InTuition Energy Associates Pte Ltd

Deepwater Horizon Macondo Blowout

A Review of Cement Designs and Procedures

Preliminary Report – To Be Finalized

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Executive Summary

- The Macondo blowout was almost certainly initiated by failure of the primary cement job in the 9 7/8" x 7" annulus which allowed gaseous hydrocarbon to enter the well. Gas migration probably began shortly after cement placement due to rapid decay of the very small overbalance pressure on the hydrocarbon-bearing zone.

- The cement design, in terms of composition, volume, performance and, arguably, density, was inappropriate for this casing string in this particular well. Better designs with superior properties could easily have been formulated and proposed for this critical cementing operation.

- Laboratory data presented for the cement slurry were inaccurate or misleading and misrepresented the properties and characteristics of the cement. Failure to identify the significance of these inaccuracies and inconsistencies, or to advise of their potential importance, almost certainly contributed to the subsequent disaster.

- Important additional laboratory tests that would have verified the performance characteristics of the cement and spacer systems proposed, and their suitability or otherwise for this application, were not carried out, or not reported.

- The cement failure allowed gas to invade the annulus and to make its way upwards to the casing hanger. Pressure on the unsecured (no lock down) casing hanger probably lifted the assembly and compromised the seal, allowing gas to reach the marine riser and/or drill pipe which was inserted at that time to conduct testing and to set an additional cement plug to suspend the well.

- The replacement of mud with seawater in the marine riser was probably a critical event, sufficiently reducing the pressure above the casing hanger and allowing it to be displaced upward by gas pressure beneath it, possibly compromising the BOP while simultaneously opening the flow path from the reservoir.

- Undertaking certain operations in the well (pressure testing and, in particular the negative test) while cement was not guaranteed to be set and mechanically competent was dangerous, given the configuration of the well.

- The use of a single production longstring in this well, with an incompletely cemented annulus and an inadequate second barrier, was inappropriate. At the very least, cement should have been brought into the previous liner to ensure coverage of all open formations and additional mechanical barriers should have been deployed e.g. swell packers. Ideally, the well should have been completed with a liner/tieback configuration.

- Apart from the fundamental cement job design issues, several other factors probably contributed to failure of the primary cement. Individually, these factors may not have been catastrophic but in combination they could probably have influenced the outcome.

- Insufficient mud circulation time, prior to the cement job, probably resulted in further loss of hydrostatic overbalance during, and immediately after, cementing due to gas in the mud being circulated back only to the riser.

- Poor centralization of the casing string, due to the use of an insufficient number of centralizers, may have compromised mud displacement and favored the creation of mud channels.

- The fact that no viscous pill was spotted in the rathole under the casing shoe may have increased the risk of cement contamination due to fluid density differentials. However, the significance of this is unclear and the evidence still suggests that the casing shoe/double flapper valve was closed and was **not** the entry point for gas into the well.

- While the well itself would still have been seriously compromised, the disaster and loss of life might have been avoided if several warning signs had been recognized for what they were and acted upon promptly.

A Review of Cement Designs and Procedures on Macondo

Introduction

This work was undertaken on behalf of, and at the request of, Transocean. The workscope involved a review of technical/commercial proposals and job designs prepared for the cementing of the 9 7/8" x 7" tapered longstring on the ill-fated BP Macondo-1 (MC 252 #1) exploration well in the Gulf of Mexico.

Also examined were laboratory results from a series of reports on cement tests undertaken by the cementing contractor, Halliburton. Laboratory procedures were assessed and compared with industry standard procedures used for cement testing and slurry composition was reviewed on the basis of its composition and characteristics.

In addition, various pieces of correspondence, including e-mails, daily drilling reports, post-job reports were examined for information, relating to preparations for the cement job, operational procedures followed and post-cementing procedures.

Finally, the findings of this review, based on the documents provided and interpretation of sometimes incomplete information , were considered within the context of the events aboard the Deepwater Horizon in the days leading up to 20th April, 2010.

The preliminary conclusions drawn are mine alone but they are supported by many individual pieces of information. However, they are, of necessity, still speculative insofar as the exact causes of the disaster are concerned. Hopefully, additional information will emerge in the coming weeks and months to confirm or refute these preliminary findings.

