

Innovative Lost Circulation Control Methods: Managed Temperature Drilling, Thermal Wellbore Strengthening and OBM / SBM-to-Cement Conversion

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Abstract

This paper showcases novel R&D results on lost circulation prevention and recovery in two main areas: (1) deliberately manipulating the temperature in a wellbore and near-wellbore rock formations to strengthen the wellbore thermally; (2) novel technology to solidify oil-based/synthetic-based mud and use the hardened product as a lost circulation material. Both technologies use novel chemistries and provide for much-needed innovation in lost circulation control.

Managed Temperature Drilling involves the precise control of temperature in a well. The technology reported here uses chemicals that can be circulated to a potential loss zone and activated to generate an exothermic (“heat-releasing”) reaction that heats the near-wellbore zone and increases its tangential stress, thereby increasing fracture initiation and propagation pressures. This constitutes Thermal Wellbore Strengthening. The chemicals are simple salts such as CaCl_2 and MgCl_2 that can be coated to delay the exothermic reaction and allow sufficient circulation time before the reaction takes place.

Alkali-activated materials can be mixed with non-aqueous fluids at high concentrations to generate a pumpable cementitious material that sets up with moderate strength (several 100 psi). This makes it well-suited for cementing up natural or induced fractures, eliminating the contamination issues often encountered while squeezing Portland cement.

Details on the technologies, lab test results, and considerations for field implementation are provided.

Introduction

It is undeniable that Managed Pressure Drilling (MPD) technologies such as the Constant Bottom Hole Pressure (CBHP) method and Pressurized Mud Cap Drilling (PMCD) method have greatly improved our ability to negotiate narrow drilling margins and mitigate losses. Whether it is drilling in complex low-margin deepwater wells or penetrating fractured carbonate reservoirs, MPD technologies provide comprehensive solutions to lost circulation challenges. This truly excellent “mechanical” progress is unfortunately not matched by similar innovations in chemistry. Chemical technologies for lost circulation prevention and mitigation are now decades old. Industry workshops on lost circulation often devolve into a debate (with heated arguments among the antagonists involved) on whether particle X offers more benefits than particle Y, and which of them is better suited to

bridge a particular pore size or fracture of a particular width. This criticism also pertains to the more recent topic of artificial wellbore strengthening (WBS), which in its essence is nothing more than an articulation of conventional lost circulation material (LCM) application repackaged into specific rules around either carrying out dedicated squeezes or keeping sufficient amounts of specifically sized WBS materials in the mud to raise the effective fracture propagation pressure.

This paper introduces two novel chemical lost circulation control methods, Thermal Wellbore Strengthening (TWBS) through Managed Temperature Drilling (MTD) and oil-based/synthetic-based (OBM / SBM) solidification through alkali-activated materials (AAM). These methods have little in common, other than that they provide entirely new chemical ways of dealing with lost circulation. These innovative technologies are presented here to hopefully spur talented young researchers to forego well-trodden paths in mud loss mitigation (i.e. not just another particulate material, adding to the dozens already available, most derived from some non-oilfield waste stream and supposedly superior at stopping losses), and explore entirely new avenues in dealing with the oil and gas industry’s continuing problems with non-productive time and trouble costs associated with downhole mud losses.

Thermal Wellbore Strengthening (TWBS) by Managed Temperature Drilling (MTD)

Introduction

Temperature influences near-wellbore rock stresses, and thereby the fracture gradient, of a borehole. Stress variations caused by temperature changes are often ignored, either because they are poorly understood or because the variations in near-wellbore temperature are small. However, changes in the near-wellbore temperature can have a substantial effect on the stress distribution around the wellbore. This has been recognized by several authors, who have noted the effects of wellbore cooling through mud circulation inadvertently leading to lost circulation in deepwater wells (see e.g. Gonzalez et al., 2004; Hettema et al., 2004; Algu et al., 2007). Mud losses are often observed on these wells after tripping into the hole when circulation recommences. Induced fracturing occurs without any noticeable increase in equivalent circulating density (ECD), simply because of the cooling effect of the mud circulation, which lowers near-wellbore tangential stresses.

The near-wellbore effect of a temperature difference ΔT between a rock formation and the wellbore fluid on tangential stress σ_{θ} is given under steady-state conditions (see e.g. Zoback et al., 2003) by:

$$\sigma_{\theta}^{\Delta T} = \frac{\alpha E \Delta T}{(1 - \nu)} \quad (1)$$

where α , E and ν are the thermal expansion coefficient [1/K], Young's modulus [Pa] and Poisson's ratio [dimensionless] of the rock formation respectively. The temperature difference ΔT [K] is negative for cooling of the wellbore wall (wellbore temperature lower than in-situ formation temperature), whereas it is positive for heating of the wellbore wall (wellbore temperature higher than in-situ formation temperature). In the latter case, the near-wellbore tangential stress, and thereby fracture initiation and propagation pressure, can be raised by heating of the rock formation. This is the essence of thermal wellbore strengthening (TWBS): raising the near-wellbore tangential stress through active heating by actively manipulating the fluid temperature in the wellbore. This process of active and beneficial wellbore temperature manipulation can be referred to as managed temperature drilling (MTD) in analogy to MPD, which involves active and beneficial manipulation of annular and bottom-hole pressures.

Wellbore Heating

Entertaining the concept of MTD-TWBS immediately raises the question on how this might be achieved. There are several options in theory:

1. Heating the fluid of interest from surface and circulating it downhole. This may seem like an obvious solution in theory, but it is unfortunately unlikely to succeed in practice. First, heating the mud pits on surface would place very high demands on rig power, particularly offshore, which is not desirable. Furthermore, the well itself, and particularly the riser section of offshore wells, would act as an effective heat exchanger that would siphon away much of the surface-imparted heat before the mud ever reaches its target. In (ultra-)deepwater drilling in particular, the long column of cold seawater surrounding the riser exerts a strong cooling effect and makes this form of heating ineffective.
2. Using a downhole circulating sub that would convert hydraulic energy into heat, similar to what has been proposed for electrical submersible pumping systems (see e.g. Neuroth et al., 2011). This option, however, would place high requirements on mud pump pressures and would require high flow rates, which would directly translate in high annular frictional pressure losses and associated ECDs. This is far from desirable in a narrow drilling margin environment.
3. Downhole heating through electrical means (see e.g. Sahni et al., 2000; Parman et al., 2014) or electromagnetic (microwave or ultrasonic) means (see e.g. Abernethy, 1976; Vermeulen and McGee, 2000, Gunal et al., 2000, Bjorndalen and Islam, 2004) has been proposed for heavy oil production.

