SPECIAL CONSIDERATIONS IN CEMENTING HIGH PRESSURE HIGH TEMPERATURE WELLS.

Prisca Salim
Mahmood Amani

Texas A&M University Qatar
mahmood.amani@qatar.tamu.edu

Abstract

Growing demand to drill High Pressure High Temperature (HPHT) wells push the limit of existing technology to overcome their challenges. Case study of the Montara well blowout 2009 and Gulf of Mexico 2010 showed one of the main contributing factors to failure the well in both cases was substandard cement job. The 2012 HPHT Wells Summit board meeting in London in October 2012, gathered to share their insight and case studies from operators of HPHT wells. From the meeting it was mentioned the result of a survey sent to HPHT professionals who majority from drilling department picked out Cement Design as the third most concerning technology gap for HPHT operations (15%). Whereas in Figure 1, 23% said Seal is the biggest technology gap for HPHT operations, 16% for Testing, 16% for Safety Measures, 12% for Polymer and metallurgy, 8% for Casing, 6% for Tubular, and 4% for other challenges such as drilling equipment, Mud, MWD/LWD tools temperature limitation, and seismic resolution. Even in 2010 HPHT Wells Summit Annual meeting, the survey that appears in Figure 2 showed majority of professional choose Cement Design as the biggest technology gaps for HPHT operations.

This paper provides a review of some of the best practices and case studies in the area of HPHT cementing. The objective is to underline some important consideration related with designing cement for HPHT wells. This paper will serve as a guide for the engineers, researchers and other HPHT professionals to improve cement design and
gives an insight to some anticipated problems that may arise due to high temperature or high pressure or sometimes both extreme conditions. This research elaborates on the Design, Execution and Evaluation phase, and discusses some Crucial Problems in HPHT cementing and provides some Recommendations and Conclusion.

Keywords: High Pressure high Temperature, cement design, MWD/LWD tools temperature limitation, and seismic resolution

**Introduction**

During the past decade, the number of HPHT projects has increased. The main HPHT areas are found in the United States (Gulf of Mexico), Indonesia, North Sea, Norwegian Sea and Thailand. Some of the thermal recovery projects are located in Canada, California, Venezuela and Eastern Europe (Figure 3).

![Figure 3. HPHT Projects around the world (Schlumberger)](image)

Many of the oil and gas resources are located in deeper formations. This provides a wide range of difficult challenges and mechanical issues. One of these issues is the negative impact on cement’s rheological properties when exposed to high pressure high temperature conditions, which are common in deep drilling. The most common HPHT definition is when bottom hole temperature exceeds 300°F (150°C) or bottom hole pressure exceeds 10,000 psi (69 MPa).

High temperature gives a sensitive effect to the cement slurry, especially to the thickening time. It will reduce the thickening time which could set the cement quicker compared with average temperature wells. The high temperature also could affect the cement rheology. The Plastic Viscosity and Yield Point will decrease with an increase of temperature (Ravi and Sutton 1990).

High pressure requires the drilling engineer to be very selective in determining a correct weight to overcome small equivalent circulation density window. Cement weight should withstand the formation pressure by creating minimum overbalance. As increasing curing pressure, an earlier compressive strength development and higher
ultimate compressive strength are observed to result from the high pressure.

As the well depth increases, hydrostatic pressure will increase as well as the ECD (Equivalent Circulating Density) and vice versa as rise of temperature will reduce ECD due to thermal expansion. In HPHT wellbore, it’s suspected to have high-temperature variation which will give effect to expansion and contraction of casing and plastic formation it will lead to crack in set cement (Elzeghaty et al. 2007). Cement physical and chemical behavior changes significantly at elevated temperatures. Cementing in high-temperature environment is encountered in three principal types of wells; deep oil & gas well, geothermal wells and thermal recovery wells (Nelson 2006).

**Design**

Drilling with high temperatures, high pressures, narrower annulus, and sometimes corrosive fluids are often found in High Temperature High Pressure wells. Therefore, the cement design should consider a combination between silica, retarders, weighting agent, extender, expanding additive, fluid loss agent, casing eccentricity, mud removal and laboratory test, which lead to the original objective to provide complete isolation in the proper zone over the life of the well. For the time being silica stabilized Portland cement is still in use for HPHT oil and gas wells.

**Cement type for high temperature or high pressure well**

For the last 50 years, the most commonly used cements for thermal well have been Portland cement, Silica-Lime system, and High-Alumina cement. Table 1 presents Cement class standard specification, some information taken from Nelson 2006.

<table>
<thead>
<tr>
<th>Class</th>
<th>Depth (ft.)</th>
<th>Temperature (°F)</th>
<th>Purpose</th>
<th>Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>0 – 6,000</td>
<td>80 - 170</td>
<td>Use when special properties are not required.</td>
<td>O</td>
</tr>
<tr>
<td>B</td>
<td>0 – 6,000</td>
<td>80 - 170</td>
<td>Moderate or high sulfate resistance.</td>
<td>MSR and HSR</td>
</tr>
<tr>
<td>C</td>
<td>0 – 6,000</td>
<td>80 - 170</td>
<td>High early strength.</td>
<td>O, MSR, HSR</td>
</tr>
<tr>
<td>D</td>
<td>6,000 – 10,000</td>
<td>170 – 290</td>
<td>Retarder for use in deeper well (High temperatures &amp; high pressure).</td>
<td>MSR and HSR</td>
</tr>
<tr>
<td>E</td>
<td>10,000 – 14,000</td>
<td>170 – 290</td>
<td>For high pressure and temperature</td>
<td></td>
</tr>
<tr>
<td>F</td>
<td>10,000 – 14,000</td>
<td>230 – 320</td>
<td>For extremely high pressure and high temperature.</td>
<td>MSR and HSR</td>
</tr>
<tr>
<td>G</td>
<td>All depths</td>
<td></td>
<td>Basic well cement (improved slurry acceleration and retardation).</td>
<td>HSR</td>
</tr>
<tr>
<td>H</td>
<td>All depths</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>J</td>
<td>All depths</td>
<td>&gt;230</td>
<td>For extremely high pressure and high temperature.</td>
<td></td>
</tr>
</tbody>
</table>


