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Wellbore Shielding Spacer System Technology Eases Pressure Gradient Uncertainty in Exploration Wells

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Abstract

Knowledge of actual frac and pore pressure gradients are critical during the cement design phase of well planning. Unfortunately, in exploration wells, engineers may be forced to estimate the frac and pore pressure gradients' values. Considering this, cement circulation can fail due to uncertainties in the engineering estimates. If errors in the engineering estimates cause partial to total lost circulation, at minimum the casing will not be supported. Some of these situations will require costly remedial work and in the worst case, the well must be skidded and re-drilled.

This paper will explain how a Wellbore Shielding (WBS) spacer incorporates technology that deposits a micron-thin barrier on the inside face of the wellbore. This deposited barrier, to an extent, isolates the formation from the full wellbore equivalent circulating density (ECD). Typically, in situations where lost circulation events occur due to an increase in cement-related ECD, WBS technology contributes to maintaining or regaining full circulation. Full circulation can be maintained even when the over-estimated frac gradient would normally result in a failure to achieve the required and/or desired Top-of-Cement (TOC). Without WBS technology, the design engineer would be forced to choose to use lighter, less capable cement and/or a slower than ideal displacement rate in an effort to minimize ECD. However, slowing the displacement rate adversely affects displacement efficiency.

We will present an example illustrating the WBS spacer's capability to prevent and cure losses, which can help the drilling engineer be successful even in wells with many unknowns.

Background

When drilling oil and gas wells, the drilling process is a step-wise process where a larger diameter hole is drilled, a slightly narrower length of pipe is cemented into that section of the wellbore, a slightly narrower hole is drilled, still narrower pipe is cemented, and so on until the Total Depth (TD) of the well is reached. There are many reasons for this approach, the primary being to keep formations with different pressure gradients isolated from one another. When drilling the wellbore many different layers are encountered/penetrated. These layers range from permeable to impermeable, over-pressure to depleted or highly depleted, dry, fresh water, brines, gas, oil, or hydrocarbon liquids, and some will contain a combination of fluids. To keep these zones and their contents isolated, the cement that is hydraulically forced into the annular gap must form an effective barrier across or between all of the layers that contain fluid or may take fluid.

Further complicating matters, prior to introducing cement into the annular gap that gap contains potentially hard to remove drilling fluid that could interfere with the bond between the cement and the wellbore face. In almost every instance that drilling fluid has been optimized for drilling purposes – cooling the bit, holding the hole open, removing cuttings, supporting the solids during static periods, etc. During drilling, mud is continuously circulated into the wellbore. For safety reasons, the wellbore is never without this column of mud, and completely displacing this mud from the wellbore is rarely considered, and not part of the drilling fluids design optimization process. However, this removal step is critical in the creation of a strong cement bond and ensuring the integrity of an oil or gas well capable of producing problem-free for the useful life of the reservoir.

Best Practices for Cementing Integrity

Numerous cementing studies were conducted in the late 70s and early 80s[1,2] to determine the best cementing practices to increase the odds that an effective barrier would be placed during the cement job. Generally, these standards have been widely accepted and well proven throughout the last 30+ years. Unfortunately, in today's cost-driven marketplace, not all of these practices are followed to an optimal extent.

The quality of the annular cement barrier can be optimized by incorporating as many of the following best practices as possible into the cementing program.

Mud Conditioning

The drilling fluid can be conditioned for cementing both mechanically and chemically.[3] The mechanical conditioning involves circulating bottoms-up at least twice. Studies have shown that after four hole-volumes, additional benefits are minimal. Several studies have been conducted to help determine how much is enough. One method involves adding dye or some tracer particles, such as mica or walnut hulls. Ideally these particles will be significantly different from the already present mud components to be readily obvious upon return to the surface. In deepwater, where returns are taken to the mud line, hollow glass bubbles can be easily identified due

to their reflectivity, as they float up. If the openhole volume and mud-conditioning rate are known, the time to make a round trip can be easily calculated. If the tracer material returns to the surface early, the most likely explanation is the openhole volume has been effectively reduced by immobile drilling fluid. Thus, the conditioning time must be extended and ideally the circulation rate will also be increased. Other suggested methodologies involve the use of a very sensitive and accurate pressure gauge mounted near the wellhead. Start circulation at a moderate to slow rate. As the less mobile mud begins to circulate, the effective hole size increases and pressure decreases. At any overly low fixed rate, this pressure drop (resulting from the increase in effective hole size) will stabilize. If the circulation rate is then increased, another portion of the immobile mud will begin to circulate. Once the circulation rate is increased to a sufficiently high rate (for any given set of conditions), no immobile mud will be left and any additional increases in circulation rate will no longer correspond to the previously discussed pressure decline.

