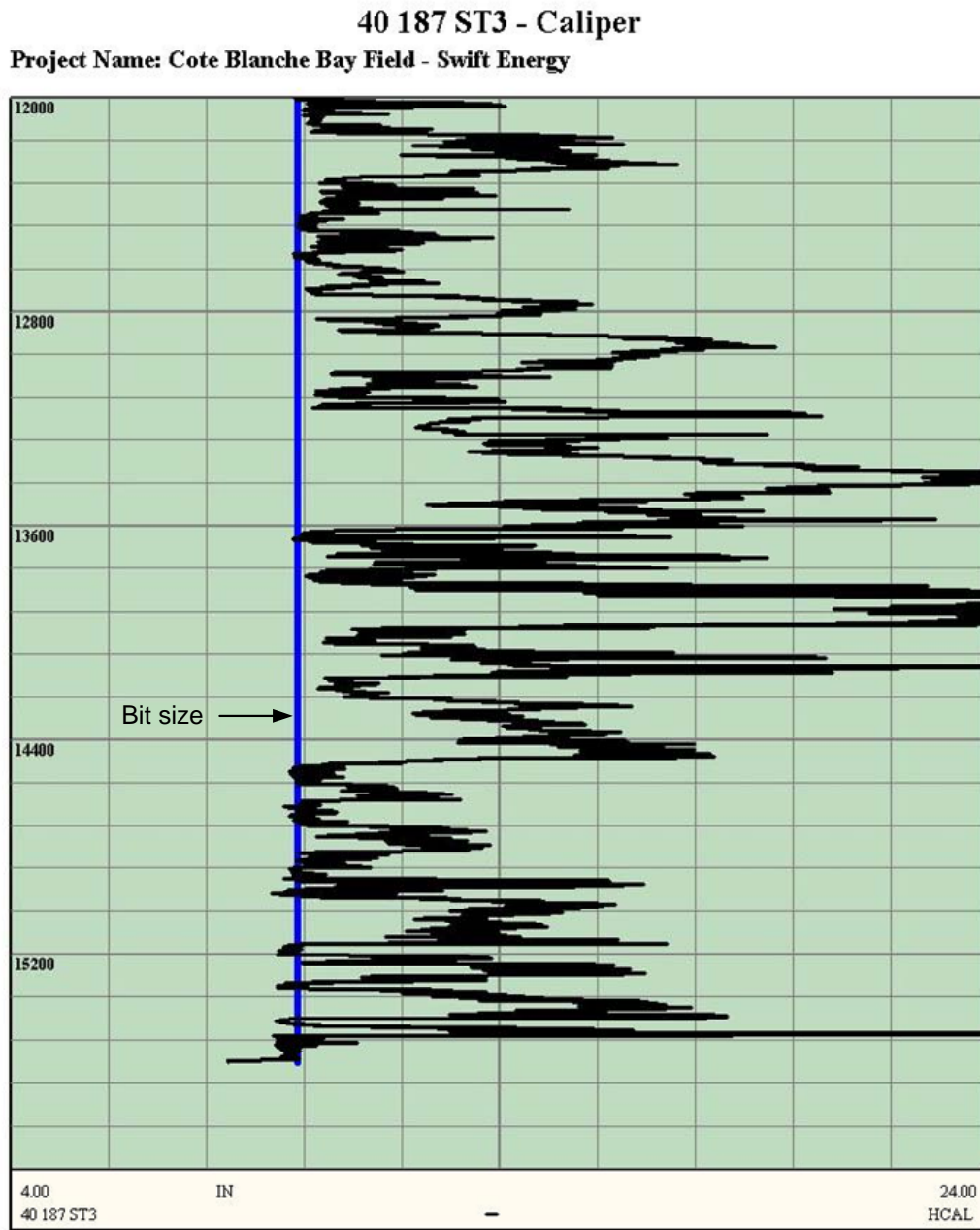


Figure 1 - Caliper Log - Cote Blanche Bay Well 187

Oil-mud-salinity requirements

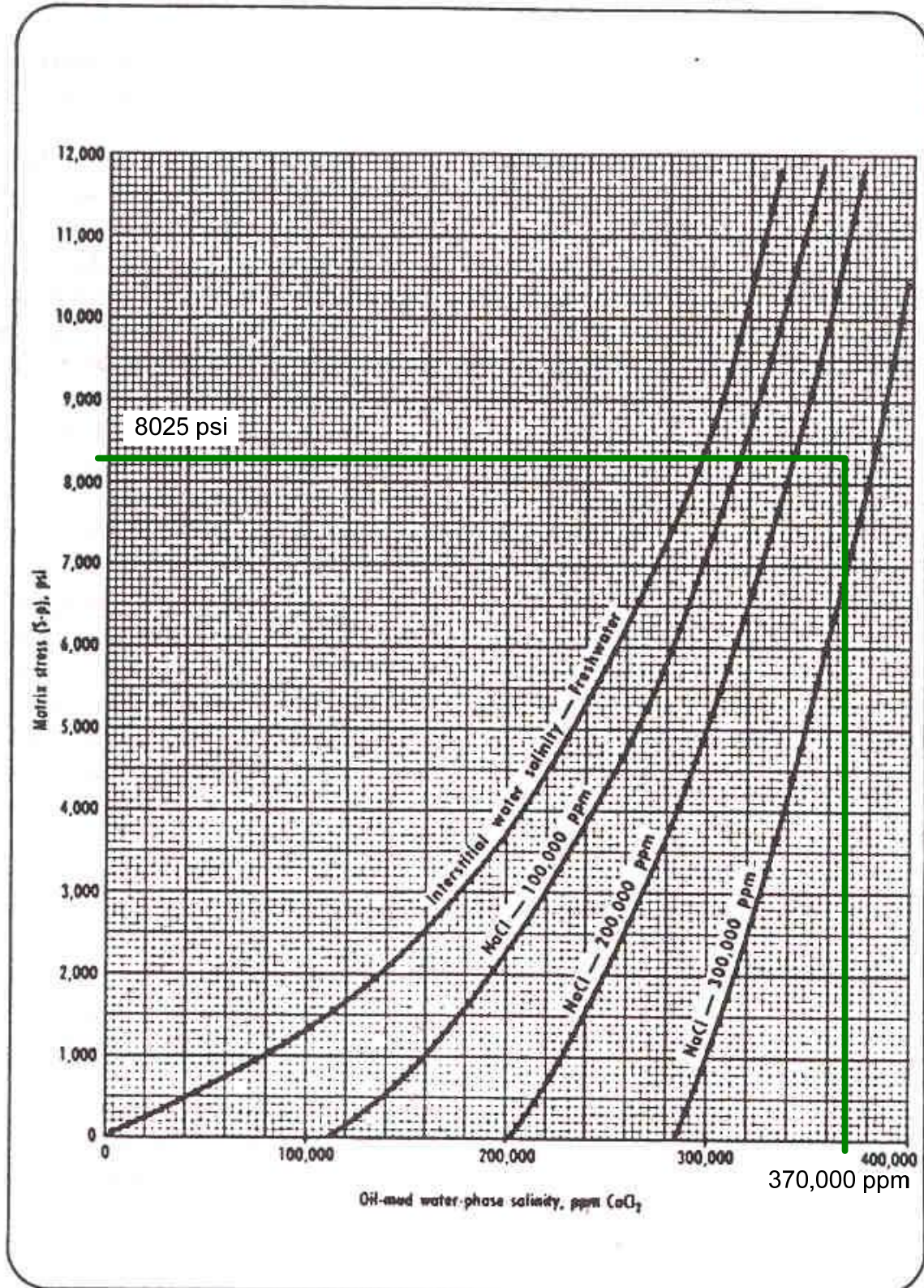