Table 1. Cement class standard specification

**Portland cement chemistry**

Portland cement is a calcium silicate material, most components being tricalcium silicate (C₃S) and dicalcium silicate (C₂S). With addition of water both hydrate to form a gelatious calcium silicate hydrate called “CSH phase”, it’s an early hydration product and excellent binding material at well temperatures less than 230°F (110°C). In high temperature, “CHS phase” will decrease compressive strength and increased permeability of the set cement. Swayze (1954) describes this phenomenon as *Strength Retrogression*. At temperatures above 230°F conventional Portland cement system gives significant loss of compressive strength occurred within 1 month, the levels to which the compressive
Strength are sufficient to support casing in a well should be considered. The main problem is a serious permeability increase, within one month the water permeabilities of the normal density class G cement were 10-100 times higher than the recommended limit (0.1 mD). High-density Class H permeability was barely acceptable. The Compressive strength and permeability behavior of Portland cement at elevated temperature is presented in Figure 4.

![Figure 4. Compressive strength and permeability behavior of Portland cement at elevated temperature (Eilers and Nelson 1985)](image)

Strength retrogression can be prevented by reducing the bulk lime silica ratio (Menzel 1935, Kalousek 1952, Carter and Smith 1958). In Portland cement, it could be replaced partially by fine silica sand or silica flour. At 230°F by adding 35-40% silica BWOC (By Weight of Cement) it will reduce cement silica ratio and at this level tobermorite is formed which preserves high compressive strength and low permeability. As the curing temperature increases to 300°F, tobermorite normally converts to xonotile & gyrolite which lower cement deterioration of cement performance. Normal density class G cement which stabilized with silica was cured at 446°F and 608°F.

At 480°F, truscottie begins to appear, curing temperature approaches 750°F and at high temperature resulting disintegration of cement set. Cements containing significant amounts of truscottite are usually characterized by low permeability (Gallus et al. 1978). In general, set cements that consist of cement silica ration less than or equal to 1.0 tend to have higher compressive strengths and lower water permeability. Nevertheless, cement set not only depends on down hole temperature, but also the presence of other minerals, its composition can evolve as down hole conditions change.

Well cements are permanently exposed to downhole conditions. Above 230°F, commonly used Portland cement may shrink, lose strength, and gain permeability. This deterioration can be minimized or even prevented by adding at least 35% silica by utilizing cements engineered for the HPHT environment. Even if zonal isolation is initially adequate, changes in downhole temperature and pressure can crack or even shatter the cement sheath; radial pressure/temperature fluctuations can create a microannulus. Problems like this one are crucial in hot deep wells. High temperature flexible cement has a lower Young’s modulus so it is flexible and can expand more after setting, which will strengthen the bond between the casing and the formation. High temperature cementing jobs are generally performed with API Class G or Class H cement. In a published case history for an HPHT field in Northern Italy, for the HPHT slurries, they used a combination of Class G cement with 40% silica flour, and it provided excellent oilfield retarders and prevented mechanical
strength retrogression (Frittella, Babbo and Muffo 2009).

**High Alumina Cement**

High Alumina cement is used because it can withstand wide ranging temperature fluctuations. Figure 5 presents the effect of curing temperature at high alumina cement extended to 70% crushed firebrick (Heindl and Post 1954). From 1,022°F to 1,742°F a recrystallization occurs. The strength and durability of high alumina cement between 440°F to 1830°F are controlled by the initial water to cement ratio. The amount of added water should be a minimum to prepare the slurry. At least 50% of the solid should be cement. Dispersant is helpful for pumpability of the slurry.

![Figure 5. Compressive Strength of High Alumina Cement crushed firebrick concrete after 4 months exposure from 68°F to 2,190°F (Heindl and Post 1954)](image)

Silica sand should not be used if temperatures exceeding 572°F because of the change in crystalline structure, thermal expansion is relatively high at these temperatures and thermal cycling could eventually disrupt the cement. The most commonly used extender high alumina cement is crushed aluminosilicate firebrick, other suitable materials such as calcined bauxite, certain fly ashes, diatomaceous earth and perlite.

**Class J Cement**

Class J cements was developed in the early 1970s for cementing wells with static temperatures above 260°F (Maravilla 1974, Degouy and Martin 1993, Bensted 1995). Class J cements is similar to Portland cement. It is a calcium silicate material but no aluminate phase. Since it has low usage, currently class J cement is not in the API cement list, however it’s still used mainly for geothermal well applications. A similar cement known as belite silica cement has been used in the high temperature well cementing (Bulativ 1985). It is very useful because addition of silica is not required and retarder is not necessary for circulating temperatures less than 300°F. Cement silica ratio of class J cement is adjusted and obtained upon curing.

**Retarder (Thickening Time)**

HPHT wells are wells where pressure exceeds 15,000 psi and temperature exceeds 300°F respectively and usually located at depths greater than 15,000 ft. (Ogbonna 2010). It is usually designed to have at least 3 to 4 hours cement slurries pumping time. In such deep wells, differential static temperature between top and bottom of cement column can exceed 100°F. Small temperature difference, even as small as only 10°F, can cause significant changes in thickening time. Retarder has varying sensitivity levels, especially to the temperature. Proper amounts of Retarder must be blended into the cement system. If it is too much it will cause long waiting on cement and in high pressure wells may lead the entry of gas into the cement. It’s important to have good relation between additives and cement and to have a good result a lignosulphonate high temperature retarder or...
synthetic high temperature retarder is usually used (Frittella, Babbo and Muffo 2009). On the extreme temperature, thickening time was measured initially with ± 10% of the retarder concentration (North, Brangetto and Gray 2000).

In high pressure wells, with increasing curing pressure, a significant accelerating effect is observed (Beardne 1959). Earlier compressive strength development and higher ultimate compressive strength have also been seen (Handin 1965, Metcaf and Dresher 1978). Figure 6 shows a significant accelerating effect is observed upon rising pressure.