It is only an option in theory for MTD-TWBS given the power requirements, cost and complexity to deploy in the field, particularly in offshore drilling environments.

4. Downhole heating through chemical means, using a controlled exothermic reaction (Grant et al., 2014; van der Haak et al., 2014). The principle is shown in Fig.1. It relies on circulating a material or combination of materials that can react in an exothermic (i.e. heat-releasing) fashion down to a zone targeted for TWBS, such as a weak zone prone to experience lost circulation. Once the material is opposite the zone, the exothermic reaction is triggered and the zone is heated in the near-wellbore region, raising the fracture gradient. This might be accomplished e.g. prior to circulating cement in place in order to prevent losses while cementing. This option appears at present to be the only viable one, and is explored further below.

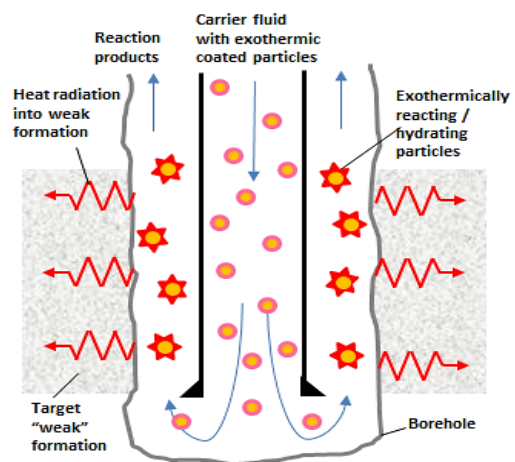


Figure 1 - Principle of TWBS by MTD: coated salt particles that can react exothermically are circulated to the target formation to be strengthened, whereupon the coating dissolves and the exothermic reaction radiates heat into the formation, raising near-wellbore temperature and fracture gradient.

Chemical System

To accomplish heating as indicated in Figure 1, two requirements need to be met: (1) a suitable exothermic reaction needs to be used that can realistically be implemented while meeting both safety and technical requirements, the latter including generating a sufficient amount of heat that can thermally "strengthen" the wellbore in a meaningful way; (2) a mechanism is needed to delay the exothermic reaction until the reactant(s) can be circulated across the zone of interest, with delay times taking tens of minutes to hours.

Table 1 shows several exothermic reactions that are suitable for the intended purpose. They involve dissolutions of the salts of calcium and magnesium with chlorine and bromine in water. The reason these reactions were chosen is because of their relatively large reaction enthalpy, and the fact that the industry has ample experience of using CaCl_2 , CaBr_2 , MgCl_2 and MgBr_2 solutions for well construction purposes, notable as completion brines. These salts, of course, have to be suspended in a water-based environment in order for dissolution to occur.

Table 1 – Enthalpy of hydration (ΔH) of salts of calcium and magnesium with chlorine and bromine, upon dissolution in water at 18°C (from Liley et al., 1997) for CaBr_2 , MgCl_2 and MgBr_2 , and at 25°C for CaCl_2 (from Dow, 2003). Negative values indicate exothermic dissolution reactions with heat release.

$\text{CaCl}_2(s) \xrightarrow{\text{H}_2\text{O}} \text{Ca}^{2+}(aq) + 2\text{Cl}^-(aq)$	$\Delta H = -81.8 \text{ kJ/mol}$
$\text{CaBr}_2(s) \xrightarrow{\text{H}_2\text{O}} \text{Ca}^{2+}(aq) + 2\text{Br}^-(aq)$	$\Delta H = -104.0 \text{ kJ/mol}$
$\text{MgCl}_2(s) \xrightarrow{\text{H}_2\text{O}} \text{Mg}^{2+}(aq) + 2\text{Cl}^-(aq)$	$\Delta H = -151.9 \text{ kJ/mol}$
$\text{MgBr}_2(s) \xrightarrow{\text{H}_2\text{O}} \text{Mg}^{2+}(aq) + 2\text{Br}^-(aq)$	$\Delta H = -182.8 \text{ kJ/mol}$

If the aforementioned salts were to simply be placed in water, they would react immediately and the entire exothermic reaction would be over in less than a few minutes. If this were to happen in actual field practice, this would mean that heating would start while mixing the materials in their water-based carrier fluid either at – or close to – surface. The effect would be similar to heating the mud on surface using heaters, which would preclude effective heat transport to downhole formation (see above discussion on the ineffectiveness of using surface heaters for TWBS purposes).

A technique from the pharmaceutical industry can be adopted to delay the exothermic reaction. Oral drugs often have an “enteric” coating that prevents their dissolution or disintegration in the acidic environment of the stomach. This coating, achieved with suitable polymers, protects the drug from disintegrating at high acidity, protects the stomach from any detrimental effects of the drug, and/or enables the release of the drug after passing the stomach. A hydrophobic coating can similarly protect the exothermic salt particles from contacting water until the coating has degraded, thereby allowing for a precisely timed release of the particles. Coating dissolution is determined by the chemistry of the constituents of the coating as well as external factors such as exposure time, degree of shear on coated particles, temperature, pressure, a certain pH environment, or a combination of these.

The idea of a dissolvable coating is shown schematically in Figure 2. Under the influence of external factors, the coating eventually cracks and dissolves, allowing water to access the salt particles, which start to dissolve exothermically. The hydrophobic coating can be formulated in such a way that the coating dissolves at exactly the right time. Coatings strategies are beyond the scope of the present paper, but a comprehensive review can be found in Rhodes and Porter (1998).