Figure 2 - Estimated oil-mud water phase salinity requirements

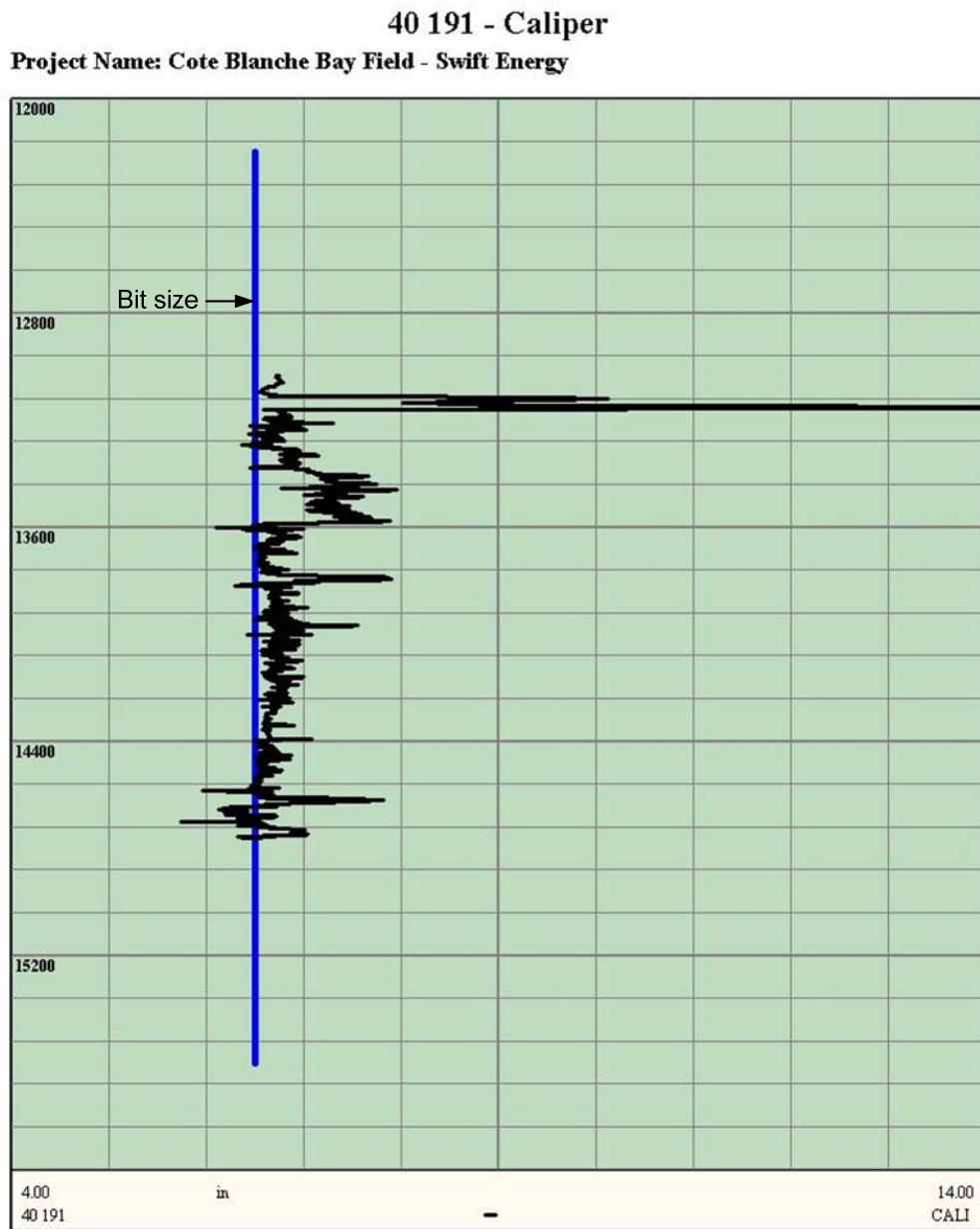


Figure 3 - Caliper Cote Blanche Bay 191