Weighting Agent

It is crucial to maintain hydrostatic pressure in the well to balance or exceed the formation pressure. For deep wells mud weight ranging from 15 lbm/gal to 27 lbm/gal (Nelson & Guillot 2006) are typically required to overcome this matter, cement slurry with density over 16.5 lbm/gal require a weighting agent. White powdery Barite is available at most oilfield locations. It has a specific gravity of 4.33, and additional water is required to wet its particles. Slurries with densities up to 19.0 lbm/gal can be prepared with Barite. Red crystalline granules Hematite is very efficient weighting agent, it has 4.95 specific gravity and could overcome many of the shortcomings of barite. Dispersant is often used to prevent excessive hematite slurry viscosity. Hematite used to prepare slurries with density as high as 22 lbm/gal. Reddish-brown powder Manganese Tetraoxide is a very small size particles (average 5µm) has 4.84 specific gravity, significantly greater particle surface area then other weighting agent, provide a better mix, especially when well control is one of the issues. It has fewer tendencies to settle than hematite and can be added directly to the mix water (Johnston and Sense 1992) without severe settling. Combination between hematite and manganese tetraoxide can be prepared to have slurries densities as high as 22 lbm/gal. Slurries containing manganese tetraoxide typically develop higher compressive strength than other weighting materials, but sometimes with shorting thickening time. Physical Properties of weighting agents presented in Table 2 (Nelson and Guillot 2006).
Large quantities of weighting materials can lead to slurry sedimentation. By using multi particle size distribution or dry blended weighting agent to cement bulk will minimize the concern. On the other hand, dry blended weighting agent in cement bulk can cause to vary dry blend mixture, also the mixture powder should be sent to the cement unit, makes density of cement slurry to be inconsistent. Too much weighting material can cause viscous slurry properties, which can cause a decrease in cement compressive strength.

### Extender

In HPHT condition prevent lost circulation or breaking the formation is not uncommon, sometime low density slurries or raising slurry yield are required to prevent these problems. Extenders such as flyash, bentonite, prelite are commonly used to overcome these matters. In experiments at a temperature of 450°F and 600°F Fly Ash was the heaviest 15.6 lbm/gal, has the highest density and initial compressive strength and over 24 months their compressive strength starts to degrade. Bentonite and Perlite have adequate compressive strength performance at both curing temperature 450°F and 600°F but the permeabilities were too high. Today Perlite is rarely used, since it compressible and could increase hydrostatic pressure. With 16 lbm/gal class J cement has adequate compressive strength at temperature 450°F and has low water permeability. The behavior of these examples illustrates that assumption that high compressive strength is linked to low permeability is not true. Figure 7 and 8 illustrated the long term performances of conventionally system that cured in 450°F and 600°F.

**Table 2.** Weighting agents physical properties for cement slurries

<table>
<thead>
<tr>
<th>Material</th>
<th>Specific Gravity</th>
<th>Absolute Volume (gal/lbm)</th>
<th>Color</th>
<th>Additional Water Requirement (gal/lbm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ilmentie</td>
<td>4.45</td>
<td>0.027</td>
<td>Black</td>
<td>0.00</td>
</tr>
<tr>
<td>Hematite</td>
<td>4.95</td>
<td>0.024</td>
<td>Red</td>
<td>0.0023</td>
</tr>
<tr>
<td>Barite</td>
<td>4.33</td>
<td>0.028</td>
<td>White</td>
<td>0.024</td>
</tr>
<tr>
<td>Manganese tetraoxide</td>
<td>4.84</td>
<td>0.025</td>
<td>Reddish brown</td>
<td>0.0011</td>
</tr>
</tbody>
</table>

![Figure 7](image1.png)  
*Figure 7. Compressive strength and permeability performance of conventionally extended Portland cement slurries 450°F (Elizers and Nelson 1985)*
The conventional extended Portland cement with density below 12.5 lbm/gal may not be able to perform suitably in high temperature wells. For cement with density below 12.5 lbm/gal may need microsphere-extended, multimodal particle size or foamed cement. Glass microspheres with hydrostatic crush strengths could hold 10,000 psi but ceramic microspheres only can withstand up to 3,000 psi (Nelson 2006), both could be used in thermal well since they stabilize in high temperatures. Apparently ceramic system appears to perform better at higher temperatures 600°F. For geothermal, steamflood wells common to use foamed cement and occasionally used in deep high temperature wells.

**Expanding Additive**

Besides proper cement placement in the annulus, strong cement-casing support and right zonal isolation are most important. One way to achieve strong cement bond between casing cement and formation is by adding expanding additive. Cement contains Manganese Oxide (MgO) provide excellent expansive performance at curing temperatures as high as 550°F and at temperature below 140°F the hydration proceeds very slow (Saidin et al. 2008). The presence of expanding additives MgO would increase the number of matrix in cement and with hydration process could cause better expend in cement. * Burning temperature* is the temperature which MgO was burnt and *conditioning temperature* is the temperature conditioned like temperatures in the wellbore (Rubiandin 2000). Figure 9 showed class G cement containing 1% BWOC MgO shows that amount of expansion increase with increasing in temperature.
Base on Rubiandini (2000) adding burnt MgO will increase shear bond stress but will reduce the compressive strength, even it is still higher than the minimum value. High burning temperature hardened the MgO, will make MgO difficult to react with cement (for the same conditioning temperature, the value of shear bond strength and compressive strength reduce accordance with the rise of burning temperature). High conditioning temperature was increase the reaction velocity of MgO (for the same burning temperature, the value shear bond strength and compressive strength increased accordance with the rise of conditioning temperature). Pure MgO which is burnt at 1,832°F to 2,552°F are capable in increasing shear bond strength up to 300%. For high conditioning temperature 300°F to 400°F using 2200°F burnt MgO are convenient. At conditioning temperature higher than 300°F show better performance, on the other hand, burnt pure MgO at 2,552°F show dissatisfied result. The effective expanding additive concentration for increasing shear bond strength is ranging from 5 to 10%.