Anything done to the mud chemically to reduce the plastic viscosity (PV), yield point (YP), or static gel strength (SGS) will help with the mud removal process. If the same mud will be used to drill the next hole section, these modifications are rarely considered acceptable. However, if the mud will be hauled-off for disposal, these options may be more acceptable. If chemical treatments are to be applied, those modifications should be made prior to letting the mud go static and the casing run.

Pipe Movement

The simplest change that can be made to a cementing program to make a bigger impact is the addition of pipe movement.[4] The fluid motion induced by the pipe motion will make up for many other shortcomings. Both rotation and reciprocation will help. The movement does not need to be fast, 3 to 10 rpm or 2 to 3 minutes per joint. If the pipe is poorly centralized there will be wide side and a narrow side. The difference in frictional pressures between the wide side and the narrow side increases as the eccentricity worsens. Eventually the pressure differential is so great that there will only be flow in the wide side, meaning there will be zero cement along the narrow side of the casing/liner. Under identical conditions, when rotation is added, the pipe will drag cement into the narrow side. The flow rate along the narrow side will still be zero, but there will be some cement in this space.

Centralization

In a vertical well the pipe can hang in the middle of the wellbore. With deviation, gravity will force the pipe along the low side of the wellbore. With centralizers, rigid or bow spring, the pipe can be lifted off of the low-side allowing more complete cementing coverage. Centralization, or the lack thereof, does not just affect mud cleaning and the cement flow path, it also affects the overall cement placement and can seriously lower the top of cement coverage and overall well integrity.

The laws of Physics and Fluid Dynamics cover the flow of mud and cement in the annulus. Fluids flow will always be through the path of least resistance. If the pipe is fairly well centered in the middle of the annulus, the flow will be more or less equal on all sides.[5,6] If the pipe is off-center there will be a wide side and a narrow side. Because the frictional pressure drop is greater on the narrow side, the fluid will differentially flow at a greater rate in the wide side. As the difference between the annular gap on the wide and narrow sides increases, the flow-rate differential also increases. Before the narrow-side gap goes to zero, the narrow-side flow rate will normally reach zero. Obviously having no cement on one side of the pipe is not ideal. The other manifestation of poor centralization is Top of Cement (TOC) inequality. When cement returns are observed early, it is often indicative of a wide-side channel. If there is a lack of centralization and it does not eliminate the flow in the narrow-side, there could be an -indeterminant TOC. The low-side TOC is the actual TOC for isolation purposes and will often be much lower than the intended height.

Pump Rate

In the past, discussions have involved the relative merits of plug flow versus laminar flow. Today it is believed that turbulent flow is optimal, but flow regime[7,8] only matters when trying to select the correct frictional pressure model. It is common practice to displace the cement and/or condition the mud as fast as possible, regardless of flow regime, providing pressure limits are observed. Two bbl/min is better than one, four is better than two, eight is better than four, etc. The mixing rate for the spacer and the cement is less important than pre-job conditioning and displacement rate. The mixing rate should be selected to optimize the mixing process. Properly prepared fluids are critical and could be the subject of an entire paper on its own.

Shut Downs

If possible, the wellbore fluid should remain in motion from the start of the mud conditioning process all the way up until the plug bumps. Any shut-down periods will allow the mud to begin to regain gel-strength, adversely effecting displacement efficiency.[9] Often shut-downs are unavoidable, but with proper pre-job planning, they can be minimized.

Spacer

There are two aspects of spacer design that effect displacement efficiency: rheology and volume. Even after pumping bottoms-up twice, some well conditions are such that significant amounts of gelled annular mud will still be present. If the spacer is designed sufficiently thicker than the drilling fluid and a good rate is maintained while it is being circulated up the annulus, the spacer can remove most of the remaining gelled mud not previously circulating. If a vast majority of the annulus is displaced prior to the introduction of cement, the likelihood of effective barrier placement increases. The best spacers have been engineered with a simplistic method to deliver any required rheology. While surface viscosity is easy to measure, it is actually the rheological properties under downhole conditions that matter, if the goal is optimizing conditions for the formation of an annular barrier.

There are two rules-of-thumb often used to determine spacer volume. Spacer volume must be sufficient to effectively

displace the drilling fluid (provided the rheology is correct) and completely separate the mud from the cement. Required spacer volume if often determined based on either a 10 to 15 minute contact time or 1000 to 1500 ft of annular fill. The term contact time is a reference to the time the spacer will be in contact with any specific location in the annulus. The calculation is very simple and straight forward. Divide the spacer volume by the pump rate that will be expected, when the spacer will be flowing past that part of the annulus. Conversely to use contact time to determine spacer volume take your rate and multiply it by the desired contact time.