Specific Workscope Requested By Transocean

(as per e-mail from Perrin Roller on 2nd June, 2010)

- Forensic look back at the cement design utilized
- Review and comment on the lab test results for the slurries
- Design application fit for purpose?
- Recommendations for future cementing operations in similar situations
- Wellbore preparation prior to cementing (evaluation of what was done and recommended best practices)
- Mechanical considerations for float eq and plugs.
- Any other areas that we have not addressed

Background

Macondo is a deepwater oil and gas field located at a water depth of around 5000 feet in the Gulf of Mexico. The Macondo-1 exploration well was drilled to a measured depth of 18,360 ft (18,349 TVD) and cased and cemented with 9 pipe strings. The conductor casing was driven while the cemented strings consisted of 2 primary casings and 5 liners plus the final casing, the ill-fated 9 7/8" x 7" casing tapered longstring. This review considers only the latter since no detailed operations information was provided for the previous cementing operations.

Bottom hole static temperature, even at a depth of 18000 ft, is relatively low, being in the range of 210 deg. F but this is not uncommon in deepwater scenarios. Circulating temperature is also a relatively cool 135 deg. F.

Deepwater wells usually exhibit rather narrow pore pressure/fracture pressure envelopes, complicating the drilling and cementing process and the Macondo well was no exception. This problem can be managed in most wells but it requires careful planning and attention to detail. It may also dictate variations in the original drilling plan and requires numerous contingencies in response to actual well conditions encountered during drilling. Finally, deepwater well construction often requires non-standard approaches to cementing including, for example, the use of lightweight cement slurries in what could be regarded as unconventional circumstances.

Review of Cement Job Designs

Cement has multiple functions in an oil and gas well. The most important objective of any primary cement job is to provide a competent annular seal, ensuring that formation fluids are contained at their respective depths until deliberately produced, if required, by perforating. Cement is used to cover and isolate each individual producing interval, maintaining zonal isolation between each and providing a competent barrier between these zones and the surface This zonal isolation and pressure integrity should be maintained over the entire life of the well. No fluid movement, either gas or liquid should be possible at any time through the cemented annulus. In fact, the cemented annulus should, at a minimum, present a barrier to vertical fluid movement equivalent to the original barrier presented by the layers of rock that were removed in the process of wellbore construction. This is particularly important when the cemented annulus provides direct communication between a hydrocarbon reservoir and the surface.

In the annulus there are three possible paths for fluid movement; the interfaces between cement/rock and cement/casing and the cement matrix. Poor mud removal is normally identified as the major source of communication problems, although poor bonding at the interface can occur even when mud cake or oil films have been completely removed.

Cement bonding can also be affected by slurry properties like fluid loss and free water. However, cement adherence to the formation and casing is primarily affected by cement shrinkage and by stress changes induced by downhole variations of pressure and temperature. These occur mainly inside the casing but can also originate in the formation.

Early strength development and rapid permeability decline are important to ensure structural support to the casing and hydraulic/mechanical isolation of downhole intervals, respectively. Delays in strength development cause significant amounts of lost time due to the need to Wait-On-Cement. Thus, drilling operations cannot proceed and the rig must sit idle until the cement is deemed strong enough to continue. In deep water operations, where rig costs are high, this is viewed as particularly significant.

The actual development of strength in cement systems is dependent on a number of factors. The type of cementitious material is important due in part to chemistry and in part to granulometry. Slurry density is considered critical - lower density has, traditionally, been associated with lower strength due to dilution effects and replacement of cementitious material with additional water or inert solids. Temperature is a key parameter and, to a lesser extent, the pressure. Less appreciated, is the influence of the many types of additives that are included in slurry formulations. Correct selection of cement and additives allows slurry tailoring to achieve a "strong cement" that will support the mechanical stresses that occur during ongoing drilling operations and throughout the well's productive life. Since cement is normally the primary means of isolation, its integrity as a sealing material should be paramount.