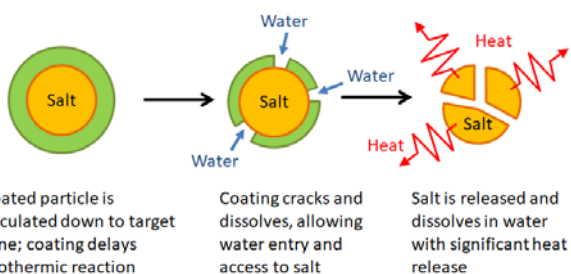


Figure 2 - Principle of extended release with coated salt substrates.

Figure 3 shows 1-3 mm CaCl_2 particles coated with a dissolvable cellulose coating that has been dyed with a Rhodamine dye. The coating, which was spray-coated onto the particles using the pan tumbler method (see Rhodes and Porter, 1998) has a thickness of several hundred microns. Whether the salt particles can be coated or not depends greatly on morphology of the substrate, which may in granular, flaky or powder form. For some substrates it is not possible to coat them directly, but coating may be possible after the materials are pressed into tablets or loaded into capsules that can be coated. Humidity needs to be carefully controlled during coating, as hydration of the hygroscopic salts will reduce the magnitude of the exothermic reaction that will ultimately result (i.e. the enthalpy of the exothermic reaction is suppressed for hydrated salts compared to the anhydrous salt).

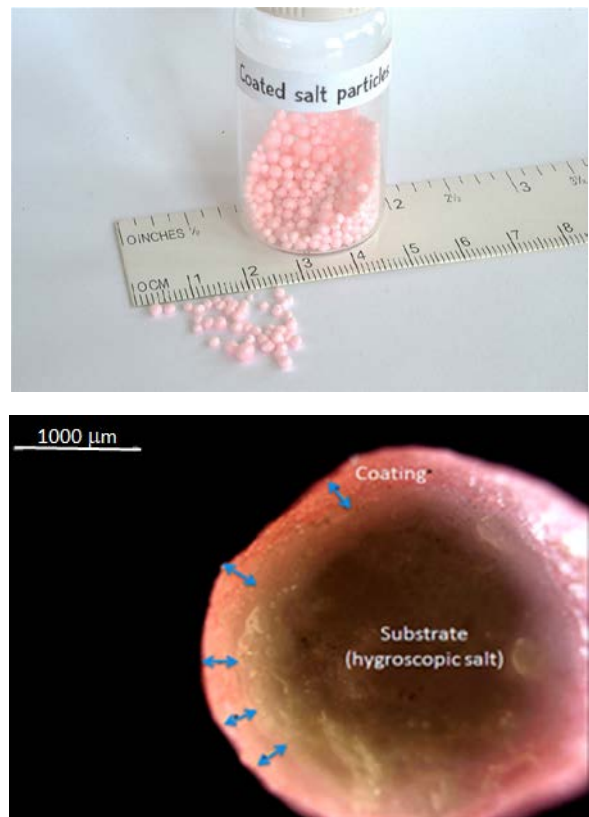


Figure 3 – 1-3 mm CaCl_2 particles coated with a hydrophobic cellulose coating colored by Rhodamine dye. The thickness of the coating is ~ 200 microns.

Calorimeter experiments were performed to characterize the exothermic behavior of various substrates in coated and uncoated form at various concentrations. Details on these controlled exothermic experiments are given elsewhere (Hoxha et al., 2016). Figure 4 shows typical examples of results obtained. Figure 4A demonstrated what happens when uncoated CaCl_2 is contacted at room temperature (21°C initial temperature) by water: a strong exothermic response is observed with a heat generation rate of ~1,600 kW/m³ leading to a temperature increase of ~57°C in less than 2.5 minutes.

Evidently, a heating response that will only last for a few minutes will be of little use to us in the field. As explained above, such a response would only heat the fluid in the mixing pits and the upper part of the drillstring/workstring, but would not effectively heat formations deeper in the well. Time-delay achieved through coating is clearly necessary. This is shown in Figure 4B. Here, the CaCl_2 particles were coated with a wax coating that dissolves when a certain external temperature is reached, i.e. coating dissolution is temperature-activated. In the experiment, the coating was triggered after 100 mins of residence time in the calorimeter. Note that the observed delayed exotherm of the coated salt mimics the exotherm of the original uncoated salt with no apparent loss in intensity of the heating response and the overall temperature increase achieved. This result demonstrates clear proof of concept that delayed thermal wellbore heating is possible.

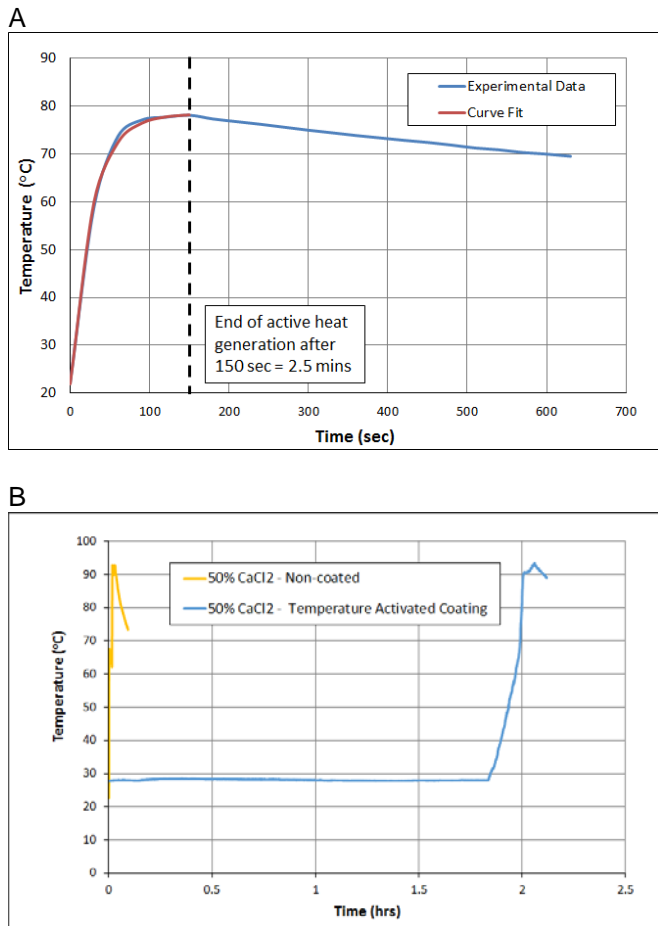


Figure 4 – A. Exothermic response of uncoated CaCl_2 particles dissolving in water at room temperature; note that the heating response is essentially over after 2.5 mins of heating time. **B.** Delayed exothermic response (blue curve) achieved by coating CaCl_2 particles with a temperature-activated wax coating; note that the magnitude of the heating response is similar to that of the uncoated salt (yellow curve).