Working with annular fill, 1000-1500 feet of fill, is a decent rule of thumb but is not very practical with large hole sizes. For instance, common spacer volumes are 30 to 100 bbl (contact times of 10 - 15 minutes for rates of 3 to 10 bbl/min). However, if one looks into cementing a 20-in. casing in a 26in. hole, without any washout, the volume factor is 0.2681 bbl/ft. That is 268 bbl for 1000 ft and 402 bbl for 1500 ft. Even on critical jobs where the operator is really interested on successful achievement of annular barrier placement, 402 bbl of spacer would be deemed too pricey.

Better than relying on a rule of thumb would be a simulation that shows the volume mud being removed. In today's age of high-powered computers, Computational Fluid Dynamics (CFD) software, typically run by the service company, can model and predicted interface boundaries and displacement efficiencies. Good CFD software will also model the fluid-to-fluid interface. As the spacer is pushing mud up/along the annulus, the leading edge of the spacer and trailing edge of the drilling fluid are mixing. The longer these two fluids are in dynamic contact, the larger the interface becomes. This interface is actually a contaminated mixture of the two systems. At the trailing edge of the spacer, a similar cement-spacer contaminated interface will be building in length and volume. If insufficient spacer is pumped, these two contaminated intervals will join up to be one large section of contamination leaving no clean spacer to separate the cement from the drilling fluid. If sufficient spacer volume was planned and it was designed at the correct rheology, a good CFD model can help operations obtain a cemented interval that is relatively mud free and with at least a few barrels of clean spacer remaining, as the plug bumps.

Wellbore Shielding Technology

The premise of wellbore shielding (WBS) technology is that it is possible to deposit a shield of optimized material on the inside face of the wellbore to isolate the formation from fluid invasion from operations in the wellbore. If done ideally, the particle size distribution (PSD) and mechanical properties of the WBS material will be such that the shield is placed on the inside face of the wellbore and not in the formation as to be non-damaging (reservoir compliant). Additionally, this shield or barrier will be fluid tight and capable of withstanding substantial pressure differentials without parting. Optimally the PSD will be such that an effective barrier is formed across various sized natural fractures and multiple permeability and porosity ranges. Additionally, there is a need for the material to be non-shear degrading to provide the same degree of formation protection in the field as demonstrated in the lab.

When drilling in areas with pressure gradient uncertainty, cementing choices often come down to a balancing act between minimizing the risk of sustaining losses by utilizing lighter fluids at lower circulation rates versus using more optimal slurry densities at a higher circulation rate (from a barrier design perspective) with the potential for higher risk of losses. The incorporation of WBS technology into the cementing plan can, in some cases, mitigate the risks of losses even when employing a more optimal barrier design strategy with potentially higher slurry density and higher circulation rate. With the deposition of an effective WBS, pressure spikes above the frac gradient can be isolated from the formation. If the formation does not feel the full ECD, circulating pressures above the fracture gradient will often not equate to wholesale losses.

This case history reported in this paper incorporates WBS technology designed into a cementing spacer with the capability to mix to any required downhole rheology at bottomhole circulating fluid temperature (BHCT) in excess of 300°F by simply adding more or less of the base spacer concentrate. Adding more and more "stuff" to the cement, is typically a bad idea. By adding the WBS technology to the spacer, the cement design team can focus on keeping the cement fluid until it gets placed and then having it set rapidly.

Case History

In operations in the Powder River Basin of Wyoming the complexities of wellbore designs, ever challenging geological obstacles, and stringent regulations, require the cementing process to undergo an extremely thorough technical analysis to ensure success.[10] This case study focuses on a pair of wells ~0.7 miles apart that target the Parkman Sandstone in the Powder River Basin.

In the Powder River Basin, wells targeting the Parkman Sandstone are typically drilled as a monobore with a 9⅝-in. surface string and a 5½-in. production string set in an 8¾-in. openhole. In the two subject wells, surface casing was set to ~2,200 ft, and the production strings were set at true vertical depth (TVD) of ~7,400 ft with total measured depths of ~11,845 ft. The measured bottomhole temperature (BHT) for both wells was ~190°F. One of the most significant challenges with wells targeting the Parkman Sandstone is maintaining circulation throughout the cementing operations. Typically, these wells also penetrate the low fracture gradient Fox Hills Formation. In both of these wells the Fox Hills was found at a TVD of ~6,000 ft. The critical formation in which to achieve coverage over is the Fox Hills. Both the Fox Hills and the Parkman formations can exhibit fracture gradients as low as 0.37 psi/ft. Table 1 summarizes the fluids used on the two wells.