Actual Cement Design

The cement slurry system proposed for this casing was a foamed cement design. This was based on the use of a 16.74 ppg (lbm/gal) Class H cement base slurry foamed to around 14.5 ppg using nitrogen gas. A small volume (~4 bbls) of unfoamed base slurry was to precede the foamed cement and the program also specified the use of 7 bbls of the same unfoamed base slurry to complete the job. The latter was certainly intended to fill the shoe track and provide higher density, stronger cement at the bottom of the well.

Foamed cements are not new and have been used on literally thousands of oil and gas well cement jobs around the world over the past 30 years. They are particularly popular in deepwater cementing applications because of several desirable characteristics. These include their relatively favorable setting behavior and early strength development at the low temperatures typically seen in deepwater wells, particularly in the shallower casing strings. They are also relatively flexible, less prone to tensile failure, provide good thermal insulation and, prior to setting, they are somewhat compressible. This latter property is generally accepted to provide some protection against gas migration, a phenomenon associated with the undesirable movement of hydrocarbon gas through the cement, during the actual cement setting process – the so-called liquid:solid transition.

So, while it is relatively unusual to use foamed cement for a production casing scenario, it is not unprecedented and there are several factors in this well that may, superficially at least, have supported the proposal to use it. The perceived need to use a lightweight slurry due to a narrow pore/frac pressure window is one reason. So, too, is the risk of gas migration and the desire to have a lightweight cement with good mechanical properties. However, it should be noted that these factors do not make the use of foamed cement mandatory. Even if a lightweight cement system was considered essential (which it was not, in my opinion, given the decision to pump such a small volume of cement), there are several alternative types of lightweight cement system that could be employed here in place of foamed cement. The fact that the Deepwater Horizon already had the necessary equipment onboard to perform foamed cementing may have played a role in the decision, as much as anything else. In such situations, with experienced crew who are well-versed in the technology, foamed cementing is relatively easy to perform and can offer certain advantages, particularly in terms of logistics, over other competing lightweight cementing technologies.

Having said all of the above, however, laboratory testing of the cement system for the intended application was inadequate, given the critical nature of the cement job. Laboratory results were inconsistent and should, at the very least, have called for repeat testing. Compressive strength tests on the Foamed Cement (14.5 ppg) suggested that it remained unset until sometime in excess of 24 hours. Ultrasonic Cement Analyzer (UCA) data was presented for the base slurry (16.74 ppg) showing reasonable strength of 500 psi after only 6 hours. The test methodologies and temperatures employed are different but such a vast discrepancy in the appearance of set characteristics should have raised some concerns. Were all additives included in both designs? Was the foaming agent actually used in the base slurry tests?

Similar questions can be raised on the thickening time tests which again were performed on the base slurry and showed reasonable setting times. Testing the base slurry for thickening time is an accepted practice yet, despite the addition of some extra retarder to further lengthen the thickening time, no additional new data were generated for compressive strength or slurry rheologies. The latter, incidentally, showed hallmarks of an unstable slurry – one that may be prone to settling or Free Water, based on the Fann data presented for both mixing and bottom hole rheologies.

Surprisingly, no Fluid Loss Control data were presented for this slurry, perhaps because it contained no specific additives to control fluid loss. This is surprising. Fluid loss control is generally considered to be essential in any slurry that is used to control gas migration and while foamed cement has better leak-off characteristics (and higher compressibility) than normal cement, fluid loss must still be minimized to prevent premature depressurization. In fact, it is widely accepted that fluid loss control in slurries for gas migration prevention should be <50 mL/30 mins (or even lower, at <30mL/30mins).

Finally, no data are presented for gel strength development of this cement which, again, is surprising since Halliburton largely championed the idea of using gel strength to counteract gas migration. In fact, it is surprising only until one looks at the conditions immediately after cement placement. The so-called Critical Static Gel Strength, which is defined as the gel strength value at which the cement slurry becomes sufficiently self-supporting that it nullifies overbalance pressure on the active (gas) zone, could, quite conceivably, have only been measured in minutes for this well with this slurry, under these conditions.