**Fluid Loss Agent**

Maintain constant fluid loss in the deep well is necessary to preserve the chemical and physical characteristic of the cement slurry, especially due to differential pressure on top and bottomhole in a long or deep well. On the other hand, it needs to prevent the development of filter cake that could cause bridging in the annulus. It would likely occur in long string casing, especially in deep well cement, narrow clearance between wellbore and liner might, fluid loss would be crucial. Effect of temperature and fluid sequence to fluid loss is presented in Figure 10.
Too much fluid loss may provide space for the gas to get into the cement slurry in the annulus. Fluid Loss agent used to prevent early slurry dehydration for HPHT cementing operation. The design criteria for fluid loss control are linked to dynamic filtration rather than static filtration. Maximum fluid loss rates for oil wells are 200 ml per 30 minutes and 50 ml per 30 minutes for gas wells (Hartig et al. 1983). Christian et al. 1976 and Frittella, Babbo and Muffo 2009 mentioned limit for fluid loss is 50 ml per 30 minutes. Another opinion by Dillenbeck and Smith (1997) showed that for specific gas filed no fluid-loss are necessary to get a good cement job. Thixotropic cement slurries can give high fluid loss rates, though dehydration and bridging must be considered (Pour and Moghadasi 2007).

Casing Eccentricity

Generally, 70% standoff is considered as minimum requirement to have good cement bond, casing need to keep in the center of the wellbore. For centralizer near the shoe 75% standoff is too high. The ideal wellbore is free or at least 1.5in wide washout, result of imperfections borehole making casing is never in the center of the open hole. Fluids will naturally flow more readily on the wider side of the annulus. Maintaining above 67% standoff casing centralization as per API standard was an early guideline to facilitate the displacement process. Good survey and four arms caliper are recommended to determine a proper centralizer placement in critical wells.

Increase the degree of casing eccentricity does not increase significantly on max von Mises stress in cemented wellbore casing using high-thermal property cements. But in the other hand increase the degree of casing eccentricity will increase max von Mises stress in cemented wellbore casing using low-thermal property cements. At casing eccentricity lower than 40%, eccentricity has minor effect on the casing von Mises stress. When casing eccentricity approach 90%, at wellbore angle between 30° to 50° it reached max von Mises stress 7.5E4 psi, which is 67% larger than the stress developed at the concentric condition (Yuan, Schubert, Teodoriu 2012). Casing eccentricity leads to reduce cement shear stress and tensile stress, but in the other hand it increased cement compressive stress.

Mud Removal

Mud removal planning in quantity and sequence is no less important in achieving strong cement bond and proper cement placement in HPHT wells. The plans include the conditioning of drilling fluid, preflushed, spacer and mud removal tools such as scratchers. Drilling fluid conditioning is circulated before cementing to remove gas and cuttings, break the muds gel strength and lower the mud viscosity. Chemical wash and spacer pump ahead of the slurry to act as a buffer between possibly incompatible mud and cement, around 10 minutes contact time is recommended. Difference between spacer & mud densities and cement and spacer densities should be around 10%. In Northern Italy, minimum of 262 ft./min annular velocity should be considered to get effective turbulent flow. Maintain separation from displacement to avoid slurry contamination we need at least 650 ft. of spacer Ahead and 170 ft. behind cement slurry (Frittella and Muffo 2009).

Improving pipe stand-off, increasing $\mu_p / \mu_s$, decreasing mud gel strength and increasing flow rate are an important factor to achieve a good mud removal. For Bingham Plastic fluids, the higher the dimensionless shear rate, the better circulation efficiency will be (Table 3). Base on Yetunde and Ogbonna (2011) having a minimal gel strength development, a low plastic viscosity to yield viscosity ratio PV/YP and design compatibility of drilling fluid & displacement is important in cementing. Pipe rotation and reciprocation can help to get planned flow models and recommend starting the movement during mud conditioning. Top and bottom plugs should pump ahead and behind the slurry to separate from the mud. Another thing that needs to ensure is the minimum and
maximum allowable flow rates to pump different fluids.

<table>
<thead>
<tr>
<th>Stand Off (%)</th>
<th>Minimum Flow Rate (bbl/min)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Laminar Flow Around the Annulus</td>
</tr>
<tr>
<td>80</td>
<td>2</td>
</tr>
<tr>
<td>60</td>
<td>11</td>
</tr>
<tr>
<td>40</td>
<td>38</td>
</tr>
<tr>
<td>20</td>
<td>&gt; 100</td>
</tr>
</tbody>
</table>

Table 3. Minimum flow rates required to achieve complete flow around the annulus. Calculated for Bingham Plastic fluid (Guillot and Nelson 2006)

Laboratory Test

Cement slurry system, preflushed and spacer should be designed and tested in the laboratory to fit the objectives which would be achieved. When mixing slurry, extensive laboratory testing needs to be run to ensure that slurry show the right properties at surface and downhole conditions (Wray, Bedford, Leotaud and Hunter 2009). Mixing technique also need to be done since some of the additives are sensitive to shear. Laboratory tests simulated at appropriate period of ambient pressure and temperature to provide proper mixing energy. Base on North (2000) the slurry was tested ± 50°F from targeted BHCT (Bottom Hole Circulation Temperature). Slurry and spacer test guidelines is describe in Table 4.

<table>
<thead>
<tr>
<th>LABORATORY TEST</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Slurry Test</strong></td>
</tr>
<tr>
<td>Temperature</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Pressure</td>
</tr>
<tr>
<td>Compressive</td>
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<tr>
<td>Strength</td>
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<td></td>
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<tr>
<td></td>
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<tr>
<td>Mixing</td>
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<td></td>
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<tr>
<td>Slurry Stability</td>
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<tr>
<td></td>
</tr>
<tr>
<td>Fluid Loss</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td><strong>Spacer Test</strong></td>
</tr>
<tr>
<td>Compatibility</td>
</tr>
<tr>
<td>Water wet ability</td>
</tr>
</tbody>
</table>
Stability
- High temperatures
- Variable rheology (to allow efficient mud removal without raising ECD)

Table 4. Slurry and spacer test guidelines (North, Brangetto and Gray 2000)

Faster thickening time or cannot achieve the desired compressive strength can be caused by cement contamination, to avoid those problems, compatibility test of drilling fluid and cement slurries should be done before the cement job. The required elasticity, tensile, compressive strength, compressibility depend on downhole condition and need to determine carefully by engineering analysis (Ravi, Bosma and Hunter 2003).