On Well A, the first of the two wells to be cemented, a reactive spacer system was utilized in an attempt to combat the losses. This reactive spacer system included 20 bbl of water, followed by 20 bbl of a 9.2-lb/gal reactive spacer. Ahead of the cement, an additional 150 bbl of water was pumped (Figure 1). This second water stage was pumped to act as a non-reactive fluid barrier between the reactive material and the cement and to reduce the overall ECD exerted on the weak formations. The bond log showed sufficient isolation above the Fox Hills Formation, however the overall results indicated there was room for further optimization of the job design. As a result, a

comprehensive post job analysis was performed on Well A.

During the in-depth review of the data, a reduction in return rate made it obvious that a lost circulation event was experienced during the job. Figure 1 has a vertical red dashed line indicating the lost circulation event at the 250-minute mark. These losses were difficult to see during the job as the only monitoring of the return flow rate was at the shaker screens.

After calculating the return rate, it was determined that the lost circulation events caused such a decrease in annular fluid velocity that it in turn negatively impacted the displacement of drilling fluid. In Figure 2 it can be observed that at the real displacement rate, the spacer was too thin to effectively clean the wellbore. The result of having this reduced displacement rate can be observed in the bond log and bond log analysis displayed in Figures 3 and 4. In Well A, good cement was only found below 5400 ft and maybe partial isolation from 4500 – 5400 ft.

Solution: In an attempt to avoid the Well A losses during the cementing of Well B, the resulting decrease in annular velocity, and the associated lesser level of mud removal, it was decided to pump a WBS spacer ahead of the 11.5-lb/gal lead cement (the same density lead cement as used for Well A).

The WBS spacer system was selected for use in Well B based on the belief that a reduced flow rate up the annulus, caused by downhole losses during the first job caused decreased displacement efficiency. Additionally, a small amount of lost circulation material was added directly into the cement on Well B. One other slight difference being Well A was drilled using a water-based drilling fluid system with a density of 9.4 lb/gal and Well B utilized an oil-based drilling fluid system at 9.1 lb/gal. Forty barrels of the WBS spacer was mixed at 11.0 lb/gal and pumped ahead of the cement instead of the 9.2 lb/gal reactive spacer system. Both Well A and Well B used 13.5-lb/gal tail cement density.

The effectiveness of the WBS spacer can clearly be seen by comparing the calculated rate out curves in Figures 1 and 5. In a closed system, the rates in and out should match. During a cement job there are two primary reasons why these rates might not be equal. The most common reason is freefall. Whenever the pipe is loaded with enough cement of substantially higher density than the drilling fluid the cement will start to fall. During the onset of freefall, the return rate is actually greater than the pump rate. This phenomenon can be observed in Figure 5 between the job times of 42 and 90 minutes. Once enough cement reaches the annulus, the freefall volume in the top of the casing starts to back fill. For the next portion of the job, the return rate should be less than the pump rate (time range 90-140 min). From this point on the rates in and out should be equal. If the rates out is less than the rate in and it is not from freefall correct, the mostly likely explanation is a lost circulation event has occurred (Figure 1, vertical red dashed line at the 250-minute mark).

In Figure 5, a corresponding loss in return rate was not observed (as was in Well A, Figure 1), indicating the WBS benefit engineered into the spacer system provided the required control. The WBS spacer system was designed to generate the necessary barrier at the wall to resist the additional ECD required for mud displacement and cement placement. An extra 5 lb/bbl of the base concentrate was added to each bbl of spacer to aid in mobilization of the gelled and dehydrated drilling fluid.

Notice how in Figure 2 that for most of the cement interval the mud has a higher gel strength than the spacer's YP. In Figure 6, the rheological adjustability of the WBS spacer allowed its YP to be design substantially higher than what was pumped on Well A. As extra insurance, 20 lb/bbl of an optimized lost circulation material was added to the spacer system in Well B. As an additional contingency plan, a light loading of 1 lb/sk of a particulate lost circulation material was added to both the lead and tail cements.

To further aid in the reduction of ECD as the cement was being forced up the annulus, 100 bbl of water was pumped ahead of the WBS spacer system. (In Well A, 170 bbl of water was pumped ahead of the cement job.) A summary of the differences between the fluids pumped on the two wells can be found in Table 1.

The primary difference between these two cement jobs was the addition of the WBS spacer system pumped ahead of the cement on the second well. The resulting bond log showed a much more comprehensive level of isolation in Well B when compared to the results from Well A (Figures 3 and 4) and full circulation was achieved throughout Well B's job (Figure 5).