Estimate with 0.44 activity

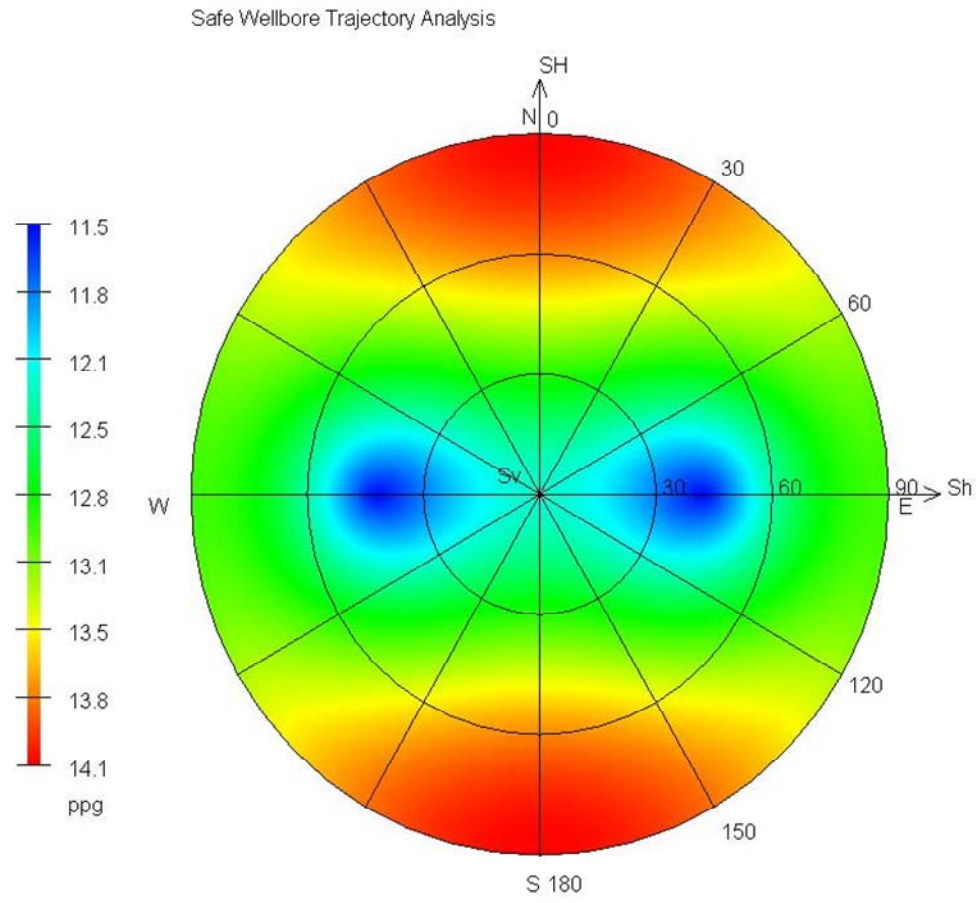


Figure 4 - Stability case for 0.44 Aw

0.7 Activity Mud

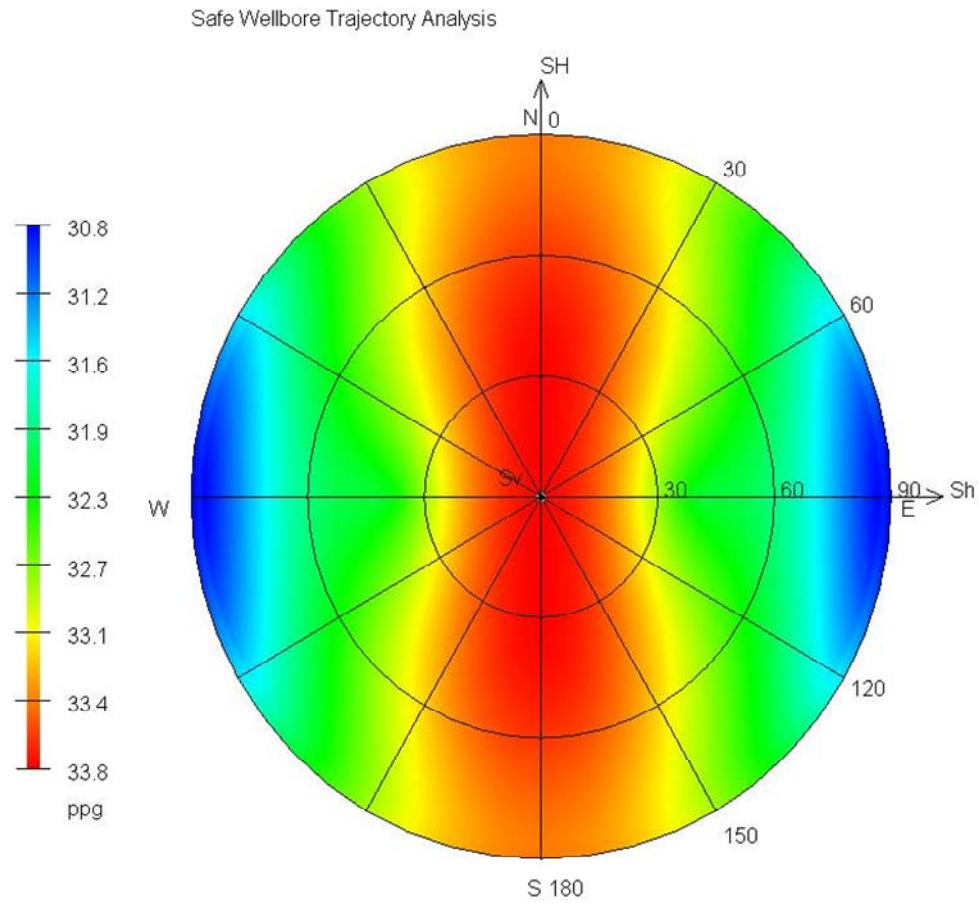


Figure 4 - Stability case for 0.7 Aw



Photo 1 - Automated activity measurement system



Photo 2 - Shallow Pleistocene shale drilled with 0.5 Aw oil mud