Thermal Modeling Results

In order to quantify the temperature increase experienced by the near-wellbore because of thermal heating inside of it, one has to solve Eq.2. It presents the governing energy conservation equation, and consists of four terms: the transient accumulation term, the convection term, which represents the contribution of heat transport in the velocity field, the diffusion term, and the heat generation term. Since there are different media in the domain of the problem of interest, Eq. 2 needs to be solved for each medium separately and the interactions between these media need to be identified with appropriate boundary conditions:

$$\frac{\partial}{\partial t}(\rho cT) + \nabla \cdot (\rho \mathbf{U} cT) = \nabla \cdot (k \nabla T) + S(z, t) \quad (2)$$

In this equation, ρ is density [kg/m^3], c is specific heat capacity [kJ/kgK], T is temperature [K], \mathbf{U} is the velocity vector [m/s], k is thermal conductivity [W/mK], and S is volumetric heat generation [kW/m^3] which is a function of time t [s] and vertical distance z [m]. Note that none of the currently available thermal models can simulate the MTD-TWBS mechanism, as these do not account for volumetric heat generation and axial heat transfer.

The details on how Eq.2 was modeled is beyond the scope of this paper, and the reader is referred to Hoxha et al. (2016) for more details. Some numerical modeling results are shown here for the situation where a TWBS treatment precedes the placement of cement. Strengthening a wellbore thermally prior to cement placement may be particularly useful in order to avoid losses while cementing in narrow annuli, thereby helping to achieve appropriate zonal isolation. A schematic of the modeled configuration is shown in Figure 5.

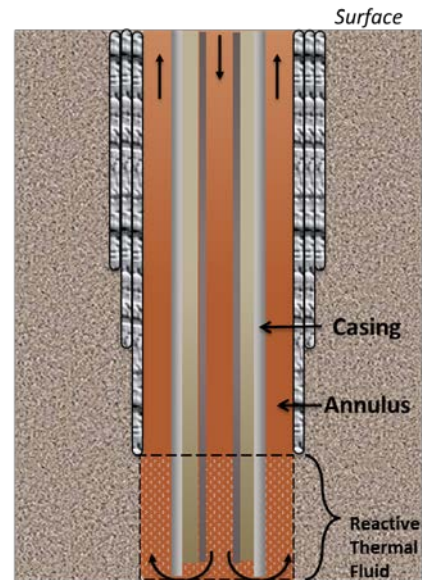


Figure 5 – Well schematic for application of a TWBS treatment prior to cement placement to avoid induced lost circulation because of high ECD's in narrow annuli.

Simulation parameters for an offshore Gulf of Mexico well scenario are given in Table 2. 11 7/8" casing has been run into 14 3/4" hole at 16,000 ft. The casing is circulated for a period of 240 mins / 4 hours before the TWBS particles arrive at the target formation. During this time, the bottomhole temperature drops as cool mud circulated from surface cools the downhole formation. A significant increase in temperature, however, is observed once heating starts, as shown in Figure 6, which displays the temperature response at the rock face and inside the formation for an active heating and circulation period of 2 hours. The various plots in Figure 6 represent different combination of heat generation and circulation rate: A. 325 kW/m³ and 36.34 m³/h / 160 gal/min; B. 100 kW/m³ and 36.34 m³/h / 160 gal/min; C. 100 kW/m³ and 11.36 m³/h / 50 gal/min;

Figure 6A shows that temperature at the rock face at the depth of the casing shoe rapidly increases by approximately 50°C / 90°F at the high heat generation rate of 325 kW/m³, and continues to increase by a total of approximately 100°C / 180°F as circulation continues. However, this temperature increase response is suppressed at the lower heat generation rate of 100 kW/m³, as shown in Figure 6B. The temperature response in this case is on the order of 20°C / 36°F. However, if the circulation rate is lowered from 36.34 m³/h / 160 gal/min to 11.36 m³/h / 50 gal/min, a stronger temperature result is seen for the same heat generation rate, as shown in Figure 6C. Initial and final temperature responses are approximately 40°C / 72°F and 60°C / 108°F respectively. This result shows that the heat generation rate and the circulation rate need to be optimized in tandem in order to get the best formation temperature response. The thermal model allows for this optimization through case simulation before carrying out a TWBS treatment in the field.

After heating ceases, the temperature relaxes back to the initial state. This, however, takes time, meaning that elevated temperature – and thereby elevated near-wellbore tangential stress – persists for a while. This allows for circulating cement in place, which is usually accomplished in only a few minutes.