Summary

1. Wellbore shielding (WBS) technology can help isolate the formation from wellbore pressure, allowing successful placement of cement barriers.
2. Following displacement best practices will improve the quality of the cement barrier.

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Table 1. Comparison of Spacers

	Well A RS = Reactive Spacer	Well B WBS = Wellbore Shielding Spacer
Spacer 1 (Density – lb/gal / Volume - bbl)	Water – 8.33 lb/gal / 20 bbl	Water – 8.33 lb/gal / 100 bbl
Spacer 2 (Density – lb/gal / Volume - bbl)	RS – 9.16 lb/gal / 20 bbl	WBS Spacer – 11.0 lb/gal / 40 bbl
Spacer 3 (Density – lb/gal / Volume - bbl)	Water – 8.33 lb/gal / 150 bbl	-
Cement 1 (Density – lb/gal / Volume – sk)	Lead – 11.5 lb/gal / 441 sk	Lead - 11.5 lb/gal / 439 sk
Cement 2 (Density – lb/gal / Volume – sk)	Tail – 13.5 lb/gal / 1095 bbl	Tail – 13.5 lb/gal / 1066 sk

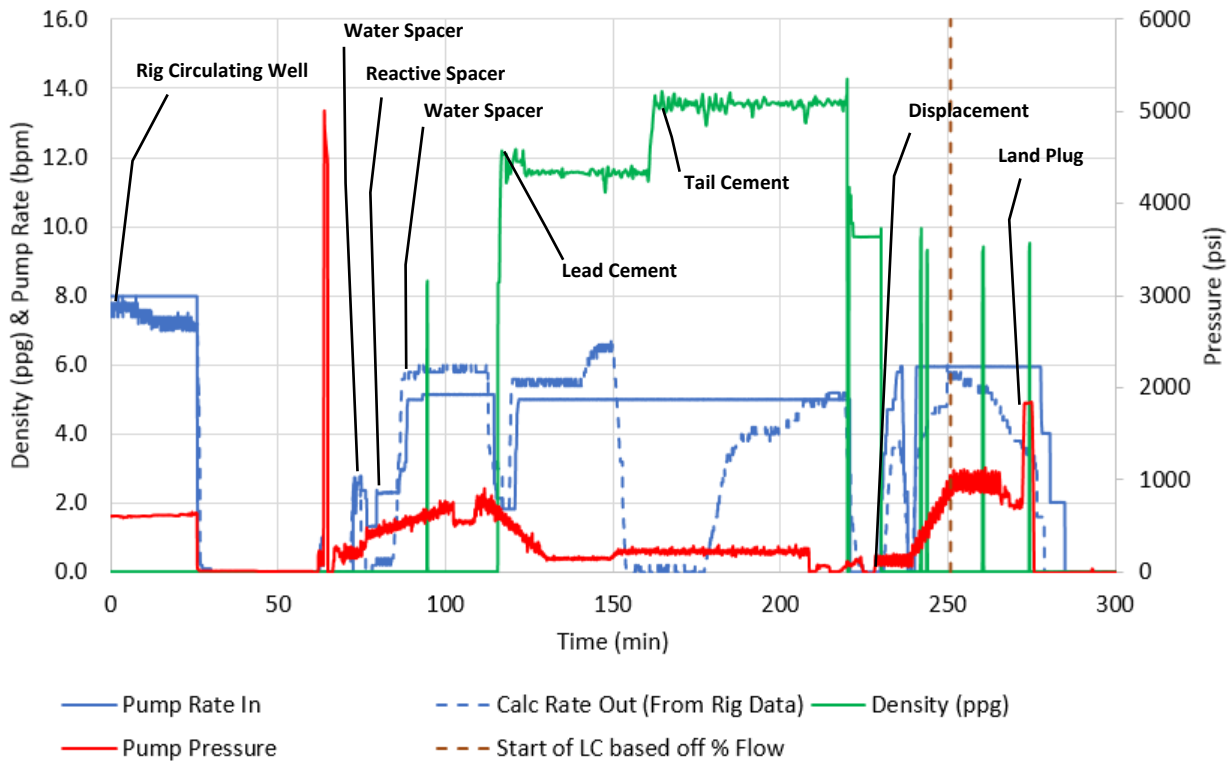

Figure 1. Well A Return Analysis. Note vertical red dashed line at 250-minute mark indicating lost circulation event and subsequent reduction in pump returns.