Cement Distribution in the Annulus

Assuming the wellbore geometry is known within reasonable limits, it is normally relatively easy to calculate cement fill in the annulus on the basis of simple volumetrics. Exceptions may arise, however, in cases where losses have occurred or large percentages of mud are bypassed during the cement placement. The former occurs when circulating pressures exceed formation fracture pressure; the latter when cement fails to displace mud from washouts or where substantial channels remain in the cement due to poor mud displacement.

In the specific case of the 9 7/8" x 7" casing cementation, a 4-arm caliper was available to provide a fairly accurate assessment of wellbore geometry and, by extension, a good estimate of hole volume. Normally, this is a prerequisite for foamed cementing, especially in a small annulus, since foam volume is dependent on pressure. Thus, a foam that is raised in the annulus higher than planned is subjected to less hydrostatic pressure and expands, reducing its own density and exerting less pressure on foamed cement beneath it, which also expands, and so on. It must be noted, however, that in the Macondo well, this is not quite so critical due to the already high pressure at such depths. Thus, the density change caused by bringing foam cement 200 ft higher than expected at this depth (unlikely) would only be about 1 percent.

Thus, based on the job design employed, the top of cement (TOC) was calculated to be at a depth of 17300 ft. The MI-Swaco report records no incidence of either losses or flow, immediately prior to, during, or subsequent to the cementing operation. This suggests that operational aspects of the job were within acceptable limits and there were no obvious incidents that may have predicted anything other than a normal cement job.

However, this begs the question: Why was it decided to leave a part of the open hole uncemented, especially since this annulus was in direct communication with surface?

Coverage of All Active Zones

Clearly, to ensure adequate isolation, it is imperative that competent cement covers all active zones, particularly if such zones have higher pore pressures, exhibit moderate to high permeability or may be prone to losses. The primary reservoir intervals in this well (as far as I can ascertain) were at a depth of approximately 18,200 ft. However, it should also be noted that there is mention of an active zone (pore fluid composition unknown) much further up the hole at xxxxx ft.?????

Vertical Height of Cement Above Uppermost Active Zone

While cement is generally regarded as a reliable and cost-effective sealant, it is also recognized that it is not perfect for such applications and that its placement cannot be guaranteed with absolute accuracy. Accordingly, rules-of-thumb have evolved over the years to account for such imperfect material properties and uncertain displacement mechanics, especially for critical cement jobs and for those where problems like gas migration are anticipated. These rules-of-thumb mostly specify the minimum length of cement that should be placed above the uppermost active zone in a given well segment. Some cementing service companies use values of 500 linear feet of cement while others may specify 200 linear meters, underlining the empirical nature of such guidelines. In the Macondo well, this general guideline was respected although it was done with a cement slurry that was probably not ideal for zonal isolation and without the benefit of additional mechanical seals that would have provided additional levels of security.

Overbalance Pressure (OBP)

With very few exceptions, wells are drilled with muds that exert hydrostatic pressures in excess of formation pore pressures, to ensure well security and control. The excess is referred to as "overbalance pressure" (OBP). In addition, under circulating conditions, while drilling or cementing, for example, fluid friction pressures exert additional backpressure on the well and the total pressure acting on active formations may be expressed as the sum of both, converted to an equivalent pseudo-hydrostatic fluid density. This is referred to as the Equivalent Circulating Density, or ECD. Generally, absolute hydrostatic density of the fluid column (when static) must always exceed formation pore pressure, providing a safe OBP of 200-300 psi (or greater). ECD, on the other hand must not exceed the formation breakdown pressure (frac pressure), as determined by fluid leak-off tests or other techniques. Exceeding frac pressure can induce mud losses that can, in turn, compromise well security if the losses are left unchecked.

In general, the cementing operation increases the risk of losses because cement spacer density and cement slurry density are traditionally greater than original mud density and friction pressures may also be higher, resulting in both elevated hydrostatic pressure and elevated ECD. While this may make job execution more difficult when weak formations are present, the additional OBP afforded by the heavier spacer and cement (compared to mud) provides additional protection from fluid invasion and gas migration once the cement is in place (assuming no losses, of course). Unfortunately, in the Macondo well, the choice of cement design left the well extremely vulnerable to gas invasion and very poorly protected once the cement sheath had been compromised. The OBP on the gas zone, immediately post-placement was only around xxx psi due to the use of a lightweight foamed cement and the problem was exacerbated by lowering the TOC into the open hole. NOTE – I am waiting for the exact pore/frac pressure data here but, by everything I can see, the OBP was unacceptably low.