Table 2 – Simulation parameters for an offshore Gulf of Mexico well scenario			
Simulation Parameters		SI Units	Field Units
Casing OD		0.3016 m	11 7/8 in
Casing ID		0.2721 m	10.711 in
Annulus Clearance		0.0365 m	1.4375 in
Far field distance		0.5 m	1.64 ft
Well Depth		4877 m	16000 ft
Circulation Rate		14 l/s	160 gal/min
Injection and Surface Temperature		4.44 °C	40 °F
Formation Temperature Gradient		0.01434 °C/m	0.00787 °F/ft
Material Thermal Properties			
	Density (kg/m ³)	Specific Heat Capacity (J/kgK)	Thermal Conductivity (W/mK)
Fluid	1384	2500	1.02
Casing	7840	800	50
Formation	2500	1200	2.2

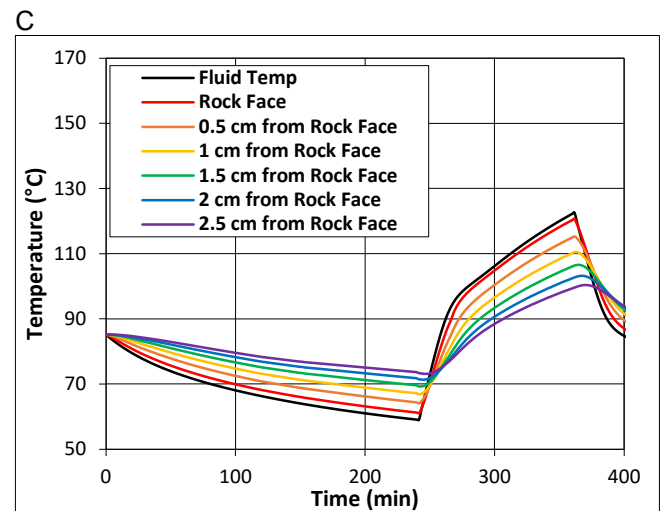
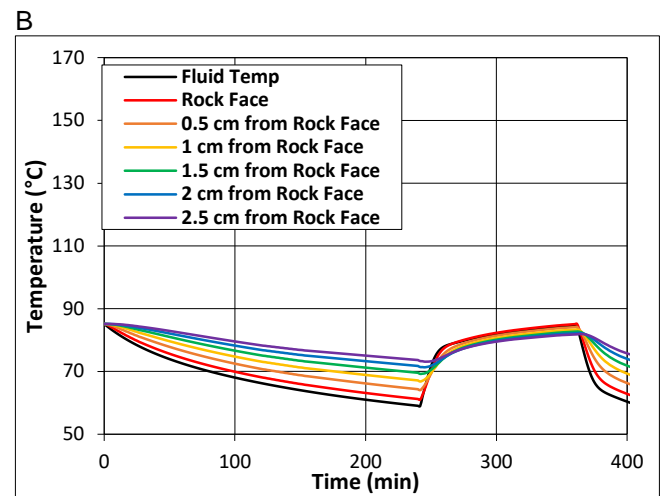
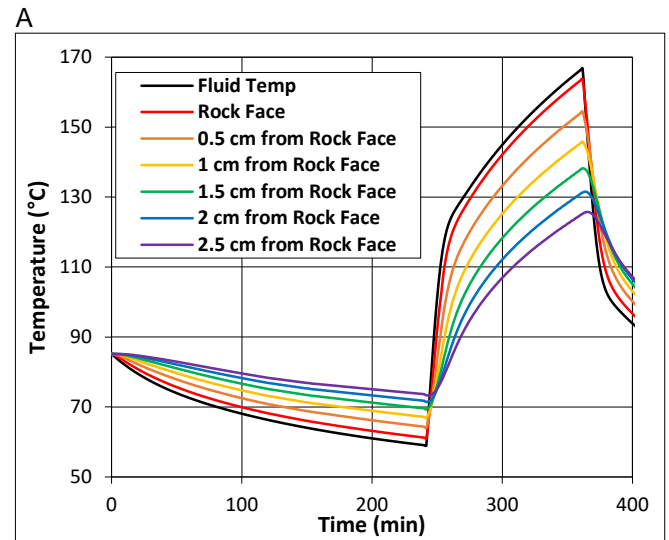


Figure 6 – Temperature profiles for scenarios where there is 2 hours of active heating after 4 hours of regular mud circulation before cementing an 11 7/8" casing string in a deepwater well. Heat generation and circulation rates for the three cases are: A. 325 kW/m³ and 36.34 m³/h / 160 gal/min; B. 100 kW/m³ and 36.34 m³/h / 160 gal/min; C. 100 kW/m³ and 11.36 m³/h / 50 gal/min.

Finally, an estimation was made on the increase in tangential stress caused by heating, which translates directly to an increase in fracture initiation pressure and near-wellbore propagation pressure in accordance with Eq.1. Figure 7 shows the expected increase for several rock types, including shale, limestone and sandstone, as a function of distance away from the wellbore for the case of 325 kW/m^3 heat generation rate and $36.34 \text{ m}^3/\text{h}$ / 160 gal/min circulation after 2 hours of exposure (simulation case of Figure 6A) and rock mechanical parameters previously published (Razavi et al., 2015 & 2016). The thermal stress increases are directly proportional to Young's modulus and thermal expansion coefficient (cf. Eq.1).

A general observation is that heating can increase the near-wellbore thermal stress by several MPa / several hundred psi, which is expected to lead to a meaningful increase in the effective fracture gradient. For instance, a 500 psi thermal stress increase at 16,000 ft TVD (cf. simulation case of Figure 6), which is the lowest value achieved for the cases in Fig.7, yields an increase of 0.6 ppg of the effective fracture gradient. This may be sufficient to minimize or even eliminate induced lost circulation while circulating cement in place.

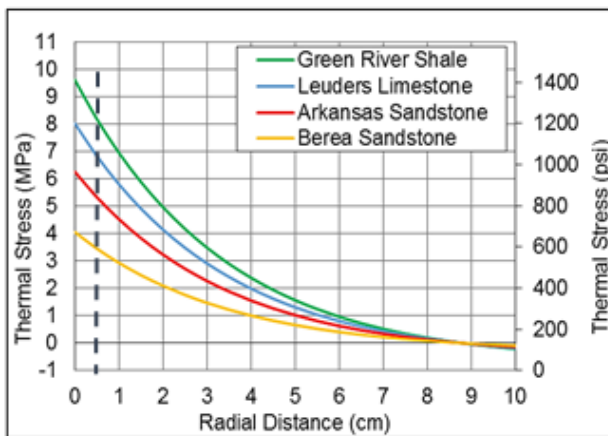


Figure 7 – Thermal stress increase as a function of distance away from the wellbore for various rock types.