Cementing Computer Program

Cementing operation could be optimized by simulate it first in cementing computer program. It will give an overview for the proper flow pump sequence, pumping schedule (include stage timing, flow rate, volume for each fluid, worse depth scenario regarding collapse and burst), centralizer placement. Some of the program could give ECD prediction and the efficient displacement rate. The program can give the illustration of pore and fracture pressure window, so than we can decide the best slurry density, include drilling fluid conditioning, spacer, lead or tail slurry.

After proper cement placement, we need to make sure cement sheath. There is software to analyze cement sheath stress which quantifies the risk of wellbore cement sheath failure by applying stress analysis and sensitization criteria. It can model up to 10 strings simultaneously, analyzing the stress imposed on each string by a well event, such as pressure testing. The software analyzed radial and tangential stresses can determine cement sheath performance in compression, tension or both, enabling the design of the set cement behind the casing. Some of the example of non-optimized cement system and an optimized cement system done by Cement Sheath Analysis Software can be seen on Figure 13 (http://www.slb.com/~media/Files/cementing/product_sheets/cemstress.pdf).
Execution

QA & QC Materials

OA / QC of cement bulk handling that are used and good record such as documenting the batch number for each additive are essential. Sensitivity of chemical behavior should be tested in laboratory using the actual mixing water and temperature. Additional chemicals that are tested in the lab must be same as the mixing materials on the field, good sample from the rig is one of the ways. Make sure to check the levels of chloride in the mix water.

Real Time Data Accuracy

Bottom Hole Circulating Temperature (BHCT) is the temperature of cement slurry when it’s being pumped into the well and Bottom Hole Static Temperature (BHST) is the temperature of cement slurry when the pump is being stopped for period of time. In high temperature wells, slurry becomes sensitive to thickening time, causing the cement to set faster. BHCT is the bottomhole temperature that needs to consider since it will give influence to the thickening time. As the temperature rise, Plastic Viscosity and Yield Viscosity will
Precise temperature (BHCT and BHST) readings are essential for cementing HPHT wells, as an error as small as 10°F can significantly affect cement rheology and reduce thickening time. Using a cementing simulator program could give an estimation on HPHT bottom-hole temperature. Utilize Pressure While Drilling (PWD) to give real-time data to record accurate BHCT and BHST. Another parameter such as ECD, flow rate, and fluid density can be monitored by real-time data acquisition software in the rig site (Wray, Bedford, Leotaud, and Hunter 2009).

**Evaluation**

CBL and VDL

Nayfeh et al. (1984) published pressure and temperature corrections for the transducers used in CBL tools.

Foamed cement should have poor acoustic properties, a Cement Bond Log will only indicate marginal zonal isolation when 100% mud displacement is achieved (Harlan, Foreman, Reed, and Griffith 2001). On the other hand, Norwegian, North Sea wells field experience showed that certain foamed-cement slurries can be effectively logged using conventional CBL, it showed bonding quality varying between good and excellent through cemented interval (Griffith, Lende, Ravi 2004). The Ultrasonic logging tools have been developed to evaluate the impedance variation produce by the foamed cement than measuring magnitude of cement impedance.

**Ultrasonic Imager Logs**

Ultrasonic Imager Logs use a single rotating transducer to achieve full coverage of the pipe wall. Measurements are made at 36 points around the circumference. The basic idea is to make a small area of the casing...
resonate through its thickness. The transducer sends short pulse of ultrasound and listens for the echo containing the resonance. If behind the casing is fluid, it will resonate, but if it’s a solid resonance will be damped. Sonic and ultrasonic tools are sensitive to the bond between the material and the pipe. Ultrasonic logs are generally easier to interpret than sonic logs, but combination between the two logs provides more information. Supporting well information, cement job sequence (pre and post job well detail), circulation pressure and temperature data, procedure for preparing spacer or slurry is needed.

Size of cement channel is shown by cement channel angle $\beta$ (Figure 15) could be a range between $0^\circ$ to $360^\circ$ and in this paper we used 2-in height of cement channel. Figure 16 present casing eccentricity ($e$) will be calculated with equation (Yuan, Schubert and Teodoriu 2012):

$$e = \frac{2 (\text{Wellbore ID} - \text{Casing OD})}{\text{Equation 1. Casing eccentricity}}$$

For high angles wells, effects of cement channel give the maximum casing von Misses stress happens between $80^\circ$ to $120^\circ$ cement channel angle and at the wellbore angle of $90^\circ$. Cement maximum shear stress, tensile stress and radial stress happens between $40^\circ$ to $50^\circ$ cement channel angle, above $50^\circ$ channel angle, max shear, tensile and radial stress tend constant. Maximum

HPHT Crucial Problems

High Angle Well

Due to high cost associated with HPHT wells, it is a high priority to eliminate any cementing failure and to prolong the wellbore life. There is a significant difference for the von Misses stress distribution in the casing between cement having high thermal properties with thermal conductivity of $2.4 \text{ Wm}^{-1}\text{K}^{-1}$ and the cement having low thermal properties with a thermal conductivity of $0.66 \text{ /Wm}^{-1}\text{K}^{-1}$ (Manoochehr at al. 2012).

Figure 15. Cement Channel

Figure 16. Casing Eccentricity

shear stress happens between $40^\circ$ to $50^\circ$ wellbore angle. Cement maximum von Mises stress reach $2.7E4$ psi happens at the wellbore angle $40^\circ$, it’s 440% larger than stress developed at the concentric condition without cement channel (Yuan, Schubert and Teodoriu 2012). The effect of cement channel angle & wellbore angle on casing von Misses stress, cement shear stress, cement tensile stress and cement radial stress is shown in Figure 17, 18, 19 and 20.
Figure 17. Effects of cement channel angle & wellbore angle on casing von Mises stress

Figure 18. Effects of cement channel angle & wellbore angle on cement shear stress
Casing eccentricity has slightly effect on the casing von Mises stress at casing eccentricity lower than 40% at different angle wells. Von Mises stress reach maximum when casing eccentricity approach 90% between 30° and 50° wellbore angle. Cement has the highest tensile failure in cement channeling condition and highest compressive failure in casing eccentricity condition (Yuan, Schubert and Teodoriu 2012). The effect of cement eccentricity & wellbore angle on casing von Misses stress, cement shear stress, cement tensile stress and cement radial stress is shown in Figure 21, 22, 23 and 24.
Figure 21. Effects of cement eccentricity & wellbore angle on casing von Mises stress