Barriers to Flow

Given the nature of the hydrocarbon fluids produced by the oil and gas industry, it makes sense not to rely on a single barrier between active formations and surface to prevent flow or uncontrolled escape of hydrocarbons. Thus, it is a requirement to ensure that at least two competent barriers must lie between a hydrocarbon zone and the surface. During drilling the mud column and the BOP stack constitute two barriers although, in deep water, the use of a marine riser makes this situation less secure than normal, in the event of an emergency disconnect, for example.

In the case of the Macondo 9 7/8" x 7" production casing, the planned annular barriers consisted of the cement and the casing hanger seal at the wellhead.

Mud Displacement

Where cement is the primary sealant (as in most oil and gas wells), effective zonal isolation requires complete mud displacement. Unlike cement, drilling mud does not normally set and channels of mud remaining in the cemented annulus can act as conduits for reservoir fluids, compromising the cement seal. Furthermore, mud and cement are often incompatible and contact between the two may produce undesirable effects. Both mud and cement may gel to produce a viscous, unpumpable mixture or additives in the mud may contaminate the cement and either delay setting and reduce compressive strength or, perhaps, cause a premature set.

In order to avoid such problems and provide a high probability of achieving competent zonal isolation, a variety of measures are usually undertaken prior to, and during, the cementing operation. These include:

- Pipe Centralization
- Mud Circulation and Conditioning
- Use of Spacers/Flushes
- Ensuring Fluid Compatibilities
- Optimizing Placement Rates

Each of these is discussed in greater detail, below.

Pipe Centralization

Casing centralizers have been in use for many years but they are still regarded by many as unnecessary pieces of casing jewelry. They have been criticized for causing problems in getting casing to bottom and stories abound in the industry of more centralizers ending up on the sea bed than on the casing string.

In reality, centralizers are an important part of any primary cement job and, in some cases, they are absolutely essential, defining the difference between success and failure of the operation. While it has long been recognized that poorly centered pipe may compromise full cement coverage in the annulus, it is still generally not appreciated just how critical is the effect of eccentricity on the cementing process. By definition, a perfectly centered pipe in a perfectly gauge hole is referred to as having 100% stand-off. A pipe that lies against one side of the borehole, in contact with the formation (or the inside of another casing), is referred to as having

0% stand-off. Intermediate conditions, expressed as percentages, lie between these two extremes.

In the case of 7" pipe in 8 ½" open hole, movement of the pipe by a mere ¼" from the center line of the well axis, reduces the stand-off from 100% to a mere 67%. The net effect of this apparently minor deviation of the casing towards one side of the wellbore has profound effects on fluid velocities in the annular space around the pipe. Fluid being circulated through the well will now favor flowing on the wider side of the annulus and the fluid velocity on that side will also be faster. This leads to a separation of the leading fluid interfaces with the fluid on the narrow side trailing behind that on the wide side. The effect can be very significant, extending tens or even hundreds of feet. In the case of non-Newtonian fluids, especially those like muds that possess gel strength, it may be impossible to get them to flow on the narrow side of the annulus at all. In such a scenario, a portion of the annulus may be left with a long gelled stringer of mud on the narrow side. Thus, poor centralization sets up conditions for poor mud displacement and predisposes towards channeling in the annulus.

Pumping the displacing fluid in turbulent flow can reduce this effect somewhat but it is important to note that the geometry of an eccentric annulus requires much higher pump rates to achieve turbulence compared to the fully-centered case. In order to achieve turbulent flow in an annulus with 67% stand-off, we would need to pump at twice the rate that we would require in the 100% stand-off case. Such rates are normally impractical to achieve or would increase the risk of causing other problems, like lost circulation. In such circumstances, the best solution is to physically move the casing throughout the cementing operation, either by reciprocating or rotating the pipe. Moving the casing acts to break-up gelled mud and improve the flow distribution in the annulus.