Considerations for Field Application

Before field application can be considered, several important practical issues need to be addressed, some of which are discussed here. Quality assurance and control (QAQC) in selecting and handling of the hygroscopic salt material is crucial, in particular prior to – and during – the coating process. Likewise, there will need to be good quality control in layering the right chemical coating onto the material, which governs the delay of the exothermic reaction.

While near-wellbore temperature increase has a positive effect on lost circulation tendency, it could potential trigger or exacerbate wellbore instability problems. The increase in hoop stress around the wellbore from increased thermal stresses may lead to enhanced shear failure of the wellbore wall, with associated non-productive time. The impact of heating on wellbore stability therefore needs to be well-understood and any negative consequences need to be mitigated.

As already mentioned, a particularly useful application of the TWBS technique may be prior to cement placement, when cement is pumped into narrow annular spaces with high ECD that may trigger induced fracturing and/or reopening of existing fractures. However, the interaction of the cement with a heated wellbore needs to be modeled and understood in order to avoid premature gelation and setting of the cement in the elevated temperature environment. In addition, it will be necessary to physically separate the exothermic fluid from the cement to avoid any contamination, e.g. Mg^{2+} contamination of Portland cement (which would lead to the adverse formation of Brucite, which in turn could lead to cracks and fissures in the cement) in case magnesium salts are used in the exothermic chemical system.

In addition, the effect of temperature elevation on the drilling / cementing / completion / stimulation / production load cases of the casing design with its various cemented and uncemented sections and open and/or trapped annuli needs to be well-understood. For instance, the heated water-based carrier fluid returning from bottom may heat upper hole and casing sections, and temperature elevation in section heated prior to cementing may lock in additional compressive stresses into the casing upon cement setting.

OBM/SBM Solidification

Introduction

A major cause of oil and gas well cementing failure is contamination of the cement slurry by drilling mud (Morgan and Dumbauld, 1952; Beach and Goins, 1957; Miranda et al., 2007; Aughenbaugh et al., 2014). Intermixing of Portland cement slurries and non-aqueous fluids (NAF), i.e. oil-based and synthetic based mud (OBM/SBM), will almost inevitably occur even under nearly ideal displacement conditions. Contamination of cement slurry by such NAFs is well-known to be detrimental to important cement slurry properties such as pumping time and compressive strength development. Studies have shown that Portland cement slurries are particularly sensitive to NAF contamination. With even a relatively small quantity of SBM contamination, Portland cement slurries can lose their compressive strength (Patel et al., 1999; Miranda et al., 2007; Aughenbaugh et al., 2014).

Targeting the contamination issue, a system named “universal fluid (UF)” was developed over 25 years ago. This system allowed for the conversion of a water-based mud (WBM) into a well cement (Nahm et al., 1994). A UF contains a hydraulic material (blast furnace slag, BFS), which can be activated to set up like a cementitious material when an alkaline activator is added (see Figure 8). The main advantage of a UF in comparison to an ordinary Portland cement system is its improved inherent compatibility with water-based drilling muds. With the use of a UF, any non-displaced drilling mud or mud filter cake may be incorporated into the cement, thereby largely eliminating the effect of contamination. The UF system, however, never found widespread industry acceptance after some promising early trials and field applications.

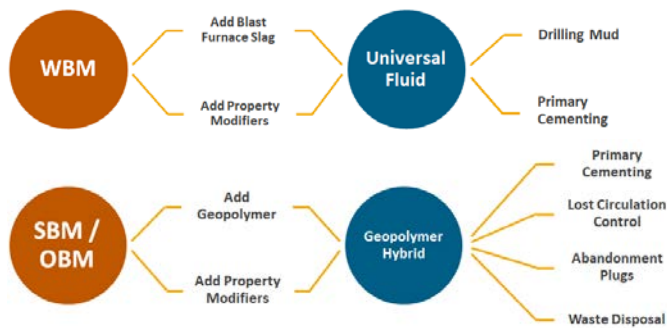


Figure 8 – {Top} process for creating a universal fluid by adding blast furnace slag to a WBM, which can be used to form a cementing material; (bottom) in analogy to the universal fluid, a geopolymer hybrid can be formed by adding AAM/geopolymer material to a OBM/SBM, which can be used for a variety of purposes, including lost circulation control.

Similar mud-to-cement conversion for NAFs is now possible through the use of the use of alkali-activated materials (AAM) as alternatives to Portland cement, as detailed below.

Chemical System

The AAM material discussed here is based on class F fly ash (FA), which can be activated with an alkaline activator, such as sodium hydroxide or a sodium silicate, to form a cementitious material (Aughenbaugh, 2013; Duxson et al., 2006; Provis and Deventer, 2009)). This material is also referred to as a “geopolymer”, a term used in the following. As shown Figure 9, the resultant material is a hydrated aluminosilicate (base components consisting primarily of the hydration products of SiO_2 and Al_2O_3), which is quite different from ordinary Portland cement (OPC), which is a hydrated calcium silicate (base components consisting primarily of the hydration products of SiO_2 and CaO).

Geopolymers have been extensively used in civil engineering applications, e.g. being poured into formwork for construction, but have only recently been considered for oilfield applications (Khalifeh et al., 2014). The fact that the industry has standardized on Portland as the cementitious material of choice is partly to blame for this. Moreover, getting the industry to consider any other material than OPC such as AAM for cementation purposes will require a major paradigm shift.

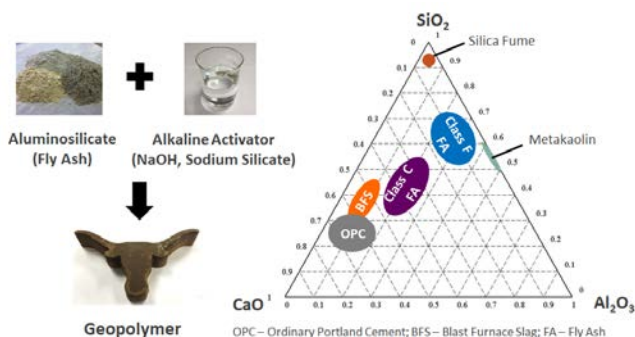


Figure 9 – {Left} cementitious geopolymer creation from fly-ash and alkaline activator; (right) chemical make-up of fly-ash, BFS and OPC in terms of base components CaO , SiO_2 and Al_2O_3 .