Figure 22. Effects of cement eccentricity & wellbore angle on cement shear stress
Gas migration

Worldwide, gas migration is a common problem in the oil industry, especially in deep gas well. In Gulf Mexico more than 80% of their wells encounter a gas transmitted to surface trough cemented casing (Yetunde and Ogbonna, 2011). Very important to control the flow after cementing for deeper high pressure oil and gas wells, gas could invade and migrate through the cement matrix during waiting on cement time (Pour and Moghadasi 2007). Flowing hydrocarbons from tight formation or casing contraction during switchover from displacement fluid to sea completion fluid could create micro annuli. In Shearwater field, Central North Sea, Central Graben during switchover operation, internal casing pressure was reduced by 7,800 psi. Gas migration can lead to poor zonal isolation, high water and gas cuts, low production rates, high surface annular pressure, or even blowout.

Gas migration could invade in different stage:
- Stage one when it’s dense fluid, based on Pour and Moghadasi (2007) if the slurry higher than formation pressure gas can’t invade. But, almost immediately annulus pressure begins to fall because of gelation, fluid loss and bulk shrinkage. Premature gelation leads to loss hydrostatic pressure control. Mud filter cake between formation and cement could make pressure differential (even less than 1 psi, it may allow gas to enter the
Incorrect cement density can result in hydrostatic imbalance. If it’s assumed that wall shear stress equals the static gel strength, following equation can be used to describe hydrostatic pressure reduction during gelation:

$$\Delta P = SGS \frac{4 \, L}{D_h - D_c}$$

**Equation 2. Hydrostatic pressure reduction**

Where:
- $\Delta P$ = hydrostatic pressure changes on column
- $SGS$ = static gel strength
- $L$ = cement column length
- $D_h$ = hole diameter
- $D_c$ = casing outside diameter

- Stage two when it’s a two phase material, when the cement solid particles interconnected with the liquid phase, continued hardening and drying continues to accelerate. Hydration takes shrinkage of internal cement matrix up to 6% of cement volume, high cement shrinkage can lead to initiation of fractures and interfere in cement and casing bond. High loads encounter in deep wells compression sets in and destroys the cement sheath by compaction of matrix porosity (Elzeghaty et al. 2007). This destruction caused by mechanical failure, which creates cracks in the cement matrix, this cracks is a pathway for gas migration from formation to surface at the same time thereby shortening the life of the well.

- Stage three when cement is set, cement became an elastic and brittle material, gas no longer migrate, it can flow only through microannulus more likely results of thermal stresses (cement hydration, steam), hydraulic pressure stresses (casing pressure test, squeeze pressure) and mechanical stresses (pipe or tubular banging in the casing), mechanical failure (shrinkage induced stresses, thermal expansion).

Since cementing an unbalance wellbore in high pressure formation can cause cement migration in the cement column, killing the well using mud and perform cementing could be one of the best procedures. Most of gas channeling in a cement column occurs during a transition period from liquid to solid, latex additives help to delay cement pore pressure drop and shortened transition time between liquid and solid stage (Al-Yami, Nasr-El-Din and Al-Humaidi 2009).

Base on Al-Yami, Nasr-El-Din and Al-Humaidi (2009) experiment; **Hematite**, expansion additive and silica sand in high density cement, high temperature, and high pressure caused significant settling in mixing tanks. **Manganese tetraoxide** by itself does not control gas migration, but adding hematite to manganese tetraoxide improved the gas migration resistance. As the depth increase, sometimes reducing the mud density will reduce the pressure can cause the casing to shrink, led to micro annulus or the cement casing bond could break, which will allow gas to flow. Expanding additives recommended for cement jobs for a gas producing formation and the depth greater than 10,000 ft. (Jennings et al. 2003). Test using the combination of 45% BWOC Manganese Tetraoxide, 45% BWOC Hematite, 10%...
BWOC silica sand and 25% BWOC silica flour showed an outstanding result of zero gas permeability with no gas breakthrough and zero fluid loss. Class G Cement + 35% BWOC Silica sand + 185% BWOC Hematite + 5% BWOC expansion additive at cement densities up to 22.7 lbm/gal are used to cement high pressure formation in terms of minimizes gas migration, fluid loss and settling (Al-Yami, El-Din and Al-Humaidi 2009; Al-Yami, Schubert, Cetina, and Yu 2010).

Pour and Moghadasi (2007) stated in gas migration phenomenon, high gel strength development may help resist gas percolation therefor suggested to use thixotropic and high-gel-strength cements. Thixotropic systems are unlikely to be effective in situations where the gas zone pressure exceeds the water gradient, unless additional backpressure is held in the annulus.

Lost Circulation / Weak Formation

Prevention

Low density slurry or foam cement is chosen for certain advantages in deepwater application, which sometimes encounter in tight mud window HPHT well. Lightweight cement is a special formulation composed of Portland cement clinker and lightweight siliceous aggregates, where consequently some pozzolanic activity occurs. The particle size distribution is finer than Portland cement, could give slurry density range between 11.9 lbm/gal to 13.7 lbm/gal. Nowadays there is 7.5 lbm/gal slurry system that can provide the high strength and low permeability which can provide equal compressive strength and permeability to 15.8 lbm/gal cement.

To get lighter cement density besides water, gas can also be used as a slurry base. Foams have lower thermal conductivity since the presence of gas voids and lower amount of solid (Short et al. 1961). Thermal conductivity of a cement system is roughly proportional to slurry density, regardless of whether the cement was foam (Nelson 1986). Nitrogen incorporates directly into the cement slurry to obtain low-density foamed cement. Formulated base cement slurries needed to prepare a homogeneous system with high compressive strength and low permeability. Foamer concentrations were constant and nitrogen rates were driven to control downhole density during lead and tail cementing work (Harlan, Foreman, Reed and Griffith 2001).