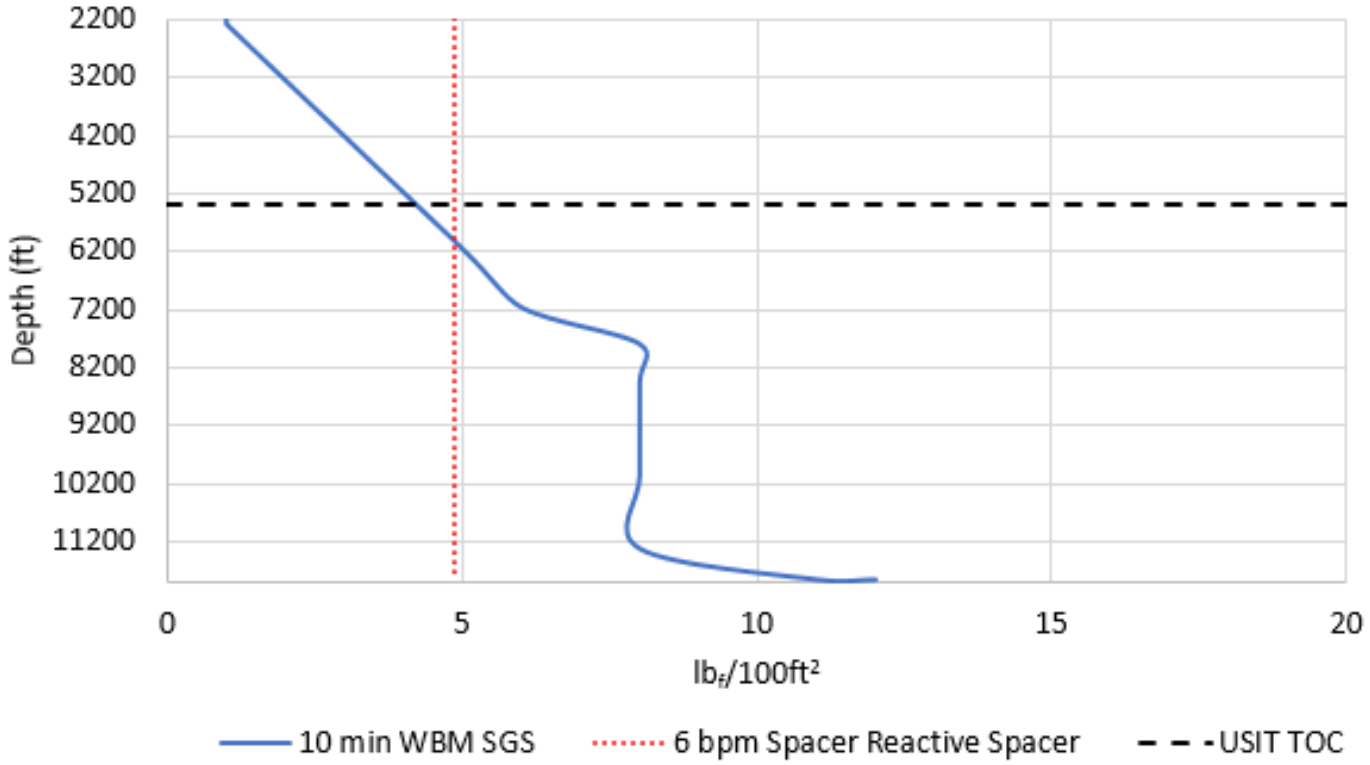

Figure 2. Comparison of Spacer Cleaning Ability Relative to Mud SGS on Well A. The "10 min WBM SGS" curve represents the reported 10-minute Static Gel Strength as reported on the mud reports. The "6-bpm Reactive Spacer" curve represents the calculated shear stress produced by the spacer at 6 bbl/min as a function of the annular geometry. The "USIT TOC" curve represents the top of cement from the bond log ran on the well.