Laboratory Results

A practical objection against the use of geopolymers in oilfield practice is that 100% geopolymer slurries exhibit very high viscosity and are generally too viscous to pump downhole without exceeding pressure limits. Moreover, effective superplasticizer admixtures for reducing viscosity in Portland cement slurries, including lignosulfonate-, polynaphthalene- and polycarboxylate-based additives show either no – or very limited - effectiveness in geopolymer slurries. This, then, appears to be a clear roadblock for considering geopolymers for field use.

However, upon researching the contamination of OPC slurries by SBM and investigating the effect of SBM on geopolymer slurries, several interesting observations were made.

First, SBM contamination has a much stronger effect on loss of compressive strength of OPC than geopolymer. For instance, 10% by volume SBM field mud contamination of OPC leads to a loss of compressive strength of 70%, whereas the same level of contamination of a geopolymer slurry (Class F fly ash activated by an 8 M NaOH solution) only reduced strength by 40% (Liu et al., 2016). In addition, it was found that geopolymer slurries would still develop strength up to contamination levels in excess of 40% by volume, whereas OPC slurries typically did not develop any strength beyond contamination levels in the 15-20% range. The effect of SBM contamination on geopolymer strength is shown in Figure 10.

Secondly, it was found that SBM contamination increases the rheology of OPC, as shown in Figure 11 (Liu et al., 2016 & 2017b). With progressive SBM contamination, the OPC becomes more viscous until the point where it becomes essentially impossible to pump and displace. This observation has particular relevance to field cement jobs when intermixing of SBM and OPC happens behind casing: the result of this intermixing and associated contamination leads to OPC becoming non-movable, which in return can lead to an increase in displacement pressure, high ECDs in the annular space between casing and formation, and induced fracturing with associated losses. It was found that SBM contamination had the opposite effect on geopolymer slurries, with viscosity decreasing as the admixture of SBM (or OBM, which shows similar results) is increased, as shown in Figure 11.

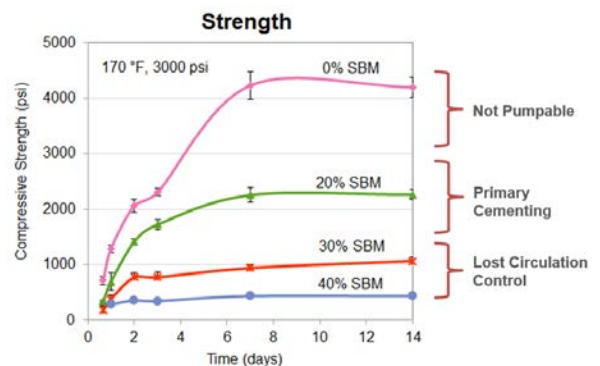


Figure 10 – Compressive strength behavior of Class F fly ash geopolymer as a function of SBM admixture (% by volume).

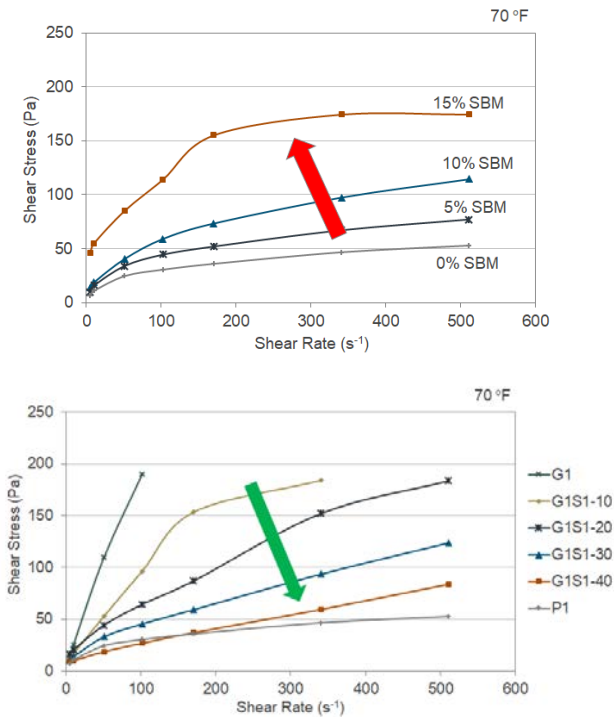


Figure 11 – {Top} rheogram at 70°F of shear stress vs. shear rate for OPC with admixture of SBM (% by volume); note the increase in viscosity with increasing levels of SBM, as shown by the red arrow; (bottom) similar rheogram for Class F fly ash geopolymer, showing the reverse trend (green arrow) with reduced viscosity with increasing levels of SBM (notation: G1S1-30 = geopolymer G1 with SBM type S1 at 30% by volume admixture; P1 = OPC).

It is thus seen that forming a geopolymer hybrid, i.e. a geopolymer with OBM/SBM added to it (Liu et al., 2016 & 2017b), solves the viscosity challenge and makes geopolymer slurries pumpable. In addition, it is noted that temperature increase improves the viscosity of geopolymer slurries even further, whereas the viscosity of OPC slurries is usually increased (Liu, 2017c).

Moreover, as can be seen in Figure 10, it is possible to “tune” the strength of the geopolymer hybrid by controlling the percentage of OBM/SBM mixed in with the geopolymer material. In particular, smaller levels of admixture (on the order of 20% by volume) appear to create higher strength materials that are suitable for primary cementation and for use in abandonment plugs. It was recently discovered that such hybrids have spontaneous self-healing capabilities after yielding/cracking, making them well-suited for abandonment purposes (Liu et al., 2017a). Higher levels of admixture (on the order of 30-40% by volume) generate materials that have a strength that is typically several hundred psi, which appears to be well-suited for lost circulation control. In setting cement plugs for lost circulation mitigation, it is imperative that the plug material does not generate too high a compressive strength which would allow it to act as a kick-off plug upon re-drilling the loss section. This could lead to unwanted side-tracking and a repeat of the original loss problems in native formation not protected by the plug treatment.