Foam cement is more ductile than non-nitrified cements and resistant to both temperature and pressure-cycling-induced sheath stresses (Marriott, Griffith, Fyten, Mallett and Szutiak 2005), which will lead to allow cement sheath to yield while the casing expands and then rebound when the casing returns to its original conditions (Griffith et al 2004). The test shows that above 35-quality foamed cement is generally too porous to provide isolation and below 20-quality foamed cement is generally too brittle to provide the minimum ductility (Harlan, Foreman, Reed and Griffith 2001). Foam sealant slurry could be a compressible fluid and less sensitive to loss of hydrostatic pressure due to slurry gel strength development (Biezen and Ravi 1999). Wells that we drill have irregular shape, foam slurry could expand and fill the gap in the annulus. This feature has stable rheological properties, which lead to efficient displacement, the density could be from 7 to 15 lbm/gal. After setting, it could be a long term sealing and can bond well casing and formation. Foam slurry is a are considered to have superior mud removal properties and the capability of filling lost
circulation voids (Pine et al. 2003), eliminate free water development, expansion properties, controlling gas migration or formation influx, increase ductility, and higher tensile strength. Comparison between lightweight slurries and foamed cement can be seen in Figure 11.

**Figure 11. Compressive strength and permeability lightweight slurries vs. foamed cement**

### Treatment

Lost circulation problems can occur while drilling or cementing in HPHT wells, it can be expensive and time consuming. Lost circulation occurs by natural or induced mechanism, it was divided into categories; unconsolidated formations, high permeable or low pressure formations (depleted zones), natural fractures, induce vertical or horizontal fractures and cavernous & vugular formations (limestone or dolomite formations). Severity classification for lost circulation is shown in Table 5. Losses location should be determined accurately, lost circulation material and techniques must be match to the type and severity of the loss zone. Data records from previous lost circulation history often points the way to an effective solution.

<table>
<thead>
<tr>
<th>Type of Losses</th>
<th>Severity (bbl/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seepage – minor</td>
<td>&lt; 10</td>
</tr>
<tr>
<td>Partial – medium</td>
<td>10 to 100</td>
</tr>
<tr>
<td>Severe – massive</td>
<td>100 to 500</td>
</tr>
<tr>
<td>Total - complete</td>
<td>Unable to keep the hole full</td>
</tr>
</tbody>
</table>

**Table 5. Severity classification for lost circulation (Nelson 2006)**

If lost circulations during cementing are anticipated there are two methods. *First*, decrease downhole pressure by reducing slurry density below ECD, minimizing the height of cement column, limiting casing and annular friction pressure during the placement of cement slurry. *Second*, pump plugging material as a spacer in front of slurry that has been given lost circulation material or other additives that have thixotropic properties to the slurry (Nayberg and Linafelter 1984).

The most common LCM is the granular type, since *Gilsonite* has a low melting point 220°F make it not suitable for high temperature wells. *Crush coal* in mesh range 14-22, which has a melting point approximately 1,000°F can be used in high temperature wells as well as shells from *walnuts*, pecan and nuts. *Cellophane flakes* at concentration above 2lbm/sk, mixing with cement slurry become extremely difficult. As well as *nylon* and *polypropylene*, they have tendency to plug pump plungers and float equipment. Most recently *silica base fibers* have been developed (Messier et al. 2002,
Thixotropic cement has been used to overcome severe lost circulation problems. Thixotropic cement is cementing slurries where it remains liquid when sheared (pump) and begin to turn into a gel when the shear stops. Another way to solve lost circulation problems is lowering the density by using foam cement system (Nayberg and Petty 1986).

**HPHT Sidetrack**

In HPHT deep wells, from one wellbore they could have multilateral wells to reach different reservoir zones. Sidetrack operation have been used to overcome the HPHT challenges. Al-Yami, et al. (2006) mention maximum formation compressive strength is can reach up to 22,500 psi and maximum cement compressive strength is 5,000 to 9,000 psi. To provide good isolation, 100 psi cement compressive strength is required. The compressive strength of regular cement is much lower than that of formation leads to highly fast cement rate of penetration. By increasing cement compressive strength it will minimize the difference in rate of penetration between cement plug and formation.

For sidetrack drilling using weighting material such as hematite or manganese oxide with conventional cement is more effective compared to special high density blend. By increasing cement density is more effective, silica solid is recommended to be used to reduce the rate of penetration. Expansion additives and manganese oxide with silica material showed no improvement in rate of penetration. 24 hours waiting on cement is recommended in most cases before drilling it. Slow rate of penetration formulation is combination mixed cement and cured at 290°F resulted from a strong cement core, it’s ensure thickening time and settling test are acceptable, which make slow rate of penetration (SRP) formulation is the best solution to achieve good sidetrack drilling (Al-Yami, Jennings, Nasr-El-Din, Khafaji and Al-Humaidi 2006; A-Yami et al 2008).

**Casing Collapse**

In HPHT wells casing collapse probability is there, cement sheath not only provides zonal isolation but also supports casing and increase casing collapse resistance. In HPHT gas wells the differential pressure inside between formation and casing is larger than normal wells, it will give greater challenges to casing integrity. Reducing cement Young’s modulus will reduce cement maximum von Mises stress and increase cement maximum shear stress. Modified cement Young’s modulus could prevent cement shear failure. Maximum von Mises stress difference is only 0.27% for 0.3 inch casing eccentricity, it doesn’t have much effect on casing and cement. Stress in the casing under elastic cement is 12% lower than stress in the casing under brittle cement (Yuan and Schubert 2012).

**Environmental Restriction**

UK sector of North Sea has government regulations that materials are characterized by the volumes that may be discharged into the sea. For cementing material it categories from A to E. Category A materials discharge is strictly limited while category E much freer. Most of the materials go to category E, and it showed high performance could be achieved while comply with environmental regulation (North and Gray 2000).

Some of the areas or different countries have restricted environmental regulation. Regulation to have biodegradability chemical materials sometimes is contradictory with HPHT chemical properties demand. Development of new chemicals that meet environment regulation and effective at high temperature / high pressure should be sought.

**Technology Solution**

Nowadays, cementing technology allows cementing last in higher pressure or higher temperature. Technology to reduce WOC (Waiting On Cement),
would be very meaningful for wells that require substantial operational cost such as deepwater wells or deep HPHT multilateral wells. Technology solutions have been made and continue to be developed to provide long life cementing zonal isolation.