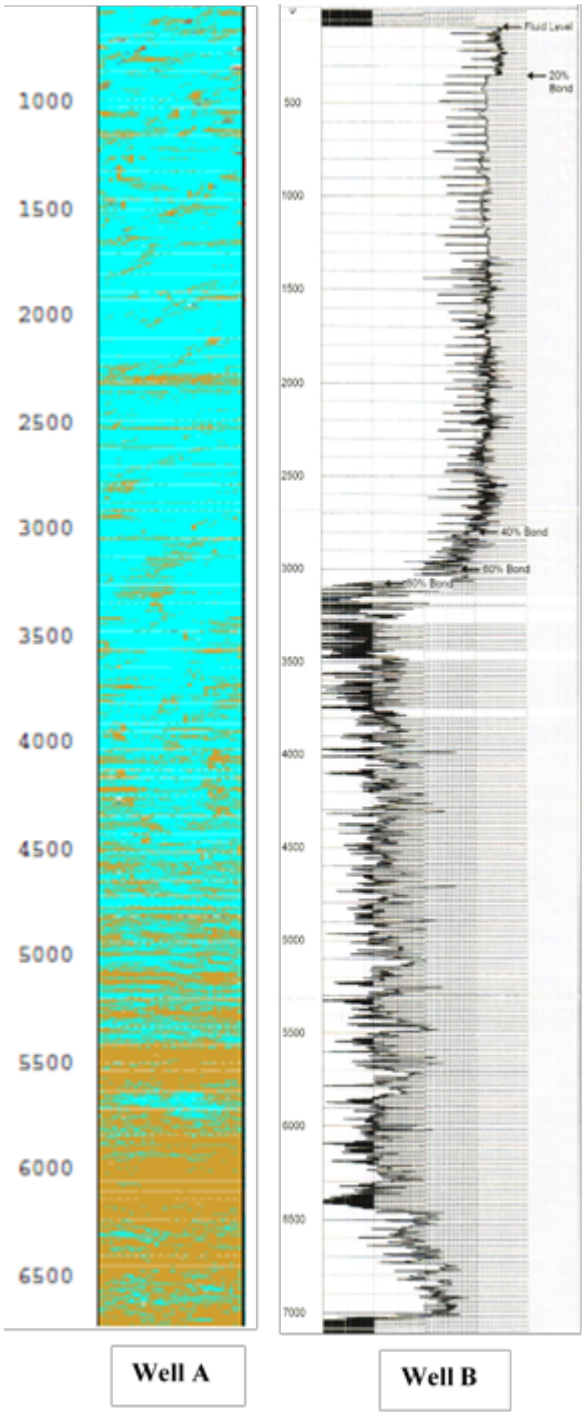

Figure 3. Overview of Bond Logs. Well A was logged using an ultrasonic tool, Well B was logged using an acoustic tool. The output from these tools allow for those trained in the art to draw conclusions about the quality of the cement job and the location of the cemented interval.

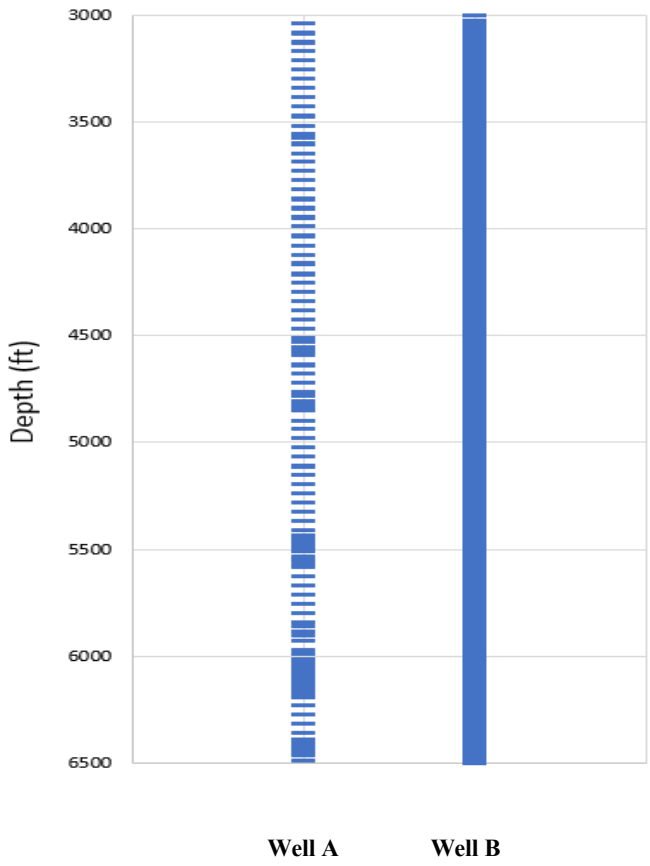

Figure 4. Analysis of Bond Logs. Using standard isolation values of greater than 3 mRayl's and less than 20 mV on the 3-ft amp respectively, an analysis of the logs in Figure 3 was performed to generate the above images. The more solid the bar, the better the quality of cement barrier.

