A LITERARY REVIEW OF WELL-BORE INSTABILITY ISSUES OF UNCONVENTIONAL SHALE PLAYS AND MITIGATION TECHNIQUES

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ABSTRACT

The shale revolution in the continental United States has reinvigorated the Oil and Gas Industry. According to the Energy Information Administration, 4.2 million barrels of crude per day is produced directly from tight oil plays in the United States in 2014. This accounts for around 49% of total U.S. crude oil production. Although much progress has been made to be more efficient time and money wise; there are still technical issues that are being addressed.

Drilling through shale has many obstacles that plague the industry. It is well known that shales have a strong affinity for water. When water is absorbed, the stability of the shale is reduced. Cohesive strength is reduced which causes the shale to either expand or crumble. The amount of water absorbed depends greatly on the characteristics of its clay mineral and the ionic concentration of surrounding fluids.

This study takes a literary review of wellbore stability of unconventional shale plays in the continental United States and methods to improve drilling practices to account for this issue.

INTRODUCTION

To understand shales and why they are unstable, it is important to delve deep into the mineralogy of shales. It is also important to review what the core root causes of shale wellbore instability are. To fully understand these issues that plague the industry, two shale plays were chosen for study. The first reservoir selected, is the Bakken Shale located primarily in North Dakota. The reason the Bakken was chosen due to it being an oil rich rock. This will aid in the analysis of an oil reservoir. The second reservoir studied is the Haynesville shale, which is primarily located in Louisiana. This reservoir was chosen because it is a very hostile gas play.

The objective is to observe instability issues for both types of reservoirs, and what mitigation techniques have been implemented. Other drilling issues in these plays will also be touched on.

CAUSES OF INSTABILITY

There are a few causes of wellbore instability. These include chemical and mechanical failures that can be broken down into further sections. These include stress re-distribution, volume change, pore pressure, water reactivity, and thermal expansion.

OSMOTIC SWELLING OF SHALE

When a clay particle is immersed in water, exchangeable cations are attracted to a negative charge to achieve an electrically neutral system. Osmotic swelling occurs because the ion concentration in the layers of the shale are higher than the free pore water. This forces water towards the clay surface. The aqueous solution is separated from pure water by a slightly permeable membrane. The water then passes through this membrane, by osmosis, and continues to swell the shale. This is why it is referred to as osmotic swelling.

HYDRATION SWELLING

Hydration of shales is an “interfacial phenomenon” that is common in clays due to their high surface area. Water is absorbed between the lattice layers of the clay, as well as the surface of the particle. The hydration energy of the interlayers determines the degree of water absorption.

INSTABILITY AND FAILURE OF BRITTLE SHALE

A brittle shale is a shale the remains competent in air but will form into hard-angular fragments when exposed to water. These brittle shales are usually not swollen, or softened when in contact with water. Brittle shales that are invaded by drilling fluid through an old network of microfractures that breaks the bonds of any potential bonds of hydration which weakens the shale mechanically and chemically. This situation worsens when there are high horizontal forces present. As a result, the wellbore is enlarged.

INSTABILITY AND FAILURE OF SWELLING (DUCTILE) SHALE

Shales that contain a signifigcant amount of montmorillonite will absorb water by surface hydration and cause an unstable wellbore. When invaded by drilling fluid, the shale will swell and expand, thus causing a constriction of the well bore. This is a problem for drillers because the current way of compensating for this phenomena is to increase mud weights. Spalling is also to be expected when the reservoir conditions have high horizontal stresses.

STRESS RE-DISTRIBUTION ISSUES

One of the assumptions made when discussing wellbore instability is that the rock formation is in a state of equilibrium. When the wellbore is being constructed, the stresses of the removed material is transferred to the remaining formation material. To make up for the change in stresses, it is required to manipulate the drilling fluid accordingly to create a stress re-distribution around the wellbore. However, this may result in shear stresses in the formation to exceed the formation strength which leads to a stress-induced wellbore failure.

VOLUME CHANGE ISSUES

Due to the volume change of the rock matrix during drilling results, especially since shales have low permeability, in an excess of pore pressure. This excess pore pressure will reduce the effective confining pressure on the wellbore which causes wellbore instability. Again, a common way to counteract this is to increase mud weight. However, excessively high mud pressure may result in hydraulic fracturing or shear failure.

FILTRATE AND PORE PRESSURE ISSUES

By drilling in an overbalanced condition without a flow barrier present at the wellbore wall will cause fluid to penetrate the formation. Without a physical membrane on the wall, an effective barrier will not be formed due to low permeability. When the drilling fluid penetrates the formation, the pore pressure near the wellbore wall increases. The increase in pore pressure reduces the effectiveness of higher mud weights which leads to a less stable wellbore. The increase in pore pressure depends on the mud filtrate and formation fluid properties.