*High Angle Well* – In high angle well if it’s giving over stress in casing or cement, one of the ways to overcome this is by providing proper casing centralizer or reduce cement channel. If those ways can’t help, changing the well or cementing design should be implemented.

*Gas Migration* – Most of the gas channeling in cement column occurs during a transition period from liquid to solid, adding latex additives help to delay cement pore pressure drop and shortened transition time between liquid and solid stage (Al-Yami, Nasr-El-Din and Al-Humaidi 2009). To prevent gas migration, slurry modification could be done by decrease volume losses, extend zero gel time, reduce transition time adding gas influx preventing material and increase slurry compressibility. Job design changes could be done by decrease effective column height, increasing overbalance pressure, interfering with the gelation process and drilling a larger diameter hole (Wray, Bedford, Leotaud and Hunter 2009).

*Across weak formation* – Lightweight slurry system that has high compressive strength and low permeability should be used to cement a weak formation. The lightweight system could give 7.5 lbm/gal slurry densities and even comparable to 15.8 lbm/gal cement properties. Foamed cement (by adding gas and surfactant) also can be considered in very weak formation, it can mix immediately prior to the job, unlike pre-blended cement. And if there has been a lost circulation, decrease downhole pressure and pump plugging material LCM (lost circulation material).

*High-Pressure well / kickoff plug* – High density cements up to 24 lbm/gal could be used for kickoff plug or to handle well control issue specially to provide high pressure zonal isolation.

*Isolation problems (Microannulus)* – Expanding agent can be selected to prevent microannulus in cement set and squeeze cement material could be used to handle microannulus cement by fill the empty space without dehydrating or bridging during placement.

*Changes in pressure and temperature throughout well’s life* – Flexible cement additives fabricated to provide flexibility to overcome stress changes in the wellbore, higher compressive strength and lower permeability.

*Interrupt cement sheath* – Durable cement additives to provide a high quality cement sheath even disturbed by vibration or impact mechanical shock stress.

**Summary & Conclusion**

1. Based on the survey in HPHT Summit, cement design is one of HPHT technology gaps that should be given high attention. In the design phase increase of temperature will decrease plastic viscosity and yield viscosity (Ravi and Sutton 1990). And to overcome strength retrogression problem, when the static temperature exceeds 230°F, 35 % - 40 % silica by weight of cement should be added to Portland cement. For temperatures exceeding 750°F, High Alumina cement is more suitable rather than Portland cement. Silica in High Alumina cement should not be used as an extender for temperature exceeding 572°F. Fly ash or aluminosilicate firebrick is more suitable. If the static temperature exceeds 450°F fly ash should not be used in Portland or Class J cement, bentonite, perlite is suitable.

2. Glass microspheres with hydrostatic crush strengths could hold 10,000 psi but ceramic microspheres only can withstand up to 3,000 psi, both could be used in thermal wells since they stabilize in high temperatures (Nelson 2006).
Assumption that high compressive strength is linked to low permeability is false. In general, set cements that consist of cement silica ratio less than or equal to 1.0 tend to have higher compressive strengths and lower water permeability. Cement set not only depends on downhole temperature, but also presence of other minerals, its composition can evolve as downhole conditions change. Proper amount of Retarders must be blended into the cement system, if it’s too much it will cause long waiting on cement and in high pressure wells may lead the entry of gas into the cement.

3. Combination of silica sand, silica flour, hematite, manganese tetraoxide with expansion additives showed the best performance in terms of minimizing gas migration, fluid loss and settling. Hematite, expansion additives and silica sand in high density cement HPHT caused significant settling in mixing tanks. Manganese tetraoxide by itself does not control gas migration, but adding hematite to manganese tetraoxide improved the gas migration resistance (Al-Yami, Nasr-El-Din and Al-Humaidi 2009).

4. For high conditioning temperature 300°F to 400°F using 2200°F burnt MgO more preferable. The effective expanding additive concentration for increasing shear bond strength is ranging from 5 to 10 % (Rubiandini 2000). General guidelines such as fluid loss should be in range of 50 ml per 30 minutes. Generally, 70% standoff is considered as minimum requirement to have good cement bond, casing needs to be kept in the center of the wellbore. Improving pipe stand-off, increasing $\mu_p / T_y$, decreasing mud gel strength and increasing flow rate are important factors to achieve a good mud removal. Cement slurry system, preflushed and spacer should be designed and tested in the laboratory to fit the objectives which would be achieved. Cementing operation could be optimized by cementing simulator program, real time data accuracy, quality analysis and quality control of materials.

5. For deep and hot wells, one must consider an accurate static and circulating temperature to obtain efficient thickening time and optimal compressive strength. For high pressure wells, we must consider an anticipated bottomhole pressure to obtain good well control or avoid fluid invasion. To control gas migration, the “zero gel” time can be long but the transition time should be as short as possible, preferably less than 30 minutes (Diamond 1983). Cement evaluation could be done with CBL, VDL, Ultrasonic Imager Logs or combination of them.

6. For high angle wells, effects of cement channel give the maximum casing von Misses stress happens between 80° to 120° cement channel angle and at the wellbore angle of 90°. Cement maximum shear stress, tensile stress and radial stress happen between 40° to 50° cement channel angle. Above 50° channel angle, max shear, tensile and radial stress tends constant. Maximum shear stress happens between 40° to 50° wellbore angle. Casing eccentricity has minor effect on the casing von Mises stress at casing eccentricity lower than 40% at different angle wells. Von Mises stress reach maximum when casing eccentricity approach 90% between 30° and 50° wellbore angle. The maximum von Mises stress difference is only 0.27% for 0.3 in eccentricity and the casing centered in the hole (Yuan, Schubert and Teodoriu 2012).

7. When cement additives are not dry blended with the bulk cement, liquid additives are preferable to allow accurate addition and reduced mixing time. To provide greater control and consistency, in HPHT operation or long liner section, cementing involves large fluid volumes, which also require a large batch tank for crucial jobs (North, Brangetto and Gray 2000).

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The statements made herein are solely the responsibility of the authors.

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