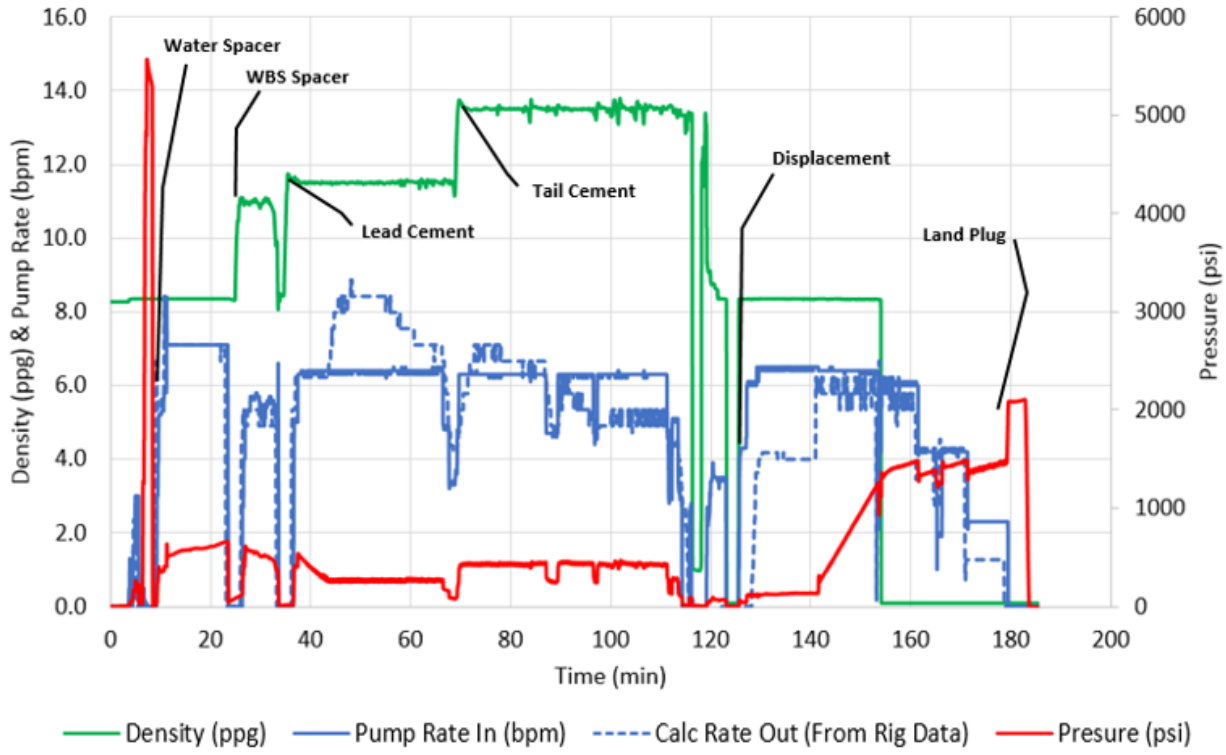

Figure 5. Well B Job Chart

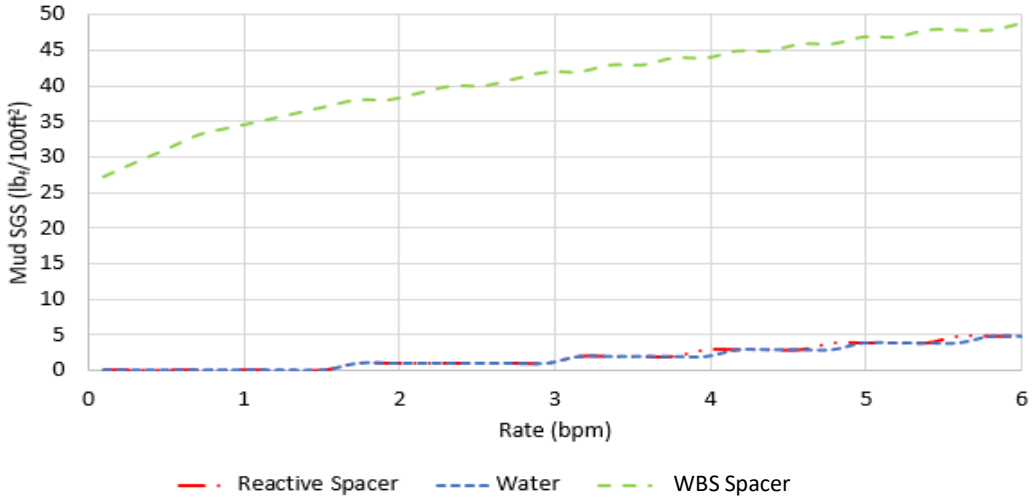

Figure 6. Spacer Hole Cleaning Capability. This chart shows the shear stress produced by the various fluids as a function of geometry. This calculated shear stress value is then used to determine what level of mud static gel strength can be removed. For example, if the fluid produces a 10 $lb_f/100\ ft^2$ shear stress than it is understood that this fluid could remove a mud that has developed a static gel strength of $10lb_f/100\ ft^2$.