In addition, it is noted that admixing OBM/SBM at any concentration less than 50-60% can be used for consolidation of the mud, in particular for waste disposal purposes. Figure 12 shows two examples of SBM and OBM waste muds admixed with geopolymer at 20% by volume that were effectively consolidated.



Figure 12 - Pictures of geopolymer hybrid samples containing {left} 20% SBM used in US horizontal well drilling operations and {right} 20% OBM used in offshore Thailand drilling operations.

Considerations for Field Applications

It is well-known that using OPC cement plugs to battle severe lost circulation in the field has a low probability of success, particularly when OBM/SBM is used as the drilling fluid (Nelson and Guillot, 2006). The reason for this is contamination. As indicated, when OPC gets contaminated by OBM/SBM at the 15%-20% by volume level, it will develop no strength and will lose the ability to stop losses. Such contamination is very likely when pumping OPC in induced or natural fracture systems that contain large volumes in OBM/SBM from the loss event. Moreover, the cement will not effectively bond with fracture surfaces that have been effectively wetted by OBM/SBM. The OBM/SBM consolidation technology using geopolymers presented here offers a superior alternative. Geopolymer is inherently compatible with OBM/SBM, and can consolidate these muds in downhole fracture systems. Recent work has shown that geopolymer hybrids can bond to oil-wet surfaces (Liu et al., 2017a). They therefore appear to be good candidates for mitigating and treating losses in induced and natural fracture systems where conventional loss circulation methods fail.

As with all cementing material, the use of geopolymers and geopolymer hybrids requires good QAQC, particularly when it comes to fly-ash and activator materials. Note that fly ash is currently not standardized to the same extent that OPC is, so specific types and batches of fly ash will require dedicated testing with actual activators and OBM/SBM admixtures that will be used in field application. API cement test protocols can be followed, in analogy to OPC testing. Note that ultrasonic cement analyzer (UCA) testing requires special attention, as current travel time correlations built into industry UCA equipment do not apply to geopolymers. UCA correlations development for geopolymers is a current area of research.

Conclusions

This paper highlights two recent innovations in lost circulation mitigation and control: thermal wellbore strengthening through managed temperature drilling, and OBM/SBM consolidation using geopolymers. Both technologies are enabled by novel fluid chemistries.

Thermal wellbore strengthening makes use of chemicals that can react in an exothermic fashion when contacted by water. The exothermic reaction can be delayed by coating of the chemical particles, thereby allowing for sufficient circulating time to transport to them to the zone(s) that are lost circulation-prone. Once the exothermic reaction commences, heat is generated which can be used to raise the temperature in near-wellbore zones. This temperature raises the tangential stress in the near-wellbore, which in turn raises fracture initiation and propagation pressures, thereby mitigating losses. Good candidates for the exothermic reaction appear to be dissolution reactions in water of anhydrous salts of CaCl_2 , CaBr_2 , MgCl_2 and MgBr_2 . The temperature increase that these materials can generate may increase near-wellbore tangential stress by several hundred psi, depending on rock material properties, as indicated by preliminary modeling studies. A particularly interesting field application for this technology is pumping a thermal wellbore strengthening treatment prior to cementing to raise the threshold for losses during cement placement, thereby helping to lift the cement column and establish the required top of cement, thus helping to guarantee zonal isolation.

OBM/SBM consolidation uses alkali-activated materials, also referred to as geopolymers, to generate cementitious media that can be used for a range of oilfield applications, including primary cementing, lost circulation treatment, well abandonment plug cementing, and waste consolidation. Geopolymers can withstand high levels of contamination by OBM/SBM, and can still develop strength at these conditions. Geopolymers by themselves are too viscous to pump, with no superplasticizers readily available for them, but OBM/SBM admixture lowers their viscosity and makes such geopolymer “hybrids” pumpable. A particularly interesting potential field application is using geopolymer hybrids for lost circulation control in natural or induced fracture systems drilled with OBM/SBM, where conventional lost circulation methods frequently fail.

It is hoped that this paper, dedicated to new approaches to lost circulation, will help to bring innovation and new thinking to the ever-present lost circulation challenge.

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Glossary

<i>AAM</i>	= Alkali Activated Material
<i>API</i>	= American Petroleum Institute
<i>BFS</i>	= Blast Furnace Slag
<i>CBHP</i>	= Constant Bottom Hole Pressure
<i>ECD</i>	= Equivalent Circulating Density
<i>FA</i>	= Fly Ash
<i>LCM</i>	= Lost Circulation Material
<i>MPD</i>	= Managed Pressure Drilling
<i>MTD</i>	= Managed Temperature Drilling
<i>NAF</i>	= Non Aqueous Fluid
<i>OBM</i>	= Oil Based Mud
<i>OPC</i>	= Ordinary Portland Cement
<i>PMCD</i>	= Pressurized Mud Cap Drilling
<i>QAQC</i>	= Quality Assurance / Quality Control
<i>R&D</i>	= Research & Development
<i>SBM</i>	= Synthetic Based Mud
<i>TVD</i>	= True Vertical Depth
<i>TWBS</i>	= Thermal Wellbore Strengthening Drilling
<i>UCA</i>	= Ultrasonic Cement Analyzer
<i>UF</i>	= Universal Fluid
<i>WBS</i>	= Well Bore Strengthening

Nomenclature

<i>c</i>	= specific heat capacity, kJ/kgK
<i>E</i>	= Young’s modulus, Pa
<i>k</i>	= thermal conductivity, W/mK
<i>S</i>	= volumetric heat generation, kW/m ³
<i>t</i>	= time, s
<i>T</i>	= temperature, K
ΔT	= temperature difference, K
<i>U</i>	= velocity vector, m/s
<i>z</i>	= vertical distance, m
α	= thermal expansion coefficient, 1/K
ν	= Poisson’s ratio
ρ	= density, kg/m ³
σ	= stress, Pa
θ	= tangential component

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