Mud Circulation and Conditioning

After drilling a section of hole through the reservoir section, it may be some considerable time before the well is cemented. Retrieval of the drill-string and BHA, open hole logging operations and the time needed to run casing, especially in a deep well, can mean that the mud in the well remains quiescent (or at least not actively circulated) for a prolonged period of time. Drilling mud is naturally thixotropic and tends to build gel strength if left undisturbed for a time. It is quite common in such circumstances for hydrocarbon gas to invade the mud column adjacent to the reservoir and it is normal recommended practice to circulate the mud in the well when the casing string has been run to TD and the well is being prepared for cementing. This procedure breaks the mud gel strength and ensures that the mud in the well is mobile while also bringing any small volumes of gas that may have invaded back to surface. If large volumes of gas are detected, this may be an indication that the margin between mud hydrostatic pressure and reservoir pore pressure is insufficient or that the mud exhibits excessive thixotropy.

As with many oilfield procedures, the amount of time spent circulating the mud in the well prior to cementing is not hard-and-fast and depends on many factors. General guidelines, as provided in documents like API-65, are often followed unless there are specific reasons to deviate from such procedures. Typical practices include circulating the mud from the bottom of the well back to surface (bottoms-up), circulating one and a half annular volumes or one casing volume (whichever is greater) or circulating the entire contents of the well. Additional procedures may involve running so-called fluid calipers to establish what proportion of the mud is actually mobile and being circulated. A fluid caliper uses a marker of some type in the mud and involves the pumping of at least one entire well volume. The time taken to recover the marker multiplied by the pump rate provides an indication of the volume of mobile mud and this is compared with the theoretical hole volume. The procedure may be carried out more than once or at more than one rate to gauge the impact of rate on circulation efficiency.

Mud has many functions in an oil and gas well. Apart from providing hydrostatic overbalance to prevent unwanted flow from subsurface strata, it also acts as a connection between those strata and surface. Pit losses or gains indicate changes in well stability and they alert personnel of the need to make adjustments to fluid densities or circulation rates, etc. The mud also acts as a lubricant, helping to cool the bit, and as a transport medium, carrying rock cuttings from the bottom of the hole to surface. This capacity to lift cuttings is no longer necessary when cementing operations commence, particularly on a production string, and, in fact, this property of the mud makes it more difficult to remove from the well. As a consequence, it is routinely recommended by industry guidelines, in general, and cementing service companies, in particular, that mud should be thinned or "conditioned" prior to cementing. It should be noted, however, that while this is widely recognized as beneficial it is not consistently done, at the level of field operations, due to the perception that it represents unnecessary time and expense.

Use of Spacers/Flushes

As noted above, mud and cement are usually incompatible, often combining to form viscous mixtures that are difficult to displace from the annulus and that do not provide an adequate wellbore seal. For this reason, fluids called "spacers" are typically pumped ahead of the cement slurry (and sometimes behind it, too), to provide a buffer between the mud and cement. Spacers, therefore, may be considered as specially designed, weighted fluids that are pumped to remove the mud while maintaining hydrostatic pressure control in the well. Spacers must be compatible, rheologically, with both mud and cement so that intermixing does not cause any unpredictable viscosity changes during the displacement process. Ideally, the spacer should completely displace all mud from the annulus in the section to be cemented, ahead of the cement slurry's arrival, thereby ensuring that mud and cement never contact one another. It goes without saying that the spacer itself (and any mixtures of spacer with mud) should remain fluid and very easy to displace from the annulus by the cement slurry, if we are to ensure good zonal isolation.

In wells drilled with oil-based muds, or synthetic oil-based muds as in the Macondo case, there are additional challenges. Such muds have oil as the external phase and they tend to oil-wet surfaces that they contact, including both the wellbore and the casing. Unfortunately, cement does not bond well to such oil-wet surfaces so, in order to ensure good adhesion and bonding between the cement and these surfaces, it is necessary to water-wet them. This is normally accomplished by incorporating a water-wetting surfactant in the spacer. The surfactant removes the oil film ahead of the cement slurry's arrival and leaves all contacted surfaces water-wet.