WATER REACTIVITY

As discussed previously, water and the charge of the clay impacts wellbore stability greatly. The small pore size and negative charge of clay makes shales exhibit membrane behavior. The driving force involved in water transportation is the chemical potential of a fluid in regards to salt concentration. This is why brine water is less reactive in shales.

With drilling fluid being less reactive than water in the shale, an osmotic backflow of pore fluid from the formation will reduce the pore pressure due to mud pressure penetration. If the backflow of the formation into the wellbore is greater than the inflow of drilling fluid, this would result in a dehydration of the formation. The increase of effective mud weight and formation strength will lead to a more stable wellbore.

If the drilling fluid has a high chemical reactivity potential, then the shale will begin to absorb water. Two things might occur in this scenario; either the water platelets will move apart causing swelling of the clay, or an increase in stress if hydration is constrained. This, again, will cause a change in stress distribution near the wellbore which causes wellbore instability. The swelling will depend greatly on the elastic properties of the shale.

THERMAL EXPANSION

Drilling fluid is used for many things including moving cuttings up the wellbore, preventing kicks, lubrication, and cooling of downhole equipment. The temperature difference between the drilling fluid and the formation will result in a heat transfer. The thermal expansion of water is much higher than that of a rock matrix. This expansion could create an increase in pore pressure.

The thermal expansion of the rock matrix under constrained conditions will result in a thermal stress. The increase in thermal stress, as well as the increase in the pore pressure, will create an unstable wellbore. On the other end, if a formation is cooled; a decrease in pore pressure and hoop stress will create a more stable wellbore.

Hoop stress is mathematically defined as:

$$\sigma = \frac{F}{tl}$$

- F is the force exerted circumferentially on an area of the cylinder wall
- t is the radial thickness of the cylinder
- l is the axial length of the cylinder

STUDY OF IN-SITU STRESS REGIME

A study was done to compare mud support systems and how they impacted wellbore distress. In the Figure 1, each category was explained.

“Area A represents those stress regimes in which wellbores of low inclination, oriented in the direction of the horizontal stress are more stable in comparison with other combinations of wellbore direction and inclination;

Area B represents those stress regimes in which wellbores of any trajectory are almost equally stable;

Area C represents those stress regimes in which wellbores of low inclination oriented in the direction of horizontal stress are more stable;

Area D represents those stress regimes in which wellbores of high inclination oriented in the direction of horizontal stress are more stable;

Area E represents those stress regimes in which wellbores of high inclination oriented in the direction of horizontal stress are more stable.”

Wells that were analyzed in Field “A” show that it is more favorable to drill high inclination wells in the direction of minor principle horizontal stress. Table 1 indicates that wellbores with a range of inclinations were drilled. Most wells drilled did not report significant drilling problems. Well #3 is considered very safe due to it being the closest in the optimal direction in regards to horizontal stress. This is further reinforced by the lower mud weight needed during drilling. Higher mud weights were required for wells #4 and #6 because they are highly inclined and drilled in the direction of major principle stress.

However, this analysis only took into account the Mohr-Coulomb Failure Criterion. This means that only minor and major principle stresses were accounted for. Intermediate principle stresses were neglected. The radial stress is the minor principle stress and the hoop stress is the major principle stress. However, the hoop stress is not exactly in a principle stress direction because some shear stress components change direction slightly. However, this can be considered negligible.

TIME DEPENDENT WELL-BORE STABILITY

Looking at Figure 2, one can see that maintaining an open hole can produce an increase to pore pressure over time which creates an unstable wellbore. This, along with rig costs, is why having an efficient drilling program is a must. By not moving quickly to complete the wellbore construction, shale is able to increase pore pressure. This is likely due to the above causes previously discussed. However, it was observed in this study that the rate of increase of pore pressure does in fact decrease with elapsed time.

OIL BASED MUDS

Oil based muds began development in the 1960s to address several drilling problems including prevention of formation clays that react, swell, or slough after exposure to water.

Oil based fluids used today are formulated with either diesel, mineral oil, or low-toxicity paraffin’s. The electrical stability of the formation water phase is monitored to help ensure that the strength of the emulsion is maintained at or near a predetermined value. As previously discussed, this is important to note because the formation water is still able to react due to pressure differences and ionic charges of drilling fluids.

A common additive used to increase system density is Barite. This additive is used because the specific gravity the oil used is lower than water. A specially treated bentonite is used as the primary viscosifier in most oil-based systems. This is what aids in returning cutting to surface. Oil-wetting is essential for ensuring that particulate materials remain in suspension. Oil based systems usually contain lime to maintain an elevated pH which will resist the effects of hydrogen sulfide and carbon dioxide gases, and enhance emulsion stability.

Arguably the best benefit to oil based drilling fluids is that it will cause shale inhibition. The high salinity water phase helps to prevent shales from hydrating, swelling, and sloughing into the wellbore by having a neutral ionic charge. Most conventional oil based mud (OBM) systems are formulated with calcium-chloride brine, which appears to offer the best inhibition properties for most shales. However, other salt solutions have provided quality results as well. Oil based systems generally function well with an oil/water ratio of from 65/35 to 95/5.
Though oil based muds are very common when drilling in shale formations, they have downsides. The mud is very expensive since the majority of the drilling fluid is comprised of diesel. Rigs typically add an additional surcharge for working with OBM's. Also, there are many environmental aspects to keep in mind. This is why technology in creating drilling fluids that are water based are being explored.

BRINE MUDS

It is no secret that KCl is popularly used as a drilling fluid. The ionic charge helps reduce the swelling of young shale plays that possess smectite clays. Anionic based materials are the most common products used in drilling fluids. A pH of 7 typically reflects an anionic environment. This charged product can negate the charge of the clay particles. However, highly anionic fluids are very dispersive in a reactive clay. A cationic fluid can possess inhibitive qualities but it tends to create a flocculated fluid. This means that the fluid cannot form a quality mud cake due to "clumping" up the drilling fluid.

There are some advantages to using NaCl over KCl. The reason is that NaCl is more soluble that KCl. NaCl solutions have higher base viscosities and lower water activity than concentrated KCl solutions, thus giving higher osmotic pressures. This then causes them to be better equipped to reduce filtrate invasion of the shale. Studies were conducted to test the stress and strain of shales after being exposed to different drilling fluids. Studies concluded that NaCl and KCl are not ideal candidates for drilling fluids, but are great inhibitors when mixed properly with different chemical agents.

BRINE MUDS MIXED WITH VARIOUS POLYMERS

As seen in Table 2, the experiments conducted show that the use of NaCl in a concentration of 10% along with 5% physical sealing agent and the A1 polymer gave the best results in comparison to the other fluids. Shales exposed to this drilling fluid had nearly the same strength as the original native rock sample. This indicates a better wellbore environment. It must be noted that the NaCl is more soluble than KCl and also had elevated viscosities as well as higher osmotic pressures. NaCl solutions works in tandem with systems which enhance shale membrane efficiency. Although this solution shows promise, the weight of the mud still must be calibrated correctly prevent tensile and shear failures. The focus of these experiments were to prevent shear failure which is common amongst shales.

NANO PARTICLE TECHNOLOGY

Perhaps the latest development in shale inhibition is Nano-particle technology. Silica nanoparticles were used in drilling fluids to attempt to create a physical seal around the wellbore, thereby stopping water and fluid filtration through osmotic measures which would stop clay swelling. There was success in the lab, but is still currently waiting on field test data.

These nanoparticles made of silica decreased reservoir permeability by 98% in lab studies when the drilling fluid consisted of 3% weight of the total water based fluid. The same permeability decrease also occurred in other shale samples. It was found that the best nanoparticle size of the silica was 5 nm as these were able to penetrate the formation further creating a better seal. It is recommended that different sizes be deployed into the drilling fluid system, but data and time is still needed to test which combinations works the most efficiently.

However, there was only limited success in brittle shales as the particles struggled to physically plug off the micro-fractures. While these samples didn't experience swelling, the water reactivity increased thus increasing the near well bore pore pressure. This environment creates an unstable well bore.

Technology is currently in development to create chemical coated silica nanoparticles that would shut off water filtration from reservoir fluids, as well as cut off mud filtration of the drilling fluid into the formation. Nanoparticle drilling fluids experience decreased cost estimates, and is safe for the environment. The purpose of the nanoparticle research was to create a drilling fluid that wasn't oil based so it is unknown if this mud system would work well in tandem with an OBM system.

HYDRATION SUPPRESSANTS

Hydration suppressants were developed in the early 1990's to attempt to quell shale instability without having to switch to an oil based drilling fluid. The modified poly-amino acid hydration suppressant developed is completely water soluble, low weight organic compound that exhibits a low charge. The material is environmentally safe, as it contains no heavy metals. When added in a concentration of 1-2%, the clay material exposed behave as relatively inert solids.

However, the suppressant developed was meant for clays that consist of high concentrations of smectite. The suppressant works by attaching itself to clay particles and neutralizing the negative or positive polarity. Once the polarity has been neutralized, the capability of the reactive shale to generate viscosity, thereby creating an increase in pore volume, is greatly diminished. When the swelling of the clay particles has been substantially reduced, an increase on fluid loss can occur. The suppressant does not affect the capabilities of conventional fluid loss additives such as starch, lignite or lignosulfonate.

The hydration suppressant also doesn't dehydrate bentonite or any reactive drilling solids. Chlorides also do not affect the performance of the suppressant like it does other chemical additives. The suppressant is also effective in a divalent ion environment which helps neutralize reactive clay particles and the formation fluids. The suppressant also works in both a saline solution as well as a brine solution.

The best application of the hydration suppressant was to simply add the material to the drilling fluid instead of trying to build the fluid around the suppressant. By designing it this way, costs could be lowered because the suppressant is very expensive.

Field tests were conducted in Wyoming. As seen in Figure 3, samples retrieved were placed under axial stress conditions to evaluate time till failure. The treated samples lasted much longer than the untreated sample retrieved. It is also important to note that due to the stability of the formations, the drilling fluid, and the cuttings; drill time was expedited by about 20%.

LATEX POLYMERS

It has been discovered that a latex polymer added to a water based drilling fluid can reduce the rate the drilling fluid pressure invades the borehole wall of a formation during the drilling process. The polymer is capable of providing a deformable latex film, or seal, on at least a portion of the shale formation. The "film" or "seal" are not a completely impermeable layer. The seal is considered to be semi-permeable, but is at least partially blocking fluid transmission sufficient to result in a great improvement in osmotic efficiency.

A latex polymer combined with a precipitating agent, such as an aluminum complex, will substantially reduce the rate of mud pressure penetration into shale formations. The pressure blockage and pore size that can be blocked are all increased by the latex addition. This will inhibit drilling fluid from invading the formation thereby maintaining wellbore stability.

The essential components of this water based drilling fluid are the latex polymer and water, which makes up the bulk of the fluid. This polymer doesn't affect other drilling fluid additives that aid in drilling properties. The latex polymer is preferably a carboxylated styrene/butadiene copolymer. There are other variations that also create the desired membrane, but must be chosen on a case by case basis. The best results occurred when the latex polymer made up between 5-10% of the drilling fluid. This polymer also works in fresh water and brine drilling solutions. This makes the polymer very flexible in terms of usage.

Adding a surfactant will also aid the polymer. If a surfactant is present, the surfactant treated latex would wet the formation surface and accumulate to form a film or coating that seals fractures and defects in the shale. It has been determined that surfactants are particularly helpful when salts are present in the drilling fluid, and are not as preferred in fresh water fluid systems. The main downside to the latex polymer is that it doesn't fair very well against high temperature. Technology is being developed to create latex polymers to withstand the heat of hotter reservoirs, however, this latex does handle temperatures up to 200 degrees Fahrenheit. This would enable the polymer to be used in select Bakken wells where the downhole temperatures reside within the stated parameters.

HAYNESVILLE GEOLOGY AND RESERVOIR CONDITIONS

The Haynesville shale presents different drilling issues when compared to the previously discussed Bakken shale. The Haynesville shale is a high-pressure, high-temperature reservoir that primarily produces a dry gas with no condensate. Most of the Haynesville produces a low amount of carbon dioxide as well as a low amount of hydrogen sulfide. The water to gas ratio stands at 100bbl/MMscf, which indicates a very low water saturation. This is important to note since water is a primary cause of wellbore stability issues with smectite filled shales.

The most sought after and developed areas of the field reside in harder, more brittle shale regions. However, the formation is incredibly heterogeneous. The properties and shale composition will change rapidly, even over short distances within a horizontal wellbore. However, the northern part of the field experiences higher initial production as well as higher ultimate recovery. This is in part because the formation is brittle, and therefore created a better environment for micro-fractures to form. This area of the field tends to be more calcite rich. The southern part of the field, tends to possess more smectite, which is the clay that is most associated with swelling and causing drilling issues.

There are also areas within the Haynesville shale play that have a thickness interval of around 400 feet and other areas with a thickness of 70 feet. The thinner sections have more consistency of containing calcite rich shales with higher free gas porosity, which in turn make it the better producing area of the Haynesville play. However, the thickness of the more smectite filled areas still produce as much as the thinner areas because of the sheer volume of producible rock.

HIGH PRESSURE AND DRILLING UNDERBALANCED IN THE BOSSIER

The Haynesville shale possesses an incredibly high pressure and high temperature environment. The majority of kicks that occur happen when drilling the curve in the Bossier formation. The pore pressure in this area is 16.5 ppg. Conventional methods used to control the kicks usually resulted in fluid loss into the fracture network. It was theorized that if the Bossier formation was allowed to flow and deplete, then the Haynesville could be drilled with a lower mud weight.

So drillers began to drill using a closed system that utilized a choke to detect an instantaneous increase in pressure without the need to observe the flow. A managed pressure/underbalanced drilling process was developed. The system consisted of a high pressure rotating head which is a high pressure seal that sends the downhole fluid from the wellbore to the mud/gas separator while maintaining drilling operation to make hole, a choke manifold, and a mud-gas separator. When a kick was detected, the driller would pull off of bottom, stop the mud pumps, and close the choke. The influx would then be circulated out using the drillers' method to maintain a constant bottom-hole pressure.

The driller's method is one of several methods to kill the well. The main idea of driller's method is to kill the well with constant bottom-hole pressure. The driller's method of well control requires two complete and separate circulations of drilling fluid in the well.

The first circulation removes influx with original mud weight. When starting to bring pumps up to speed, casing pressure must be held constant until kill rate is reached. Then drill-pipe pressure is held constant to maintain constant bottom-hole pressure which is normally equal to, or slightly greater than pore pressure. Drill-pipe pressure will be held constant until influx is removed from annulus. Since the Haynesville is a gas play, the mud volume will expand when it comes close to surface therefore you will see an increase in pit volume and casing pressure. After the kick is totally removed from the well, when the well is shut-in, drill-pipe and casing pressure will be the same value. If not, it means that there is influx still left in the wellbore or trapped pressure.

The second circulation kills well with the predetermined kill mud weight and formulation. When the required kill mud weight is mixed, it is the time to start the second circulation of the driller's method. This process begins with bringing pumps to kill rate by holding casing pressure constant. While circulating with the kill mud, casing pressure must be held constant until kill mud reaches the bit. After that, it is required to hold drill pipe pressure constant then continue circulating with constant drill pipe pressure until kill mud weight reaches at surface. Then shut down pumping operations and observe the drill-pipe and casing pressures. If the well is successfully killed, both drill-pipe and casing pressure will be zero. If not, there is some influx still in the well.

This method of drilling cut down drill time by approximately 20 days. The mud weight used could also be lowered from 16.5ppg to 14.4ppg. This also decreased the time to penetrate the formation by more than 200%.

ISSUES WITH WATER BASED MUD SYSTEMS IN THE HAYNESVILLE

Oil based muds are primarily used in the Haynesville play for multiple reasons. The down-hole temperatures are a major issue when drilling with WBM's. At temperatures exceeding 300° F, the standard viscosifying agent, xanthan gum, deteriorates rapidly and treatment costs become too unrealistic. Commercial grade bentonite or any clay based formulated drilling fluids pose challenges as well. Between the high temperatures and the influxes of carbon dioxide, rheological issue arise.

Carbon dioxide must be removed from the bentonite solution, typically using a calcium source, generally lime. However, at such high temperatures, maintaining a large excess of lime is not a viable option as these temperatures may cause fluid cementation. At lower lime concentrations, the fluid viscosity becomes unstable as carbon dioxide influx levels continues to vary. When this occurs, there are many mud related issues such as hole cleaning problems, fluid loss control, and high friction coefficients. This then becomes a wellbore management issue, rather than a shale instability issue.

Achieving the correct amount of lubricity for the horizontal application becomes difficult as well due to higher mud viscosity, carbon dioxide intrusions, and higher muds weights to combat the increased bottom-hole pressure required for drilling operations. Adding lubricants has proven to be ineffective. They have failed to reduce the friction coefficient when compared to muds without the additive.

OIL BASED MUDS IN THE HAYNESVILLE

As previously discussed, oil based fluids used today are formulated with either diesel, mineral oil, or low-toxicity paraffin's. The electrical stability of the formation water phase is monitored to help ensure that the strength of the emulsion is maintained at or near a predetermined value. Oil based systems usually contain lime to maintain an elevated pH which will resist the effects of hydrogen sulfide and carbon dioxide gases, and enhance emulsion stability. Although the Haynesville has low carbon dioxide and low hydrogen sulfide, most companies try to mitigate it during the drilling process.

Arguably the best benefit to oil based drilling fluids is that it will cause shale inhibition. Oil based systems generally function well with an oil/water ratio of from 65/35 to 95/5. Most companies in the Haynesville tend to use a higher oil cut in their drilling fluid to help mitigate the swelling capabilities of the Smectite in the formation. Due to the many issues with water based mud systems, oil based mud systems are almost unanimously used in the Haynesville. There have been some field tests with polymers that have yielded successful results. However, most companies still prefer OBM's when drilling this shale play.

WATER BASED MUD WITH POLYMER ADDITIVES FIELD STUDY

By drilling in an overbalanced condition without a flow barrier present at the wellbore wall will cause fluid to penetrate the formation. Without a physical membrane on the wall, an effective barrier will not be formed due to low permeability. When the drilling fluid penetrates the formation, the pore pressure near the wellbore increases. The increase in pore pressure hinders the effective mud weight's ability to combat kicks from the formation which leads to a less stable wellbore. The increase in pore pressure depends on the mud filtrate and formation fluid properties.

This is why most drillers in the Haynesville prefer to drill underbalanced. The soft clay sections will react to the drilling fluid and thus increase in pore pressure will result. However, if mud weight increases, the more brittle shale will begin to fail as the drilling fluid's bottom-hole pressure might surpass the formations fracture gradient.

A water based mud system was formulated to handle the pressure, temperature and rheological issues that have plagued WBM systems for the Haynesville. After many lab tests on Bossier shale samples as well as Haynesville samples that varied in mineral content, a mud system was composed.

The team responsible for the new mud system then began a four well case study with an independent operator that used their mud when drilling the lateral in the Haynesville shale play. The specialized fluid system for these initial wells were built on location, thereby eliminating most transportation and liability costs of OBM's.

ROP for this mud system worked just as well as a comprehensive study of typical OBM drilling rates. Wellbore instability occurred in the wells, however this can be attributed to drilling underbalanced and the swelling of clays by pressure and volume differentials. Tight spots were back reamed and no issues arose setting the casing strings. It was concluded that, overall, the system performed as expected with ROP and wellbore stability matching that of prior OBM applications.

Two more wells were drilled using this water based mud system; however, they were located in the Red River Parish which has a more hostile drilling environment, with reservoir temperatures exceeding 350° F. Both wells were drilled with the same success as OBM systems in the area. The system even fared well when chloride levels exceeded 5,000ppm.

Even though this was a small sample size, there is promise of using a water based mud system that would lower drilling costs and have a lesser impact environmentally. The water based mud systems have also helped improve mud motor life by better reducing the overheating of the tool. This proposed system also decreased the friction coefficient during drilling operations. This can be seen in Figure 4.

STRESS RE-DISTRIBUTION IN THE HAYNESVILLE

The Haynesville shale play struggles in the lateral drilling phase with stress redistribution. As mentioned before, the formation is very heterogeneous. The “gumbo” clay sections that possess smectite are the problem areas as they react more than the calcite brittle shales. The soft shales swell, and move in on the wellbore which could cause stuck pipe and could eventually hang the casing. However, the sections of the lateral with the high calcite distributed shales are able to adapt and don’t react nearly as much as the softer shales. Figure 5 shows the heterogeneity of the formation.

The figure shows the brittleness evaluated for the Haynesville shale as well as a correlated brittleness curve. When drilling, the ideal shale is more brittle. This type of shale doesn’t swell, thereby not creating an unstable wellbore condition. The red sections of the log indicate a more brittle shale. The green sections contain more smectite which is a “gumbo” type shale that does cause instability. This log shows that the formation is very heterogeneous and thereby a more difficult well to drill and complete.

VOLUME CHANGE IN THE HAYNESVILLE

As previously discussed, volume change can have an adverse effect during drilling operations. Due to the volume change of the rock matrix during drilling, excess pore pressure results. This excess pore pressure will reduce the effective confining pressure on the wellbore which causes wellbore instability. The Haynesville shale possesses both brittle and soft-ductile shales. The volume change affects the soft shale while drilling when compared to the more brittle shales. This is an issue that hasn’t been solved in the Haynesville since most companies drill underbalanced; thus allowing a volume change to occur.

FILTRATE AND PORE PRESSURE IN THE HAYNESVILLE

As previously mentioned, by drilling in an overbalanced condition without a flow barrier present at the wellbore wall will cause fluid to penetrate the formation. Without a physical membrane on the wall, an effective barrier will not be formed.

This is why most drillers in the Haynesville prefer to drill underbalanced and circulate out the kicks using the drillers method. The soft clay sections will react to the drilling fluid and thus increase in pore pressure will result. However, if mud weight increases, the more brittle shales will begin to fail as the drilling fluid might surpass the formations frac gradient. If the lateral is drilled using a water based mud system, then the brittle shale may fail when coming into contact with the water.

CONCLUSIONS

The shale revolution in the continental United States has led to the advancement in drilling techniques, bit designs, and a technological boom in research and development of drilling fluids that will aid in cutting costs and providing a quality well-bore.

Drilling through shale has many obstacles that plague the industry. One unique issue that every company has faced is well-bore instability. This report has covered the main causes of well-bore instability of both oil and gas reservoirs, and expressed some mitigation techniques developed or are in current development by taking an in depth look at case studies as well as technical papers discussing advancement in this field of study.

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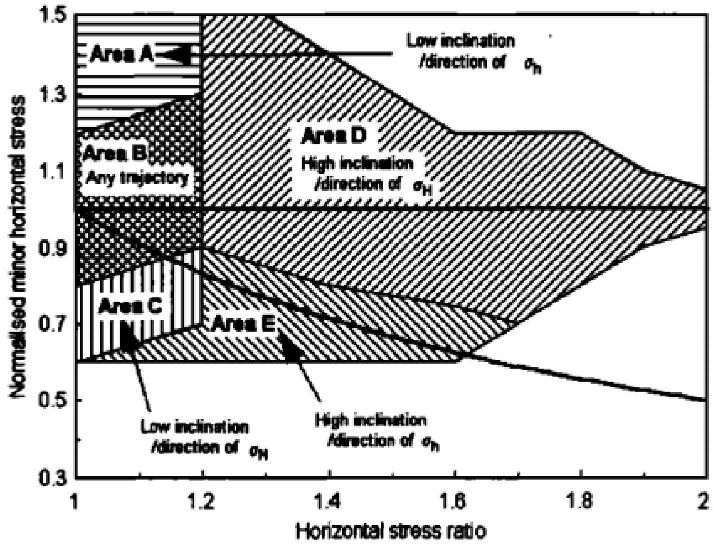

Figure 1. Optimum wellbore profile in relation
to in-situ stress regime (mean Strength).

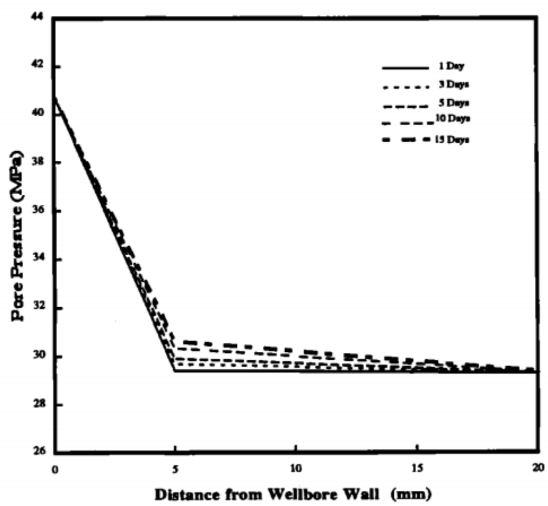

Figure 2. Variation of pore pressure distribution
profile in formation with open-hole duration

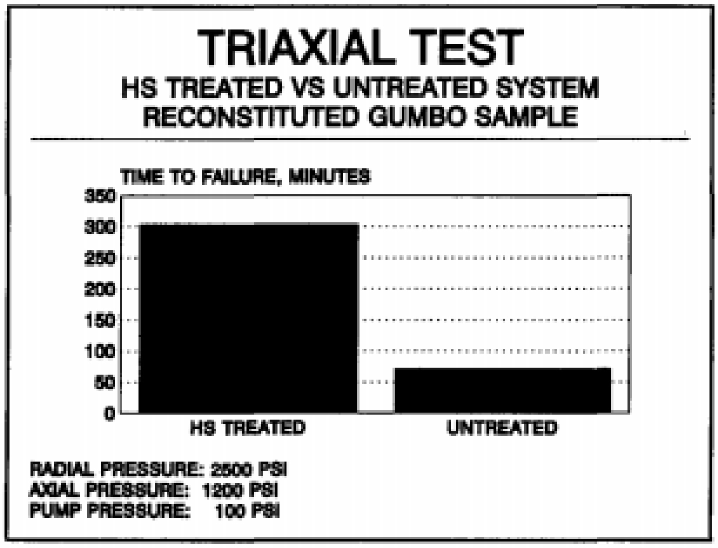

Figure 3. Difference in Failure Times Between Treated and Untreated Shale Samples

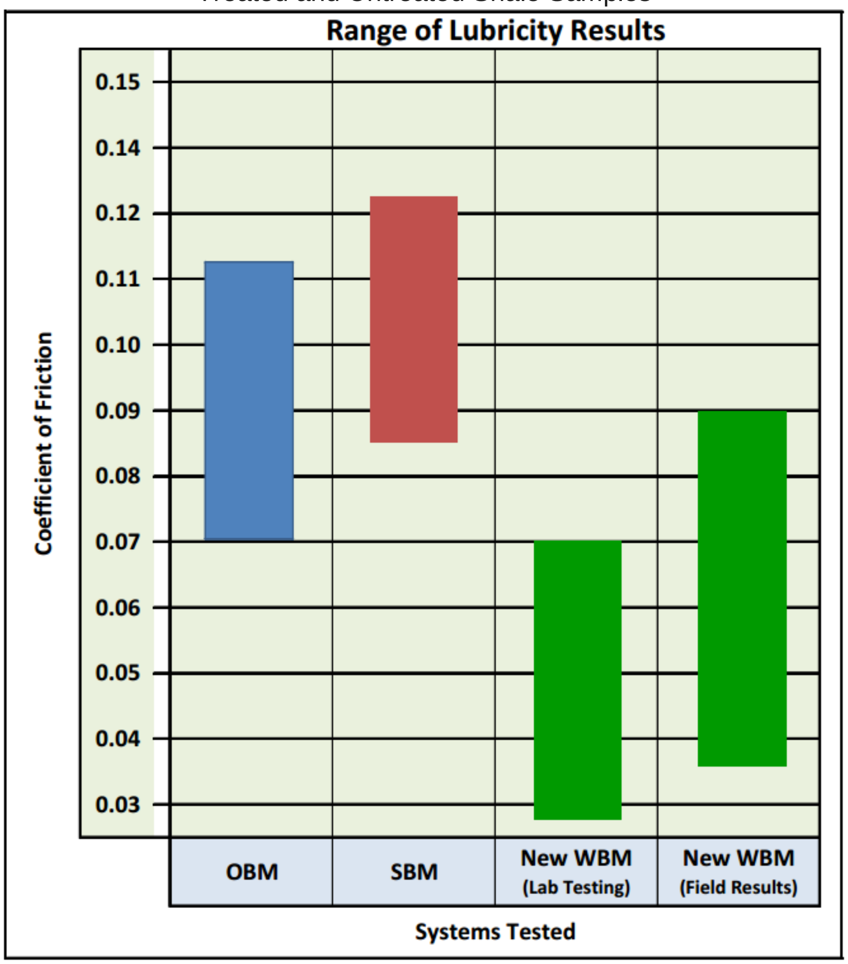

Figure 4. WBM vs OBM Lubricity Results

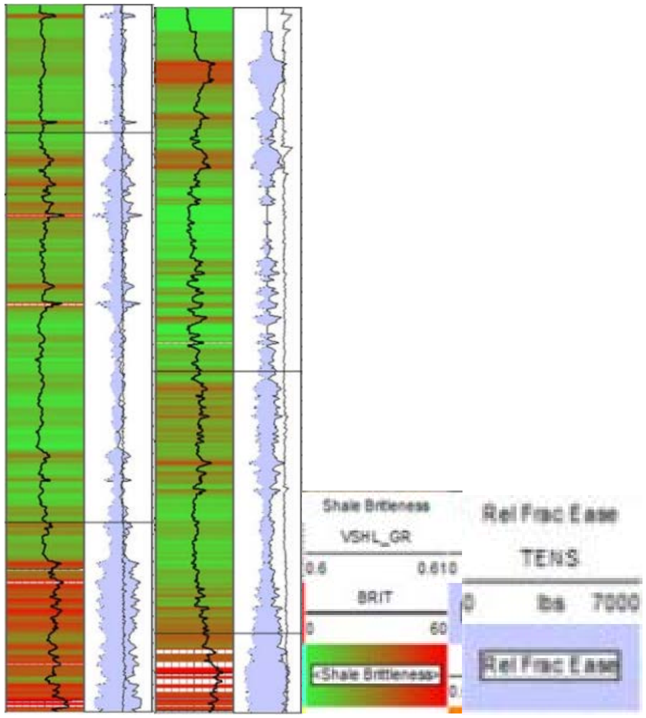

Figure 5. Shale Brittleness Shown from Log Analysis

Table 1. Wellbore Profile and In-Situ Stress Regime for Field A

Well	Direction (°)	Inclination (°)	Drilling Issue	Mud Weight (SG)
1	74	49	No	1.16-1.21
2	39	27	No	1.15
3	15	52	No	1.12-1.15
4	86.5	78	Yes	1.13-1.15
5	48	59	No	1.12
6	83	60	No	1.17

Table 2. Mechanical Properties of the Immersed Shale in Different Salt Solutions and Drilling Fluid Systems

Shale	Drilling Fluid	Confined Compressive Strength	Young's Modulus (MPA)	Poisson Ratio (μ)
A	Polymer	.11	777	.552
A1	KCL (5%)	3	-	-
A2	KCL (7%)	5	723	.322
A3	KCL (10%)	8	899	.388
A4	Polymer + KCL (5%)	5	532	-
A5	Polymer + KCL (7%)	7	612	.332
A6	Polymer + KCL (10%)	7	725	.433
A7	Polymer + 10% + Stabilizer 5%	7.6	855	.367
A8	Polymer + 10% + 10% Chemical Agent A1	12	703	.451
A9	Polymer + NaCl (10%) + Stabilizer (5%) + Chemical Agent A1 (10%)	19.2	1636	.293