With heavier oil-based muds, the high concentration of fine oil-wet solids in the mud (organophilic clay, barite, calcium carbonate, drill solids), increases the risk of incompatibility between even the mud and the spacer. This problem can generally be solved by pumping a "flush" which consists of a small volume of solids-free "base oil" (ie. the oil component of the mud), ahead of the spacer. This acts to dilute the mud, reducing its viscosity by reducing the solids concentration at the critical interface between mud and spacer. It is, of course, important to minimize the volume of flush, particularly in a small annulus. Otherwise, well security may be compromised by the reduction in hydrostatic pressure that the solids-free, low-density flush causes in the well.

The volumes of spacer/flush that must be pumped to ensure complete mud removal vary from well to well. They are dependent on many factors, including mud/spacer/cement rheology, fluid densities, hole geometry, casing standoff and pump rate. However, a general rule-of-thumb, based on experiment and many years of field cases, calls for the pumping of sufficient wash/spacer to provide 10 minutes of contact time. Thus, at a displacement rate of 4 BPM, the minimum volume of flush/spacer required would be 40 barrels; at 6 BPM it would be 60 barrels. This should be viewed as a minimum criterion and, where possible, it would generally be beneficial to pump more spacer than this simple calculation suggests.

Ensuring Fluid Compatibilities

As noted above, it is important that spacer fluids be compatible with both mud and cement. Test methods are described by API/ISO specifically for the testing of mud/spacer/cement compatibility and these are widely used. Unfortunately, no laboratory data were provided by Halliburton on fluid compatibilities, suggesting that these tests were not performed. However, it must be said that these tests are time consuming and do not always provide useful information, especially when the operation is offshore. The results are only strictly applicable if representative samples of the drilling fluid (containing all the drill solids, etc) are used and the latter may not be available in a timely manner. As a result, they are not used consistently by every service company for every cement job.

Optimizing Placement Rates

It has long been recognized that pump rate is important in the mud displacement process. Higher rates generally favor mud displacement by providing energy in the form of pressure drop and it is this pressure drop that drives the displacement process. Particularly when displacing thixotropic muds, the shear stress developed by the displacing fluid must exceed the yield point of the mud if it is to put the mud in motion and displace it. This is only one of several criteria that must be met to guarantee effective displacement in the absence of pipe movement. The latter, incidentally, greatly assists the displacement process but is disliked by many industry veterans for fear of sticking pipe or having other mechanical problems.

Industry guidelines support the use of turbulent flow for cementing operations since it provides higher pressure drops and a flatter average velocity profile, reducing channeling and improving displacement. Unfortunately, it is difficult to achieve turbulent flow in many circumstances due to higher circulating pressures and the risk of formation breakdown (losses) while circulating at high rates. Also, as mentioned above, even slight eccentricity of the annulus, due to casing being poorly centralized in the borehole, can require unrealistic pump rates to achieve turbulence.

Mud Displacement - Summary

Displacing all the mud from an interval in a deep well and replacing it with cement to ensure zonal isolation is not a simple task, given the constraints mentioned above. In general, however, using a combination of the techniques mentioned and following widely accepted industry practices provides good results in the vast majority of cement jobs. This has been verified by numerous studies over many years.

Cement Wiper Plugs and Cement Float Equipment

Some concerns have been raised about the ability of cement wiper plugs to transit the tapered string and actually do the job they were intended to do – separate the cement from the spacer and mud and wipe the interior surface of the casing string. However, all indications from the actual job are that these plugs functioned, as planned. There were clear pressure indications as they passed through the 9 7/8" x 7" x-over and both plugs bumped at the float collar. Furthermore, proprietary data from tests conducted in the past, indicate that this should not be a cause for concern.

Questions were also raised regarding float equipment and the difficulties in converting the autofill equipment prior to cementing. Suspicion was cast on the fact that the double-flapper valve may not have been sealed or that it was somehow left partially open during pressure testing, perhaps at a time when cement may not have been completely set. However, it must be said that, despite difficulties and multiple attempts, the float conversion was indeed finally accomplished and all indications were that the floats held, despite lower than normal differentials between the annulus and the inside of the casing.

Conclusions

Appendices: