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Alternative Cement Program for the Surface Casing in the Skarv Field

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Abstract

A phenomenon called *Shallow Water Flow* (SWF) was encountered when drilling the top sections at the Skarv field, causing difficulties when cementing the surface casing. This thesis describes a proposed cement program with conventional cement which has shown through testing to be applicable to deal with annular fluid migration such as SWF. This is done successfully by designing; 1. gas tight slurries with properties that is acknowledged to be resistive against SWF; 2. the lead slurry to keep hydrostatic pressure until the tail slurry attains enough strength to prevent annular fluid migration.

Introduction

The Skarv field, which is located offshore west of Sandnessjøen, Norway, is a gas and oil field which will be operated by BP. The chosen concept for the field is subsea wells in several templates, together with a massive FPSO (Floating Production, Storage and Offloading) unit. Early in 2010, the Skarv drilling operations started, and is still an ongoing project. The drilling operations were planned to be performed in batches, meaning that the top hole sections will be drilled and completed sequentially (for all the wells that are situated on the same template) before drilling is continued down to reservoir section.

These batch programs have been executed successfully with respect to time and cost, because of the positive effect of a steep learning curve. However, there have been complications due to Shallow Water Flow (SWF). Before the drilling project started, the probability for Shallow Gas/SWF zones was considered to be low, but wells on several templates have encountered SWF. The complications have not been during the drilling phase, but after the surface casing have been cemented. After the cement has set, SWF with associated gas has been observed to come from the annulus between the conductor and the surface casing. Cement bond logs indicates fairly good cement in this annulus from target depth up to surface, but it has been assumed that there has to be some channeling in the cement for which the water/gas flows. The origin of the SWF is assumed to be around 900mTVD MSL, and seem to be very local since wells in neighboring template slots indicates <u>no</u> SWF.

Normal Norcem class G cement was used until SWF was encountered. Then foam cement was used to cement these surface casings. Foam cement is considered to be a good solution for cementing in zones with shallow gas/SWF. However, using foam cement is more expensive, and there is additional risk associated since there is more equipment involved in the cementing job that could fail. In any case, cementing in these zones is considered to be a challenge

Being that cement is a primary well barrier element, it is important that it is implemented successfully to ensure the integrity of the well. Using parameters now known from the field, testing an alternative conventional g-cement recipe has been performed to investigate if it is qualified for cementing the surface casing combating SWF.

Shallow Water Flow

Shallow water flow originates from sand reservoirs with abnormal pore pressure that lie under a seal at shallow depths. There are two generalized models for explaining this abnormal pore pressure [1]. According to the first model, *Compaction Disequilibrium*, the abnormal pore pressure is the result of a rapidly deposited overburden over an established seal. The escape of water in the porous sediments is retarded by the seal. The rapidly deposited overburden transmits pressure to the sediments underlying the seal faster than the seal allows pore fluid to escape. The faster the sedimentation rate above the seal, the higher pore pressure exists in the sand reservoir under the seal.

The second model, *Differential Compaction*, has much of the same mechanisms. However, in this situation the sand reservoir is incased in silty shale which lies below a seal. Laterally for the sand body the silty shale lays under a thick layer of sediments that have been deposited recently, i.e a river delta. These deposits above the seal transmit a higher overburden than the thinner layer of deposits above the sand reservoir. Because of the seal the higher overburden charges the silty shale with pressure which is transmitted laterally to the encased sand reservoir. In other words, the compaction of the silty shale makes the pore fluids escape to the sand reservoir, increasing its pore pressure.

In the Skarv area the mechanism for the increased pore pressure is believed to be a version of compaction disequilibrium. Very quick sedimentation of shale that was unable to dewater during compaction generated overpressure. These pressures communicated to surrounding silts and sands. Additionally, it looks like these over-pressurized sands have been further prevented to dewater by the presence of an over-compacted layer above. This over-compacted layer is due to ice loading, resulting in a compaction equivalent to a deeper depth. [2]

When Shallow water flow has been encountered during flow checks, it usually has happened at a depth of 900mTVD MSL or below, depending on template location. The exception is one template where SWF was encountered at approx. 700mTVD MSL. So it is clear that the flow may come from several depths in the basin.

The Problem

When the SWF has been encountered during drilling, it has been easily solved by killing it with weighted water based mud. The problem has been that SWF has been detected after the surface casing has been set. The flow is seen coming from the annulus between the 18.7" surface casing and the 30" conductor casing. Flow in this annulus has even been detected in wells that showed no SWF during the drilling phase. It might have been that the pore pressure from the SWF zone was very close to the well pressure so that the flow would have gone unnoticed during the flow checks. Another possibility is that the drill fluid, which was seawater and viscous sweeps, containing cuttings was enough to suppress the SWF.

When there was no sign of SWF, the open hole was circulated two times bottoms up, and then displaced with 1.30sg KCL mud. This circulation may have washed out sediments at the problem zone, widening the borehole. This lowers the annular velocity of circulating fluids and could have resulted in an improper displacement of the KCL mud prior to cementing, leading to channeling in the cement, or in general, failure of the cement to seal the annulus. Practices of hole cleaning and mud displacement is an important part of getting a successful cementing of the casing, but will not be investigated here.

The main focus of this Thesis is the design of the cement itself and what properties it should have to prevent annular fluid migration. Annular fluid migration has three distinct root causes which all must be satisfied to take place:

1. The annulus pressure must fall below the pore pressure of the risk zone
2. There must exist space in the annulus for which the formation fluid can enter
3. A path is present in the annulus through which the fluid can migrate

The factors that contribute to the different root causes can be different at different time frames. This is because of the physical nature of cement which progresses from liquid slurry to an impermeable solid. During the transition from liquid to solid it has a permeable gel that is deformable. Because of this shift in physical state, it is convenient to categorize the time frames to better address which factors contribute to the annular flow:

1. Immediate (during placement): Minutes → Hours
2. Short-term (time from top wiper plug bumped to the cement sets): Hours → Days
3. Long-term (post-setting): Days → Months/Years

Table 1: Factors responsible for annular fluid migration [3]

	Annular Pressure ≤ Pore Pressure	Space for Entry	Path for Migration
Immediate	Hydrostatic underbalance	Fluid displaced from wellbore	Fluid displaced from wellbore
Short term	Fluid loss	Fluid loss	Slurry permeability
	Gel strength development	Free fluid	Slurry permeability
	Chemical shrinkage of cement	Chemical shrinkage of cement	Filtercake permeability
	Annular bridging	Slurry porosity	Filtercake permeability
	Annular packers	Slurry porosity	Filtercake permeability
Long term	Chemical shrinkage of cement	Chemical shrinkage of cement	Microannulus
		Mud channel	Mud channel
		Free fluid	Free-fluid channel
	Strength development of cement	Dehydrated filtercake	Dehydrated filtercake
		Bulk shrinkage of cement	Bulk shrinkage of cement
			Low cement tops
			Cement sheath mechanical failure

Immediate annular fluid migration is prevented by keeping hydrostatic overbalance in the well during the cement placement. In the *long-term*, annular migration is usually a result of a combination of factors like deterioration (chemical shrinkage) of the cement, microannulus or failure because of mechanical forces. See Table 1 for a list of factors contributing to initiate annular flow at different time frames. The annular flow that has happened in the Skarv field must be categorized to be a *short-time* (post-placement) issue since the SFW was discovered only hours after cement placement. Short-term fluid migration is perhaps the most complex to understand, difficult to predict and problematic to prevent. However, it is believed that the primary driver is the decay of hydrostatic pressure exerted by the cement as it gels up during its transition from fluid to solid. The cement in this thesis is tested to see if it holds properties that are believed, in the industry, to be crucial to prevent annular fluid migration. [3]

Usually a conventional cementing job consist of a lighter lead cement to ensure the hydrostatic pressure doesn't exceed the fracture pressure of the well, and a short interval of a heavy tail cement for extra support around the casing shoe. When cementing the surface casing with conventional cement in the Skarv field, they have had difficulties preserving enough hydro-static pressure on the tail cement while it was setting up. This means hydrostatic pressure exerted on the tail by the lead is partially lost before the tail cement (also covering an abnormal pressure zone) started to set, creating an underbalance in the well. Pressurized formation fluid may now enter the well and perhaps form a migration route, through the still deformable gelling lead slurry, up to a lower pressure zone (with a lower fracture pressure) or up to surface. Therefore, BP Norway had a desire to test a cement program, using conventional G-class cement, where the lead was designed to keep hydrostatic overbalance until the tail had achieved enough strength to prevent annular fluid migration such as shallow water flow.

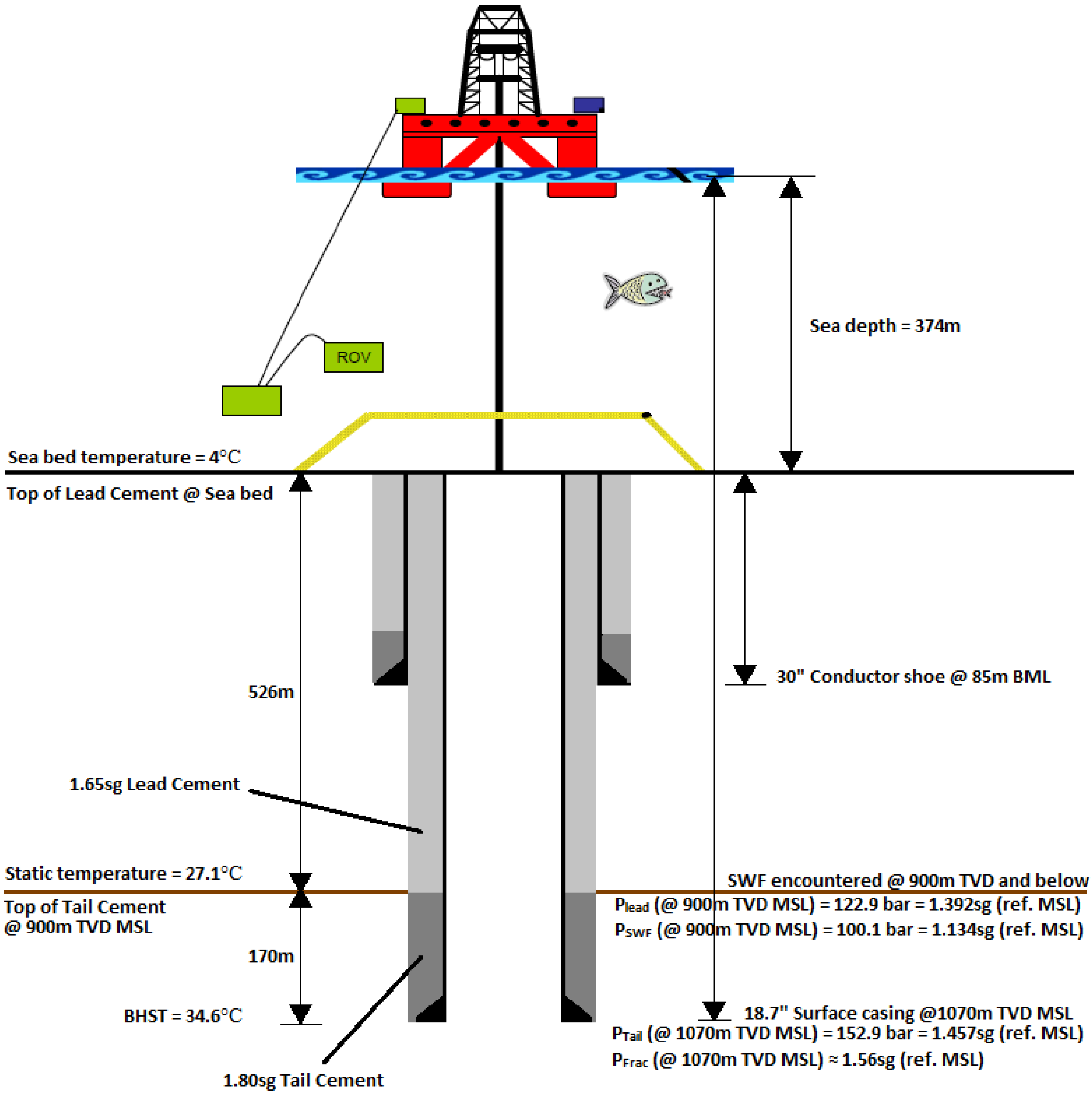


Figure 1: Schematics over the Base Case parameters used to test the cement slurries in question. The pressures listed are; the hydrostatic pressures exerted by the cement immediately after placement (lead/tail), fracture pressure gradient at the 18.7" casing shoe (frac) and the assumed shallow water flow zone pore pressure gradient (SWF). The brown line indicates 900m TVD MSL. (E.S. Keeling)

Base Case

As the SWF phenomenon has happened in wells at every template a base case has been created based on the depths and temperatures experienced in the area. This base case will be the basis for how the testing of the cement has been performed. See Fig. 1 for visualizing the base case. The sea depth in the area is varying between 323m to 392m depending on template location. Here the sea depth chosen is 374m (matching one of the templates). Further the 30” conductor shoe is landed and cemented at approximately 85mbelow mud line (BML). The 18.7” surface casing is landed 1070mTVD MSL and covers the interval experiencing shallow water flow. The interval below 900 TVD MSL to section TD (total depth) of 1070mTVD MSL is assumed to be the origin of the SWF/gas. The imagined top hole section is assumed to be vertical for simplicity of calculations. The actual wells have a max. inclination of 20 degrees, but the vertical depths mentioned holds true and therefore valid for hydrostatic pressure calculations.

The base case is assuming that the 1.80sg tail cement is covering the problem interval (900 – 1070mTVD MSL) and the 1.65sg lead cement will cover the rest of the surface casing up to

mud line. This means that the tail interval will be 170m. This could have been a fracture pressure issue at the 18.7” casing shoe, but the hydrostatic pressure is well within the fracture pressure prognosis of ≈1.56sg (see Fig. 2) [4], and because of the large casing diameter friction pressure shouldn’t be a problem with respect to ECD (Equivalent Circulation Density) [5]. The reservoir for the origin of the SWF is assumed to have a pore pressure (P_{SWF}) of 1.134sg (ref.
point at MSL), which was the equivalent mud weight (EMW) required to kill the flow experienced during drilling one of the wells. This is actually a bit on the high side since the well showed no flow when using 1.116sg EMW, but 1.134sg was used for drilling the rest of the 24” section and no flow was experienced during that time. In other words this was enough to suppress any SWF zones further down the basin in that section.

The following true temperature profile prognosis of the Skarv area is used [6]:

- Skarv True Formation Temperature = 128.4 °C at a reference depth of 3413m TVD MSL
- Skarv Overburden Temperature Gradient = 4.40 °C/100m
- Skarv Reservoir Temperature Gradient = 2.5 °C/100m (i.e. in the reservoir, not for the overburden, starting from 2940m TVD MSL)
- Uncertainty in predictions = ± 4 °C
- Seabed temperature = 4 °C

This results in a bottom hole static temperature (at 18.7” casing. shoe) of 34.6 °C and a static temperature of 27.1 °C at 900m TVD MSL (see Fig. 3).

The Cement

As mentioned, the cement design consists of using a heavy tail slurry and a lighter lead slurry. These slurries that have been tested was designed by Baker Hughes (previously known as BJ Services) to be gas tight slurries. Since gas is harder to prevent migrating within the cement matrix itself, gas tight cement slurries are also a solution for preventing migration of liquids, such as shallow water flow. The slurries are based upon standard Portland class G cement. The class G cement used in the Skarv field has been produced by Norcem and

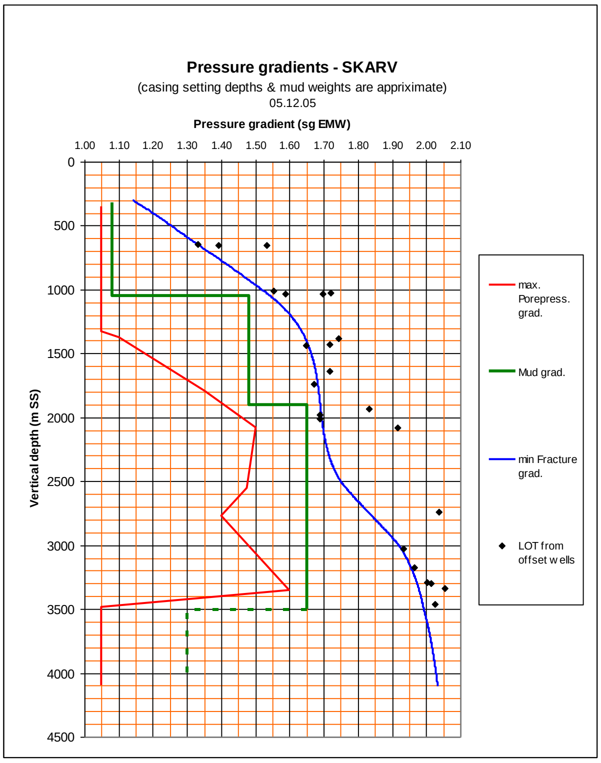


Figure 2: Pressure gradienst over the Skarv area. Shows fracture gradient (blue), pore pressure gradient (red) and proposed mud weight scheme (green) [4]

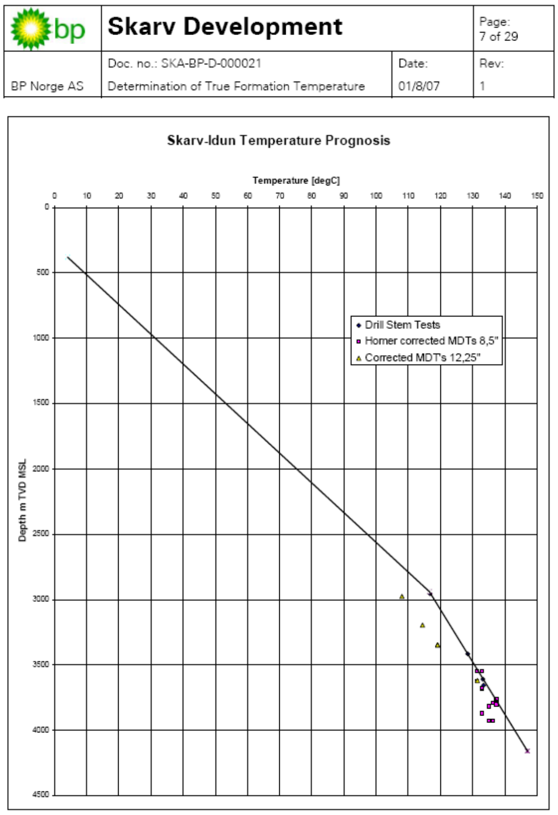


Figure 3: Skarv area temperature prognosis. The bend at 2940m TVD MSL shows the beginning of the reservoir temperature gradient. [6]

is considered to have larger variations in properties from batch to batch delivered.

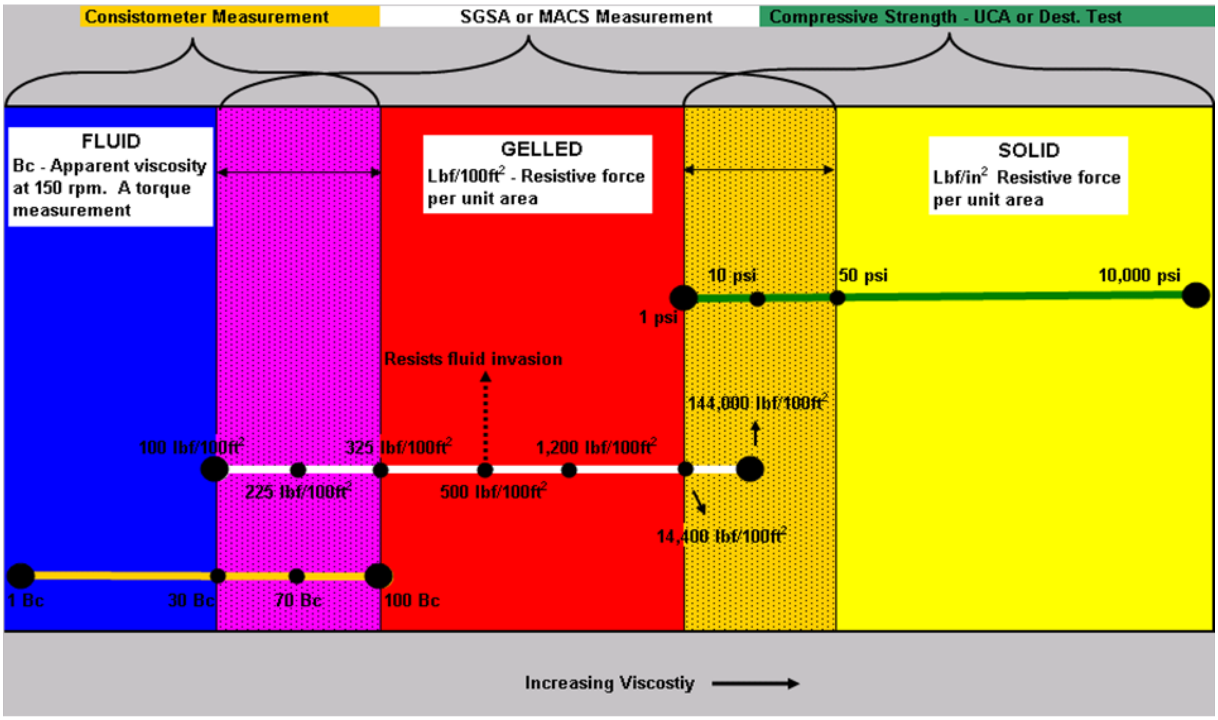


Figure 4: Chart comparing the different viscosity units used in different tests. The values on the blue background might be hard to read: Starting from the left the two values on the yellow line are 1Bc and 30Bc respectively. The first value on the white line on left is 100 lbf/100ft^2. (Baker Hughes)

Therefore the different additives used also must vary in amounts. In other words Norcem cement usually requires more testing for tuning the cement slurry to exhibit the same properties from batch to batch. Because of the high production temperature of 130-140°C, 35% BWOC (by weight of cement) of silica is required to be added in the cement slurries to prevent long term strength retrogression.

Properties that the cement should possess are as follows:

- Low fluid loss (<50 ml/30min)
- Right Set Angle (RAS) behavior
- Short transition time
- Minimal permeability
- No free water
- Minimal cement shrinkage

Fluid loss is when the aqueous phase of the cement slurry escapes into the formation leaving solids behind. Some fluid loss will always filtrate to the formation, but controlling it to a minimum prevents a reduction in hydrostatic pressure because of annular bridging of solids, increased slurry gelation and/or reduction in slurry volume. Fluid loss may also create a space within the cement matrix that can be occupied by formation fluids. A fluid loss of maximum of 50 ml/30min is considered a minimum requirement for preventing annular fluid migration. [3]

Right set angle (RAS) behavior on the cement is defined as a very quick increase in slurry viscosity at the end of the designed pump time. In other words the cement thickens to a low permeable paste/gel quickly after the cement placement. The unit for this type of thickening test is in Bearden units (Bc), where values over 30Bc is considered unpumpable, and the test ends at 100Bc. RAS behavior will show a constant low viscosity (<30Bc) followed by a very sharp increase in viscosity (<30Bc →100Bc), creating an almost 90° bend on a graph measured against time. [3, 7]

Probably the most important design parameter for preventing SWF has to do with how the cement develops its gel strength. After the cement is pumped in place it goes static and starts to develop gel strength. With time this gel starts to become self-supporting, resisting the force placed upon it, and thus the hydrostatic pressure starts to decrease. As mentioned this is the critical time for when the cement is most accessible to fluid invasion, and should be kept to a minimum. The term *zero gel strength time* is defined as the time it takes the cement to achieve the static gel strength (SGS) of 100 lbf/100ft^2. This value equals the viscosity of 30Bc (see Fig. 4 to compare different units). At 500 lbf/100ft^2 the gelled cement is recognized by the industry to be resistant against fluid invasion. The time it takes the SGS to reach 500 lbf/100ft^2 from 100 lbf/100ft^2 is called the *transition time*. The old industry accepted theory was that the cement was considered to fully transmit hydrostatic pressure until 100 lbf/100ft^2, hence the term zero gel strength. Thus the transition time was also the critical time. However, this was an over-simplified model.

Today, instead of using the zero gel strength (ZGS), a new critical parameter has been introduced called *critical gel strength* (CGS). This parameter states that when the hydrostatic pressure in the well (at the depth of the SWF zone) drops below the formation pore pressure, only then will it be acceptable to fluid invasion. To explain the model one has assumed the cement slurry behaves like a virgin sedimentary soil that undergoes consolidation. The state of stress can be described by Terzaghi's law [3]:

$$\sigma_c = \sigma_c' + p_c \tag{1}$$

where
σ_c = total stress exerted by cement at given depth
σ_c' = intergranular shear stress related to gel strength delopment
p_c = hydrostatic pressure (interstitial pore pressure)

Initially the σ_c' is equal to zero since no gel strength has been developed. Since the total stress (σ_c) is constant, any change in the hydrostatic pressure (p_c) leads to an equal change in intergranular shear stress ($\Delta\sigma_c' = \Delta p_c$). The critical point is when hydrostatic pressure exerted by the cement drops to the shallow water flow zone pore pressure ($p_c = p_{SWF}$). This decrease in hydrostatic pressure by the cement is equal to the overbalance (Δp_{ob}) in the well (eq. 3). By finding out how much the gel strength increases until the overbalance in the well becomes zero will determine how much additional gel strength the cement must achieve to be resistance against fluid invation. This is the critical gel strength (ΔS_{gel}). [3, 8]

$$\Delta\sigma_c' = \frac{4L \times \Delta S_{gel}}{d_o - d_i} = \Delta p_{ob} = p_{sw} + p_c - p_{SWF} \tag{2}$$

where
$\Delta\sigma_c'$ = change in cement shear stress (Pa)
ΔS_{gel} = change in cement gel strength (Pa)
Δp_{ob} = well overbalance at swf zone depth (Pa)
p_{sw} = hydrostatic pressure by a column of seawater (Pa)
p_c = hydrostatic pressure by a column of cement (Pa)
p_{SWF} = pore pressure in SWF zone (Pa)
L = length of cement column (m)
d_0 = open hole diameter (m)
d_i = outer diameter of casing (m)

Rearranging equation (2) to express the critical gel strength, and adding a conversion factor for different units results in

$$\Delta S_{gel} = 300 \times \frac{\Delta p_{ob}(d_o - d_i)}{4L} \tag{3}$$

were the units now are as followed:

ΔS_{gel} (lbf/100ft^2)
Δp_{ob} (psi)
L (ft)
d_0 and d_i (inches)

The transition time now becomes the time the cement develops 500 lbf/100ft^2 from the CGS, which now is a variable defined by water depth, depth of SWF zone below mudline, cement density and SWF zone pore pressure. In other words transition time is now time elapsed between CGS and 500 lbf/100ft^2 (still considered to be a static gel strength sufficient to mitigate fluid flow). [8]

Free water (free fluid) is undesirable since it creates space for entry and a migration path for formation fluids. Using a cement slurry that exhibit no free water is especially important when cementing in highly deviated or horizontal well. [3]

Having an impermeable cement sheath when hardened goes without saying as its function is to provide zonal isolation, but having a *low permeability* during the critical transition from liquid to solid is equally as important when addressing shallow hazards. If the matrix created within the gelling cement is prone to develop a relative high permeability, formation fluid that invades the cement pores can prohibit the pore throats from closing when the cement hydrates, providing a migration path after the cement has hardened. [3]

Chemical shrinkage is a result of the chemical reactions taking place in the cement when setting. Because the initial reactants are bigger than the end products, a reduction of the total cement volume occurs. It is important to point out that the total volume shrinkage is the sum of a change in bulk volume *and* internal matrix contraction. Reduction of the hydrostatic pressure is a result of the chemical shrinkage within the cement matrix caused by the chemical reactions and fluid loss. [3]

The Additives Used

For the cement to acquire the properties that are beneficial like the ones listed above, additives must be added. The additives used are all liquid, making the procedure of mixing the cement easier. In other words, no dry blending prior to mixing is needed. Six different additives were used.

Silica

This additive consists mainly of two ingredients; silica flour and microsilica (silica fume). As mentioned, the production temperature in the Skarv area requires silica to prevent strength retrogression, and is largely the function of the silica flour. If normal Portland class G cement is subjected to temperatures above 110 °C, it is subjected to metamorphism to create a more crystalline and dense material. As a consequence the cement matrix shrinks, resulting in a decrease in compressive strength and increased permeability, detrimental to mechanical casing support and zonal isolation. By adding 35% silica BWOC, a mineral called tobermorite is formed which preserves the strength and low permeability. The other ingredient, microsilica, has a fluid invasion blocking function. Microsilica is a byproduct when producing silicon/ferrosilicon alloys. Microsilica is spherical particles that have an average size of 0.15µm, which is ± 100 times smaller than Portland cement. Because of this, it is believed its blocking function is that the small silica particles packs in between the cement particles, greatly reducing the pore throats, maybe especially at the initial cement filtercake in the formation-cement interface. [3, 9]

Microsilica

To make the lower density lead slurry to become “gas tight” additional microsilica must be added to the slurry.

Fluid-loss Agent

The agent used is of the water soluble type. It prevents fluid loss by increasing the viscosity of the aqueous phase, but more importantly reducing the filtercake permeability. The filtercake permeability reduction is believed to be a result of a combination of two separate mechanisms; 1. weakly bonded colloidal aggregates of polymer molecules get wedged in the filtercake constrictions, and 2. the polymers absorbs onto the cement grain surfaces and thus reduces the pore size. [3, 10]

Dispersant

Because the cement slurry contains high concentration of solids, and viscosifying elements such as fluid-loss agent, dispersant is used to achieve the proper rheological properties. This generally means reducing the viscosity of the cement without resulting in free water sedimentation/segregation/settling of solids. The dispersant lowers the viscosity by reducing the surface tension between the particles in the slurry. The dispersant type used is sulphonated organic polymers. [3, 10]

Retarder

An additive that delays the initial setting (thickening) of the cement to ensure sufficient time provided to pump the cement in place. There are several chemical classes of retarders, but type used are calcium/sodium lignosulfonates. [3, 10]

Foam Preventer

Additives used in the cement can cause foaming during mixing. Foam is unwanted because it can lead to erroneous density measurements during in-field mixing of the cement because of the trapped air in the slurry. When the slurry is pumped down the air is compressed increasing the density to an unwanted level. Slurry gelation is also an undesirable consequence due to excessive foaming. The foam preventer operates by lowering the surface tension in the foaming system, thus collapsing the air bubbles. [3]

The Tests

Several tests have been performed to determine the cements ability to project the properties that has been stated as important to prevent shallow water flow. Because of the limited equipment available at the university, two of the tests have been performed externally by Baker Hughes. The tests performed are:

- Rheology
- Thickening time (TT)
- Compressive strength (Ultrasonic Strength Analyzer (UCA))
- Static gel strength (SGS)
- Gas flow model test

The three top listed are API standard tests, while the SGS test is an industry accepted test. The gas flow model test may be company specific.

The procedure for the tests can be categorized as followed:

1. Preparation
2. Mixing of slurry
3. Conditioning of slurry (if applicable)
4. Testing

For API standard tests, procedures will only be referred, but deviations from standard will be announced. Common for all the tests are the mixing procedure of the cement. All of the additives are mixed in the mix water (distilled water), before cement is added. Using syringes the roughly volumes of the additives are measured, and then a weight is used to measure the accurate amounts, preferable within ±0.03 grams (see Fig. 5). The specific mixing procedure for the slurries used are as followed:

1. Add silica, microsilica and foam preventer to the water.
2. Mix for 20sec. at 4000 rpm
3. Add dispersant while mixing
4. Mix for 20sec. at 4000 rpm
5. Add fluid loss agent while mixing
6. Mix for 20sec. at 4000 rpm
7. Add cement, preferable within 15sec while mixing at 4000 rpm
8. Mix for 35sec. at 12000 rpm
9. Check cement for “lumps”, additional mixing may be required

Figure 5: Left: Examples of syringes used. The weight used measures down to 0.01 grams. Right: A Chan 85 rotational viscometer used for rheology testing. (E.S. Keeling)

Figure 6: The pressurized consistor used for testing thickening time at constant pressure (E.S. Keeling)

Rheology

To make sure that the slurry is stable, rheology testing is performed. The slurry is stable when no sign of settling or excessive gelling occurs. The testing was performed on equipment shown on Fig. 5. For procedure please refer to the API standard [11] chapter 12.1 – 12.5.

Thickening Time

The thickening time (TT) test was performed on a pressurized consistometer shown in Fig. 6. For procedure please refer to the API

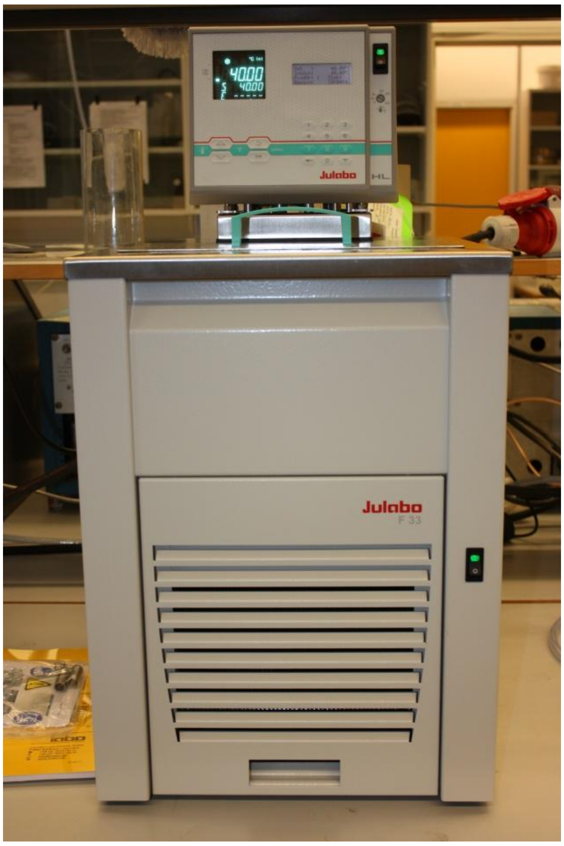


Figure 7: A programmable Julabo heat/cooling bath used for simulating temperature during thickening time tests and compressive strength tests. (E.S Keeling)

standard [11] chapter 9. Because of the simplicity of the equipment used, tests have been performed with constant bottom hole pressure. Instead of using the drilling fluid pressure gradient (API standard), cement gradient has been used as this is the actual maximum pressure experienced by the cement. Calculations show that maximum pressure experienced for the lead cement is 150.4 bar, while this value for tail cement is 152.9 bar. Unfortunately the consistometer used was unable to keep such accurate pressure values, but the pressure was generally kept above 150bar. The bottom hole circulating temperature was simulated by Baker Hughes to be 24°C, which is the temperature used when testing TT. The temperature is controlled by an external heat/cooling bath unit (Julabo) seen on Fig 7. The viscosity, pressure and temperature are monitored by the software LabVIEW 7.1 by National Instruments.

Compressive Strength (UCA-testing)

The UCA apparatus is a non-destructive compressive strength analyzer (Fig. 8) and consists of a heat/cooling bath that surrounds the test cell. The test cell consists of a thick

Figure 8: The Ultrasonic Cement Analyzer used for compressional strength tests. (E.S. Keeling)

Figure 9: Details of the test cell that is installed in the UCA apparatus during testing. (E.S. Keeling)

steel cylinder, in which the inner wall is conical to ease the disposal of the cement after the test is completed. The open cylinder is closed by a top and bottom cap, of same material as the cylinder, which screwed on. An O-ring on both caps has the sealing function and is kept in place by support ring(s) (two support rings on top cap). In the middle externally on both caps the space is provided for the sender (bottom) and receiver (top) ultrasonic probes. The top cap has additional openings for a temperature probe and entrance for the hydraulic pressure (test pressure) provided by pressurized water. See Fig. 9 for test cell details. The water is pressurized by an actuator driven by air pressure. The same external heat/cooling bath unit used for the TT test is used to control the temperature of the UCA cell. The software used to monitor the ultrasonic transit time, the temperature and the compressive strength is called Chandler Data Acquisition and Control System (ver. 2.0.152) by AMETEK Chandler Engineering. The pressure is monitored by LabVIEW 7.1 by National Instruments.

Before the cement is prepared, the inside of the steel cylinder/caps/O-ring is saturated with grease to seal and to prevent the cement to bond with the inner wall. The bottom cap is then installed, and the cell is now ready for the cement slurry. The cement is mixed as described earlier before it is conditioned for 20 min in an atmospheric consistometer. The conditioning is to simulate a minimum of pumping energy [12]. The cement is poured into the cell and a measuring device is used to ensure the correct amount. The same measuring device is then used to pour the correct amount of distilled water on top of the cement to ensure no air is trapped inside the cell when installing the top cap. The top cap is installed. Some of the distilled water should come out of the top openings to indicate that no air is actually inside the test cell. The cell is then loaded into to the UCA apparatus, making sure the bottom ultrasonic probe slides neatly into the bottom cap. The temperature probe and the pressure tube are connected to the two top cap openings, and the top ultrasonic probe is connected. The cell is then pressurized to the desired test pressure. The heat/cooling bath is programmed to hold the BHCT for 1 hour, then to increase the bottom hole static temperature (BHST) in 4 hours and to hold this temperature until the end of the test (48 hours or more).

When the test has ended, bleed down the pressure, disconnect the temp. probe, pressure connection and the probe. Pick up the cell from the UCA apparatus and remove the top and bottom cap. To remove the hardened cement, place the cylinder up-right and try to hit it out with a hammer and a steel rod. If unable to release cement, use a hydraulic pressing machine to push the cement free (preferable method).

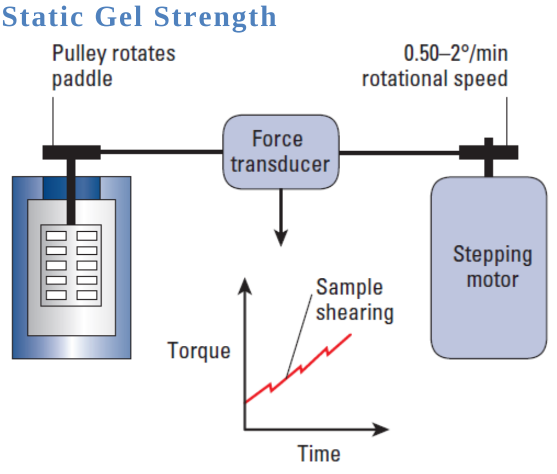


Figure 10: Conceptual drawing of the MACS analyzer in Gel Strength mode. [3]

This test was done externally by Baker Hughes' lab facilities in Tomball, USA. The slurry is mixed according to announced procedure. The mixed slurry is poured into a prepared MACS (Multiple Analysis Cement System) analyzer cup, and placed in a MACS analyzer machine. The machine is ramped up to the desired pressure and the desired temperature to simulate downhole conditions. The MACS analyzer machine is an advanced form for pressurized consistometer. A low friction magnetic drive rotates the stirrer through magnetic forces created between magnets attached to the stirrer and the motor, and the viscosity is monitored similar to that of a regular pressurized consistometer. When the conditioning time has elapsed, the motor is shutoff, and a pulley system is introduced between the magnetic drive and a variable speed stepping motor, through a load cell which records the force required to rotate the stirrer (magnetic drive) at very low speeds (0.5 – 2.0°/min). It is this setup (Gel Strength mode) of the MACS analyzer machine that monitors the SGS of the cement (see Fig. 10). [3, 13, 14]

Gas Flow Model Test

This test was done externally by Baker Hughes' lab facilities in Aberdeen. The following description and procedure is provided by the company. [15, 16]

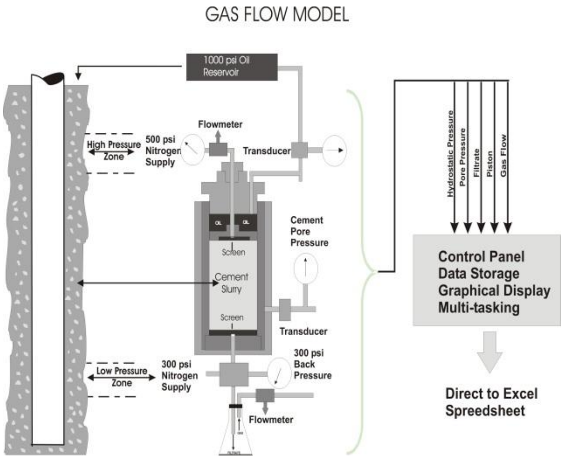


Figure 11: Diagram of the Gas Flow Model test cell. (Baker Hughes)

For testing a slurry's resistance to internal gas flow during setting, a gas flow test model is utilized. An operational diagram of the actual test cell is illustrated in Fig. 11. The test apparatus simulates real time conditions; a cemented annular space between a pressurized gas sandstone and a low pressure permeable zone, at bottom hole temperature. The apparatus is a 3" outer diameter by 10" long steel cylinder. Inside the cylinder a traveling piston is fitted and pushed down on the cement slurry to simulate the hydrostatic pressure, normally as a result of the fluid columns in the well (cement/drilling fluids/seawater). The piston is pushed down by hydraulic power (oil pressure). In the middle of the piston contains a small port covered by a 325/60 mesh stainless steel screen. The backside of the port is connected to pressurized nitrogen gas, through the top assembly, which simulates the high pressure and high permeability gas zone. The bottom assembly has also a center port covered by the same type of stainless screen. Once again, nitrogen gas is utilized via this port and screen. A pressure regulator is utilized to hold a constant pressure to simulate a lower pressure, high-permeability formation. The performance of the regulator is similar to a check valve. If the pressure on the test cell side of the regulator is greater than the set value, then the regulator allows fluids (either cement filtrate or Nitrogen gas) to leak off. Any filtrate is collected in the glass connected to the bottom regulator, and any gas flow is detected by the flowmeter also connected to the glass collector.

The gas flow test model actually records in real time (automatically, via microprocessors/ software) all pressures, the volume of any cement filtrate and/or whole gas that passes through the cement. Additional pressure monitoring ports in the cell allow for the recording of the actual pore pressure of the cement slurry as it cures. This particular pressure reading is critical during the test, as a gas tight slurry will typically show a gradual decline of the slurry pore pressure as the slurry sets and no longer transmits the simulated hydrostatic pressure of the fluid above the cement top. However, in instances where gas is actually working through the slurry matrix, the slurry pore pressure will typically cease its decline over time and begin to rise again, as high-pressure formation gas forces its way into the setting cement slurry matrix. At the same time, data recording will typically indicate excess slurry filtrate being forced from the setting slurry, and in some instances, whole gas will be detected flowing through the slurry and out of the test cell.

The cement slurry is prepared as described and placed in an atmospheric consistometer, heating it from room temperature to BHCT and conditioned for one hour. The slurry is then poured into the test cell and placed into a jacket that is preheated to the applicable BHST. A pressure of 400 psi is applied to the back regulator (low pressure zone), 1000 psi to the traveling piston (hydrostatic pressure) and 600 psi to the tubing through the piston to the cement (high pressure zone).

In order for a slurry to be considered gas tight in a test with the model, no additional filtrate or gas volume should increase when the pore pressure in the cement drops below the high pressure zone (600 psi).

The Results

Additional graphs/plots from tests that have been mentioned in the text can be found in the amendment. Also, necessary calculations and slurry recipes can be found in the amendment.

Rheology

Table 2: Rheology test result for 1.65sg lead cement.

1.65sg Lead Rheology Test				
Start temp (°C):	24.7	End temp. (°C)	24.3	
Rotational speed (rpm)	Ramp-up reading (degrees)	Ramp-down reading (degrees)	Reading ratio	Average Reading (degrees)
3	4.5	5.5	0.818	5
6	7	6	1.167	6.5
30	16	15	1.067	15.5
60	24	22	1.091	23
100	32	30	1.067	31
200	48	48	1.000	48
300	64	63	1.016	63.5
Gel 10s	3.5			
Gel 10min	12			

Table 3: Rheology test result for 1.80sg lead cement.

1.80sg Lead Rheology Test				
Start temp (°C):	22.3	End temp. (°C):	22.7	
Rotational speed (rpm)	Ramp-up reading (degrees)	Ramp-down reading (degrees)	Reading ratio	Average Reading (degrees)
3	7.5	9.5	0.789	8.5
6	12	11	1.091	11.5
30	32	30.5	1.049	31.3
60	51	48	1.063	49.5
100	70	67	1.045	68.5
200	110	110	1.000	110.0
300	146	147	0.993	146.5
Gel 10s	5			
Gel 10min	22			

The rheological tests of the lead and tail slurry shows that there are no issues of neither settling nor excessive gelling, since the reading ratios are close to one (1.0) as seen in table 2 and 3. In other words the cement slurries are stable. The only exception is that there appears to be some gelling (<1.0) occurring at low rotational speeds. However, repeatability of data taken at rotational speed of 3 rpms, or lower, is often poor and may be omitted from the test (except the 10s/10min measurements) [11].

Thickening Time

1.65sg Lead Slurry

The lead cement slurry recipe that was provided by Baker Hughes was designed to have a thickening time between 8-9 hours, which is defined as the time it takes the slurry to reach a viscosity of 30Bc. Viscosity above 30Bc is considered unpumpable. It was quickly determined that the slurry contained too much retarder (1.0 liter per hundred kilos (LHK)), and even when reducing the retarder to half of the amount (0.5 LHK), it still was having an excessive thickening time. As seen on Fig. 12 it took 16.7 hours for the lead to reach 30Bc. When the retarder was further reduced to 0.25 LHK the slurry (#4) finally achieved the designed thickening time as the results varied from 8.8 hours (Fig. 13) to 9.4 hours, which is acceptable. It is important to note that these initial tests of the lead slurry were performed using the incorrect test pressure

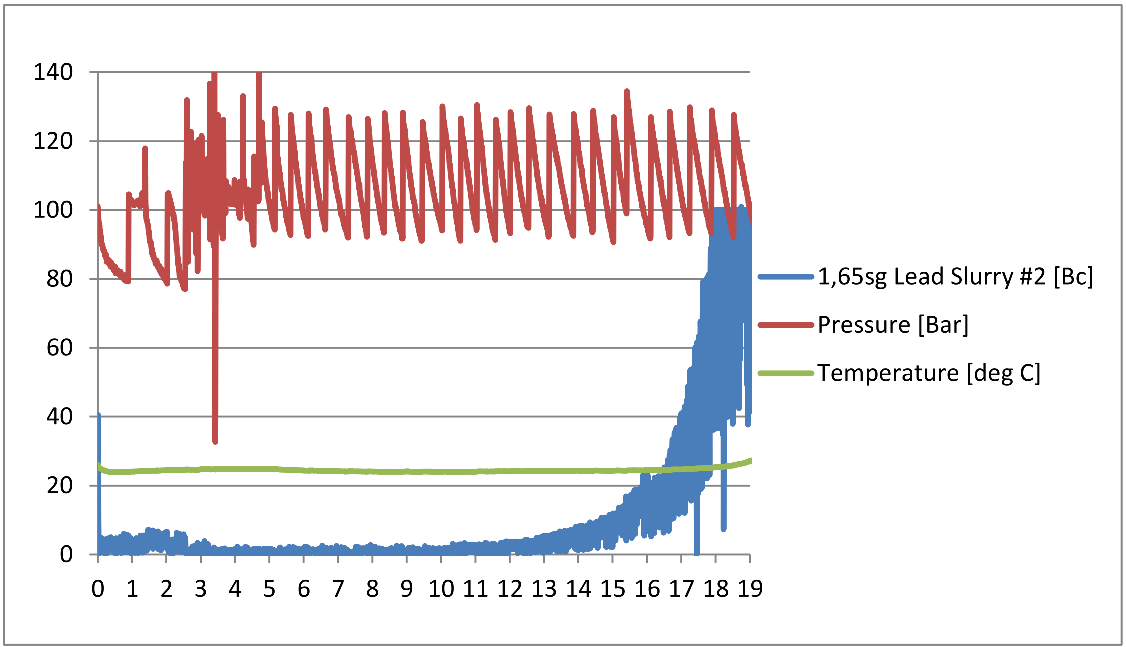


Figure 12: Test result of the 1.65sg lead slurry with too much retarder (0.5 LHK). The slurry was tested with 100 bars and 24°C. (E.S. Keeling)

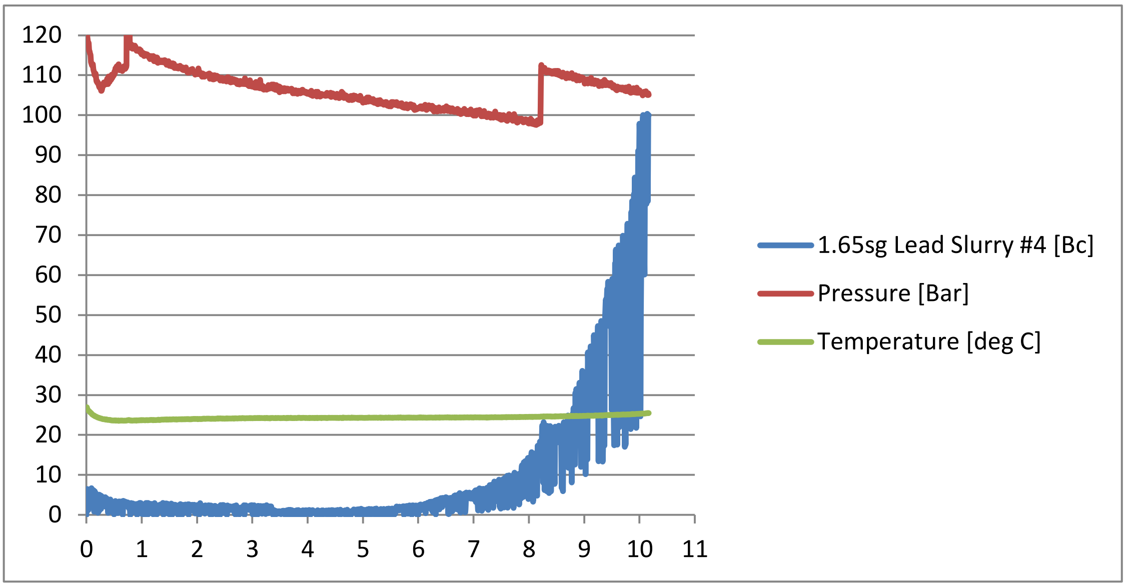


Figure 13: Test result for the 1.65sg lead slurry with correct amount of retarder (0.25 LHK). Tested with 100 bars and 24°C. (E.S. Keeling)

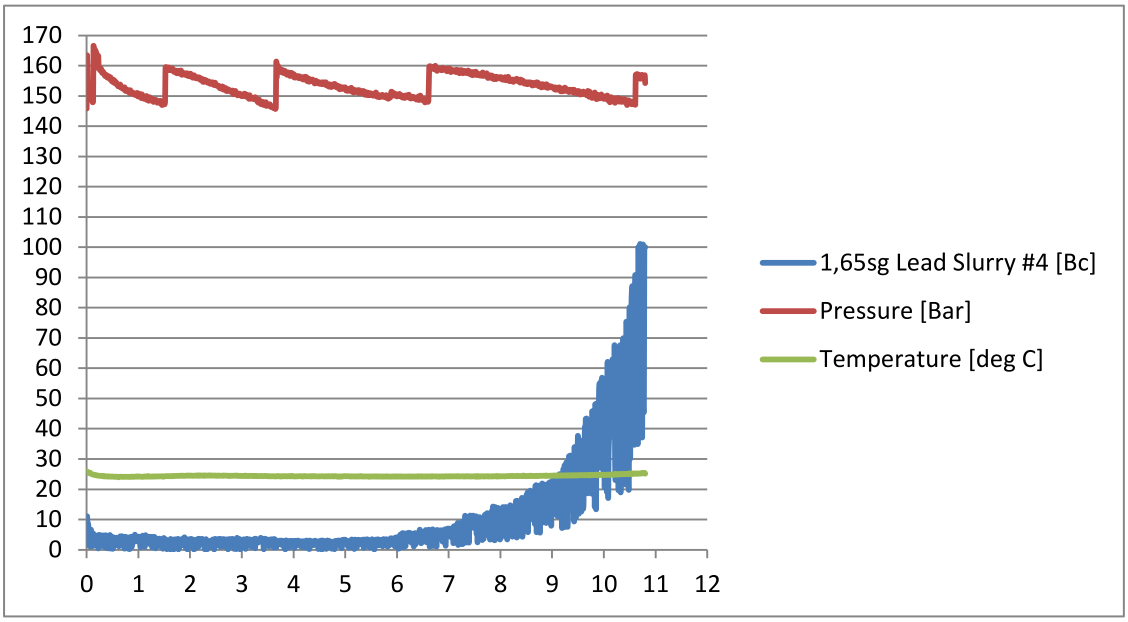


Figure 14: Test result of the 1.65sg lead slurry recipe #4. Tested with 150 bars and 24°C. (E.S. Keeling)

close to 100 bars. However, as is shown further down, a change in pressure had little effect on the results. The "thick" lines of the viscosity (blue) in plots are caused by noise, and it is the upper limit that is considered to be the actual value.

Two tests were performed on the lead slurry using the correct pressure above 150 bars, which shows (Fig. 14) that the viscosity profile is very similar to the 100bar tests. The two tests of lead slurry at 150 bars achieved a thickening time (30Bc) of 9.3 and 9.4 hours. The graph also reveals that the slurry does not have a right set angle (RAS) behavior as it took both tests over 1 hour to reach 100Bc from 30Bc. On the other hand, the slurry maintains a constant low viscosity until the designed thickening time is approached. This is beneficial as the lead keeps hydraulic pressure on the tail slurry as it sets up.

1.80sg Tail Slurry

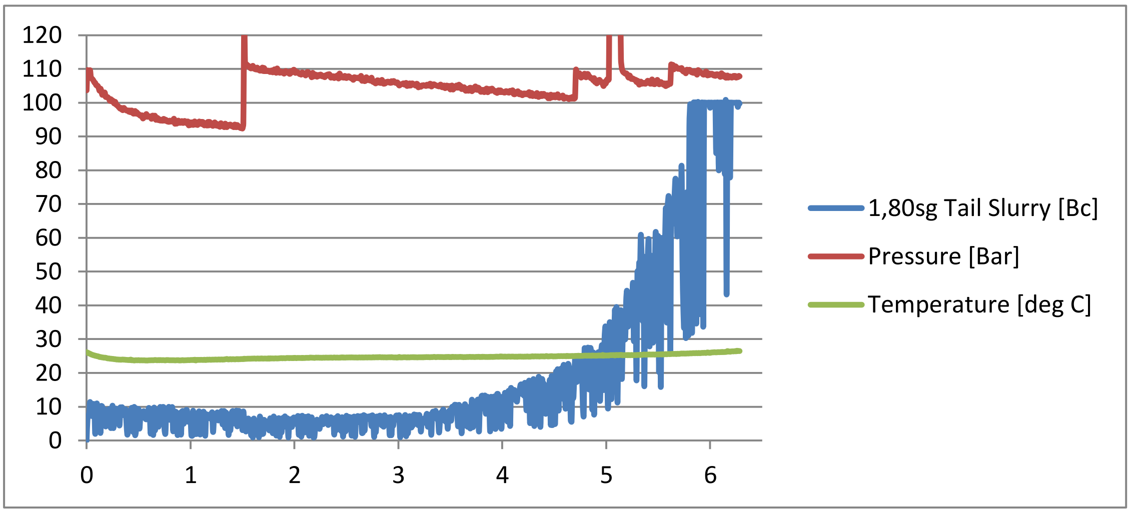


Figure 15: Test result of the 1.80sg tail slurry prior to the pressurized consistometer. Tested with 100 bars and 24°C. (E.S. Keeling)

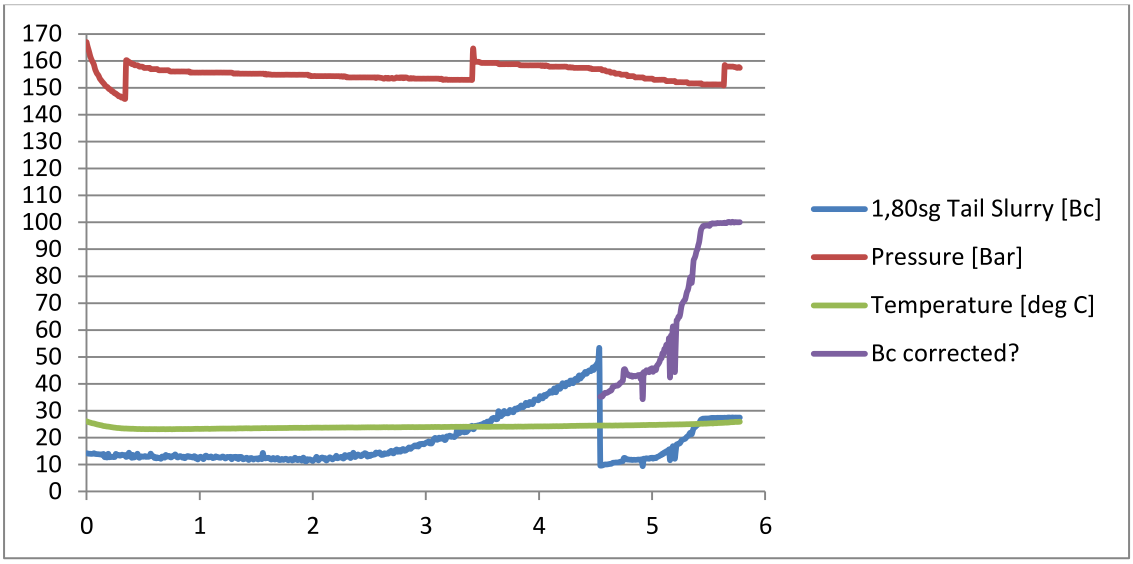


Figure 16: Test result of the 1.80sg tail slurry. Tested with 150 bars and 24°C. The purple line is an attempted correction of the viscosity when the pressurized consistometer failed. (E.S. Keeling)

As for the lead, the first tests of the tail cement were performed using incorrect pressure of 100 bars (see Fig. 15). This proved to be valuable as the tests using excess of 150 bars, the equipment kept failing, but the trend of what the failed tests (Fig. 16 and 17) show, that the thickening time and the viscosity profile are quite similar. The tail cement slurry was expected to gain 30Bc within 4.5 – 5.5 hours, which the tests confirm. Actually the test in Fig. 16, the tail reaches 30Bc in 3.8 hours, but this is still acceptable with respect to pumping time. In Fig. 16 one can also notice that the noise on the viscosity monitoring has been fixed. However, on the same test the input voltage to the viscometer dropped (failed), creating an incorrect viscosity reading when the tail slurry almost reached 50Bc at 4.5 hours. The purple line on the same plot is an attempt to multiply the faulty output values with a correction factor, but by doing that the viscosity value drops below the value when failing, starting at ≈35Bc. However, the purple line reaches 100Bc at the roughly same time as the other plots (Fig. 15 and 17). The viscosity plot on Fig. 17 has an irregular shape from start until about 3 hours of running. This is not a result of the slurry's viscosity. It is believed to be a consequence of friction being created between the pressure membrane (black rubber bit seen on Fig. 18) and the cell stirrer. What happens is that the brass on center of the pressure membrane is chafing on the stirrer, causing the viscosity output to give falsely high viscosity readings. As the friction surfaces are chafed away, the friction reduces

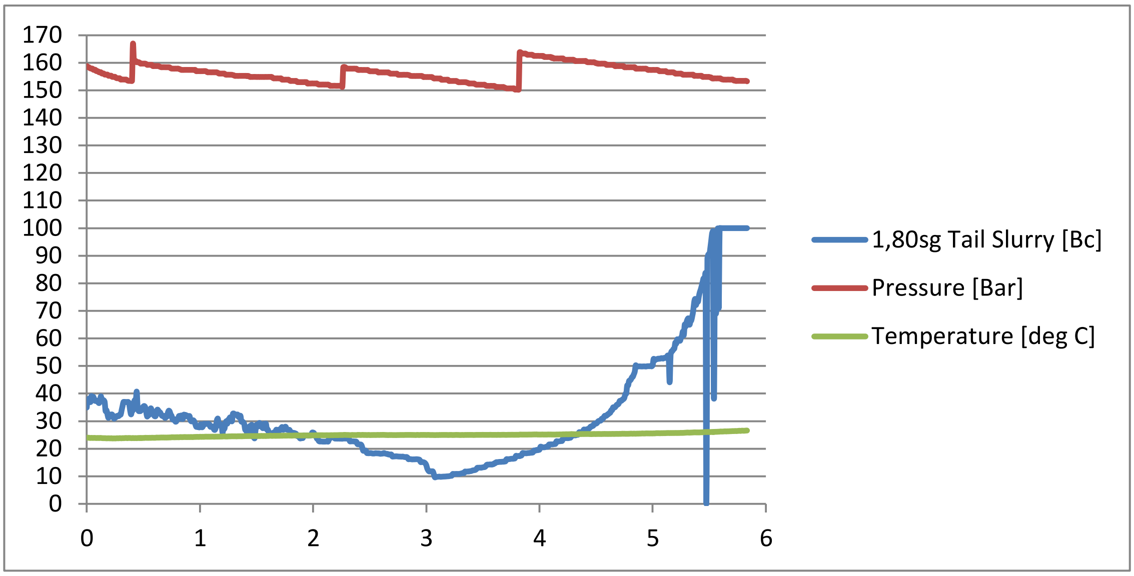


Figure 17: Test results of the 1.80sg tail slurry. Tested with 150 bars and 24 °C. The wobbly line prior to 3 hours running time is due to friction between components inside test cell. (E.S.Keeling)

Figure 18: The components of the cell placed inside the pressurized consistometer. (E.S. Keeling)

and the viscosity output reduces accordingly. On Fig. 17 one can see the viscosity reaches the normal value (the slurry's actual viscosity) just before the slurry's viscosity actually begins to increase just after 3 hours of running. The tests performed at 150 bars shows that the viscosity is leveling off a bit at ±50Bc. This is probably because of the cement in the small area between the stirrer and the cell inner wall "slips" at the cement-inner wall interface.

Despite the problems with the pressurized consistometer when testing the tail cement the plots together show that the slurry keeps a low constant rheology until the expected thickening time is approached. Similar to the lead, the tail cement slurry doesn't possess RAS properties as it takes more than 1 hour to reach 100Bc from 30Bc, and not in matter of minutes. The lack of RAS behavior, both in lead and tail cement, is probably due to the large amount of silica contained in the slurries. This might be because the chemical reaction with the silica is slower than cement, and/or the large amount of the silica volume is "in the way" for the cement hydration process slowing the chemical reaction down.

All of the tests show that the tail slurry reaches 100Bc close to 6 hours running time or less. This is a very good timing as tests of the lead reveals that it starts to set around the same, or just after the same time. In other words it seems like the lead exerts full hydraulic pressure until the tail reaches 100Bc (≈325 lbf/100ft^2, ref. Fig. 4).

Please note that all the thickening tests were programmed to test at a constant 24°C (BHCT), but because of the increased friction because of the increased viscosity of the cement, the cell temperature creeps above 25°C near the tests end. Also, the test pressures (red line in figures) used (100 and 150 bars) were supposed to be constant, but because there seem to be some pressure bleeding due to leakage in the machine somewhere, pressure

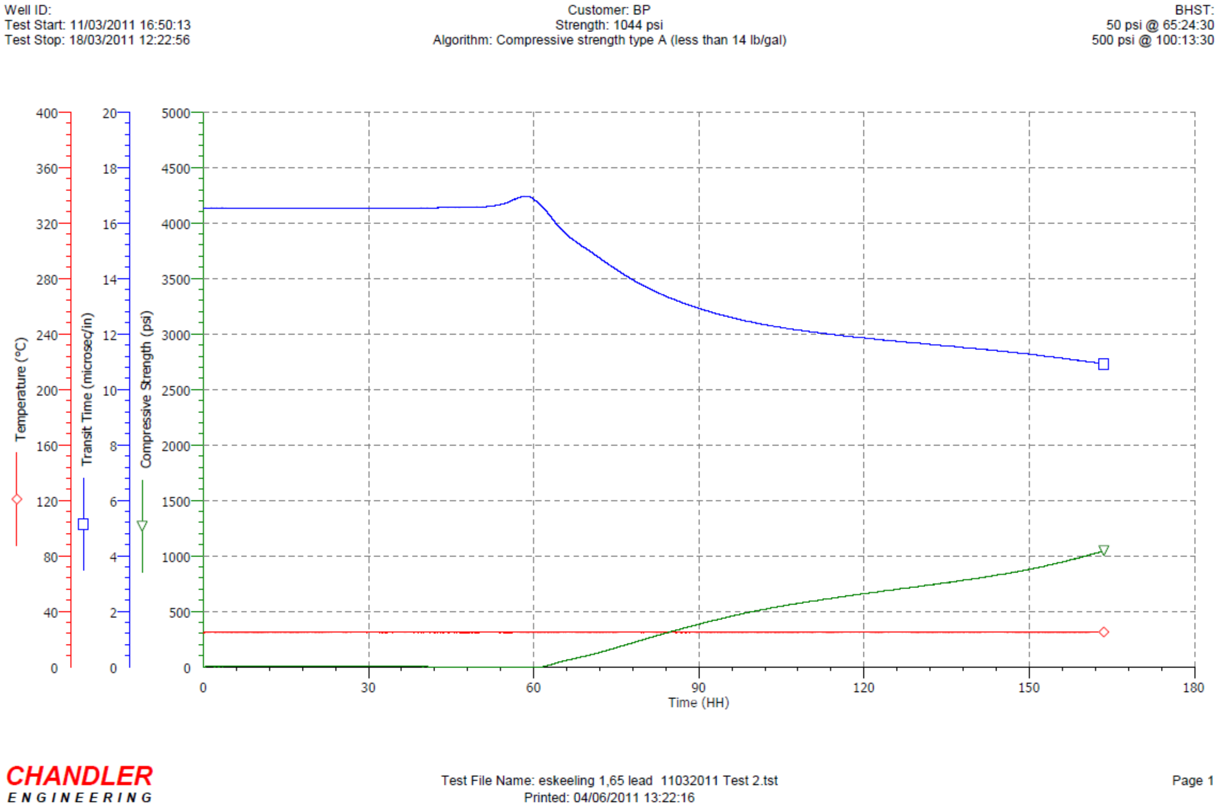


Figure 19: Compressive strength (green line) development of the initial 1.65sg lead slurry with too much retarder. Temperature (red line) and ultrasonic transit time (blue line) is also shown. (E.S. Keeling)

had to be applied during the tests, giving it the zig zag'y look.

Compressional Strength (UCA)

To examine the compressive strength development, the pressures and static temperatures used corresponds to the base case at depths of 900m and 1070m TVD MSL. This means that the lead cement has been tested with a constant pressure of 122 bars and a static temperature of 27°C, simulating conditions at 900m TVD MSL. The tail cement has been tested for conditions at 900m TVD MSL <u>and</u> 1070m TVD MSL. This means the tail has been tested with 122bars/27.1°C and 152bars/34.6°C. This is done to see the differences in strength development between the bottom and the top of the tail cement since it is assumed to cover the troubled SWF area. This is also to see the differences in compressive strength development between the lead and tail cement at the same depth.

The key property is how fast after the initial set (100Bc) the cement starts to build compressive strength (when the cement starts to become a solid). For lead cement the average time to 100Bc was 10 hours, while it was approx. 6 hours. Additional targets to reach is taken from the last revision of the cementing basis of design for the Skarv field [17] being issued at BP these days. These targets are for:

- <u>Lead compressive strength:</u>
  - >200 psi within 24hrs after placement, and
  - >500 psi within 7 days
- <u>Tail compressive strength:</u>
  - >500 psi within 16hrs after placement

<u>1.65sg Lead slurry</u>

Seen on the Fig. 19 is a test of the initial lead cement slurry recipe that contained too much retarder (1.0 LHK). The plot shows that this slurry didn't start to build compressive strength until after 60 hours had passed. This was of course way too much. This initial test was performed with 100bars and a constant temperature of 24°C since the programmable heat/cooling bath wasn't available until a later date. As explained earlier the slurry with the right amount of retarder was 0.25 LHK which was used to test with base case parameters.

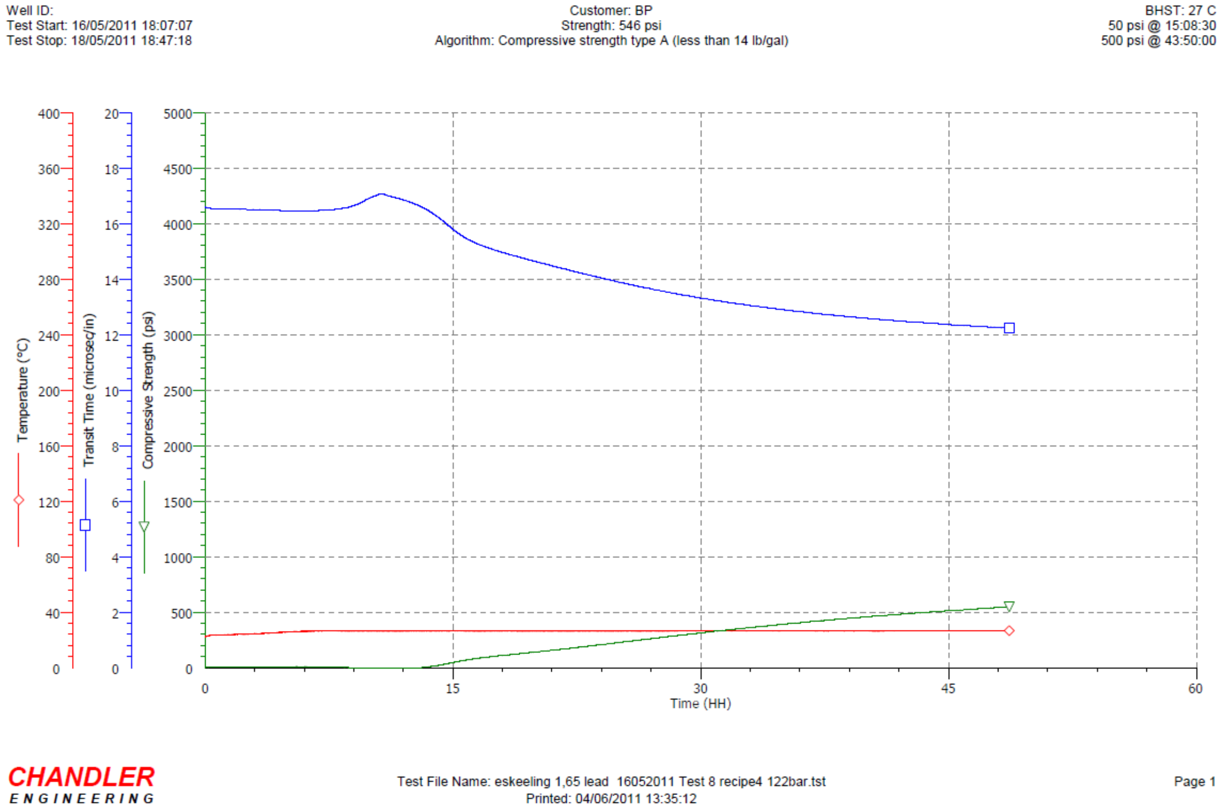


Figure 20: Compressive strength (green line) development of the 1.65sg lead slurry at downhole conditions (122bars/ 27°C) at 900m TVD MSL. Temperature (red line) and ultrasonic transit time (blue line) is also shown. (E.S. Keeling)

Figure 20 shows one of two tests performed on the lead slurry with 122bars/27°C. The green line representing the compressive strength shows that it starts to build compressive strength after 13hrs and 8min. This is only roughly three hours after the lead slurry achieved 100Bc in the TT tests. In other words, it took only 3hrs to achieve a corresponding static gel strength of 14,400 lbf/100ft^2 from 325 lbf/100ft^2 (ref. fig.4). Remember 500 lbf/100ft^2 were considered to be resistant to fluid invasion. After 24hrs it achieved 207 psi, and 500 psi was achieved after only 43hrs 50min, well within the target of 7days. The second lead cement test (not shown) achieved 200 psi after 24hrs 23min, which is a bit over the 24hr target, but acceptable. 500 psi was achieved after 46hrs 50min, well within target. The same test showed the lead cement to start building compressive strength after 13hrs 21min, slightly more than the aforementioned test.

1.80sg Tail Slurry

The first test of the tail slurry was tested with the same parameters as the lead cement (122bars/27°C), which simulates the conditions at the top of the tail cement (see Fig. 21). The test shows that the top tail cement starts to build strength after only 7hrs 38 min. That is only roughly 1hr 38min after the average 100Bc thickening time of 6 hours. After 16hrs the cement has achieved 346 psi, not reaching the target of 500 psi. It is important to note that this is the compressive strength at top of cement. Still the tail cement has reached a strength of 232 psi when the lead starts to build strength after approx. 13hrs.

Two tests of the tail were performed at bottom hole conditions. The first test (not shown) was performed with 152bars/32°C. This deviates from the BHST prognosis of 34.6°C. Because of the external heat/cooling bath (Julabo) it is difficult to predict the heat loss of the heating fluid during transfer to the UCA cell. However, the formation temperature prognosis has an uncertainty of 4°C, and therefore the test is considered valid. This first tail test started to build compressive strength at 6hrs 36min, only roughly 36min after the 100Bc thickening time.

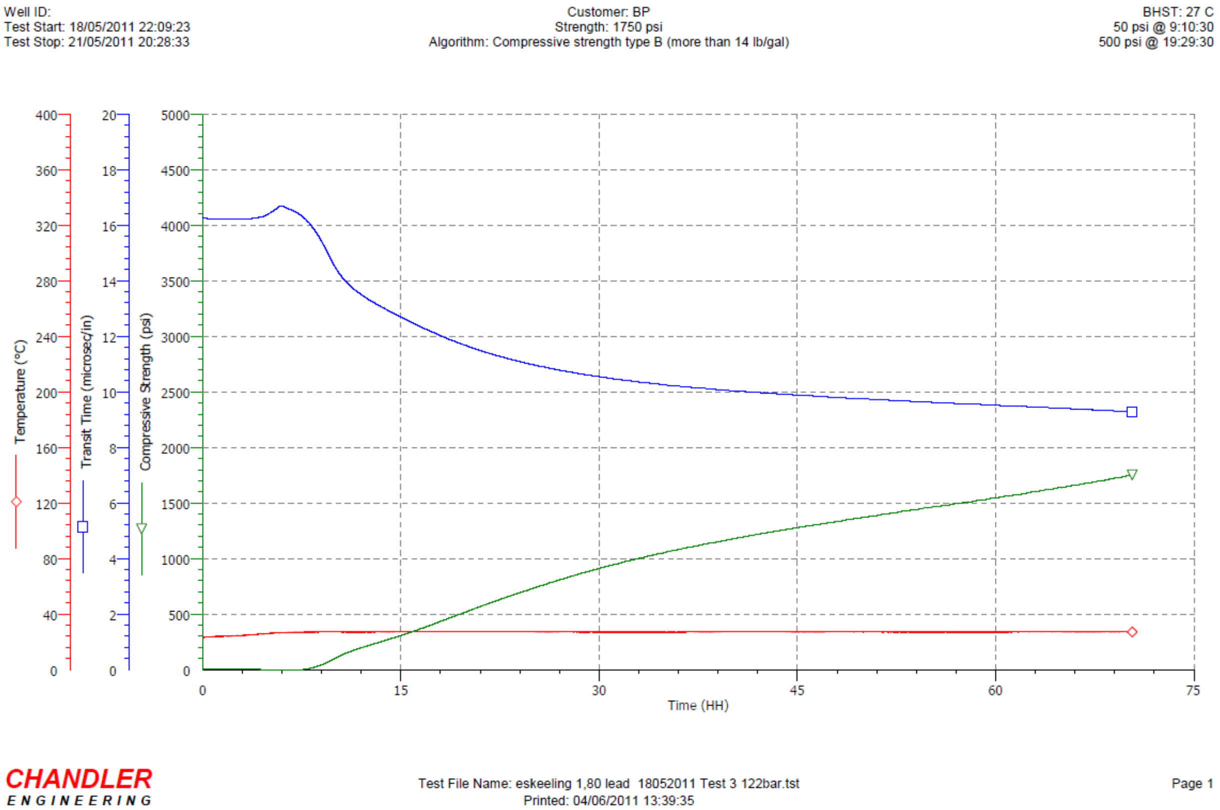


Figure 21: Compressive strength (green line) development of the 1.80sg tail slurry at downhole conditions (122bars/ 27°C) at 900m TVD MSL. Temperature (red line) and ultrasonic transit time (blue line) is also shown. The tail cement achieved 500 psi after 19hrs 29min. (E.S. Keeling)

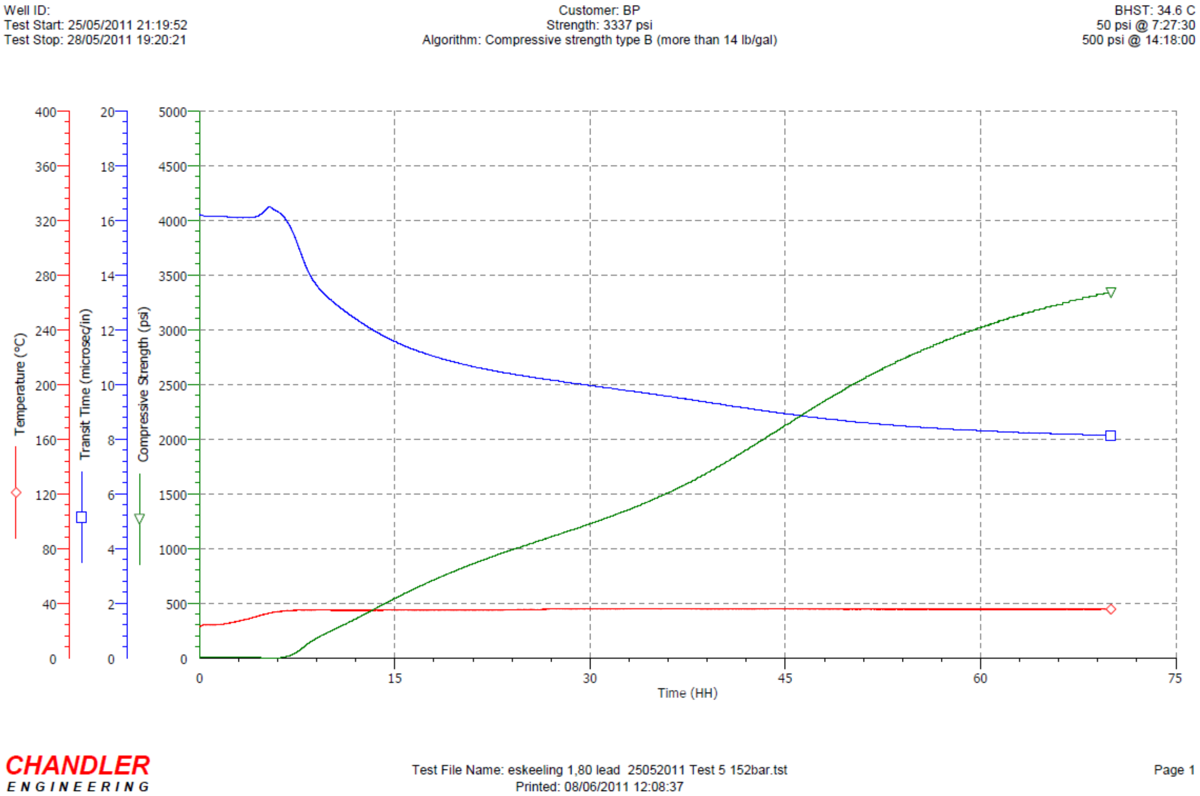


Figure 22: Compressive strength (green line) development of the 1.80sg tail slurry at downhole conditions (152bars/ 36.4°C) at 1070m TVD MSL. Temperature (red line) and ultrasonic transit time (blue line) is also shown. (E.S. Keeling)

A compressive strength of 500 psi was achieved at 15hrs 21min, which is within the target of 16hrs. The second tail cement test at simulated bottom hole conditions was performed with 152bars/35°C, and can be seen on Fig. 22. The tail starts to achieve compressive strength after 6hrs 18min, which is even closer to the 100Bc TT, than the aforementioned tail test. 500 psi was achieved at 14hrs 18min, which is also within target.

Static Gel Strength Testing

These were tests that were performed externally by Baker Hughes' facilities in Tomball, USA. To measure the transition time of the cement, the overpressure (Δp_{ob}) in the well at the applicable depth must be determined. The depth chosen is at 900m TVD MSL, the point where the transition between lead and tail cement is assumed to be. The overpressure at that point is calculated ($\Delta p_{ob} = p_{lead} - p_{SWF}$) to be 22.8 bars = 331psi (ref. Fig. 1). By using equation (3), the CGS becomes 305 lbf/100ft^2. Both the old and new definitions (ZGS - 500 lbf/100ft^2 **vs** CGS - 500 lbf/100ft2) of the transition time has been measured when the SGS tests were performed on the lead and tail slurry.

Because the requested input parameters were not obeyed, the pressures and temperatures used during the SGS tests deviates slightly from the base case (at 900m TVD MSL). Instead of using 122 bars and a static temperature of 27°C, a pressure of 138 bars (2000psi) has been used, together with a static temperature of 28°C (82.4°F) for lead slurry and 33°C (91.4°F) for tail slurry. Also the circulation temperature is not the same for lead and tail. Circulation temperature used for

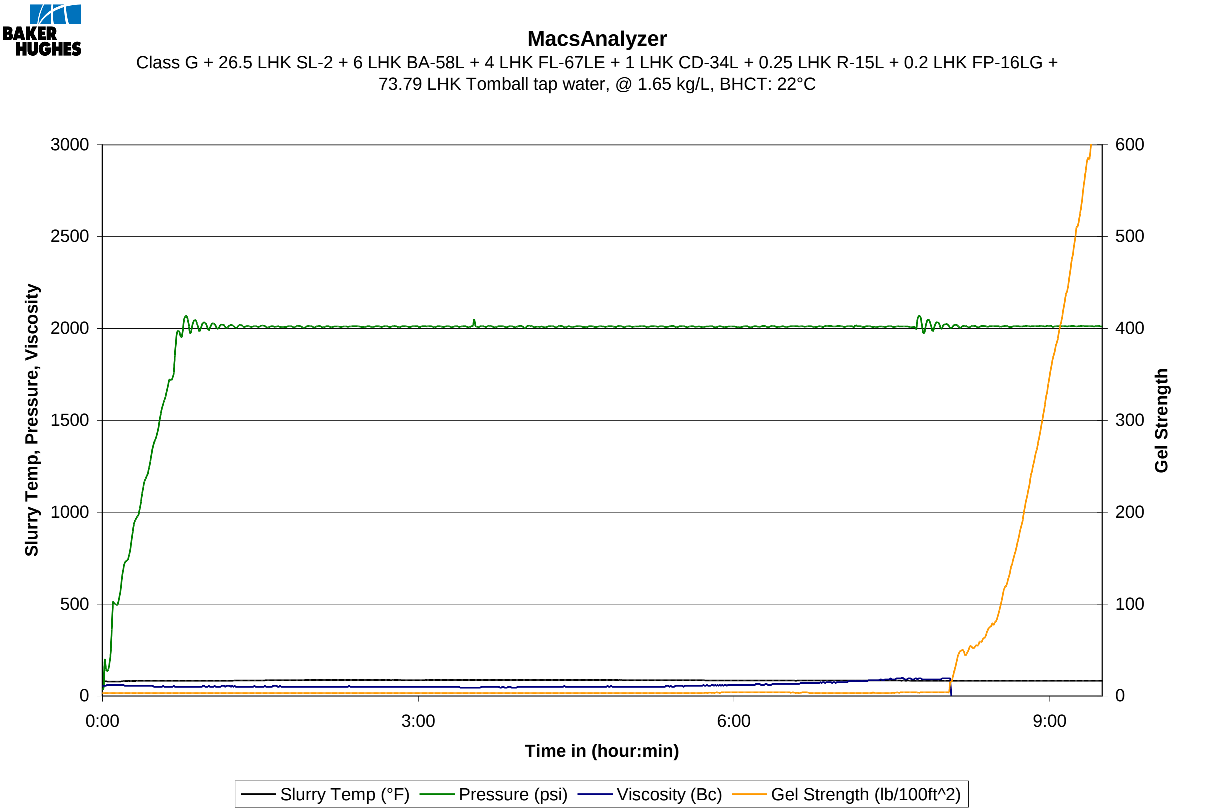
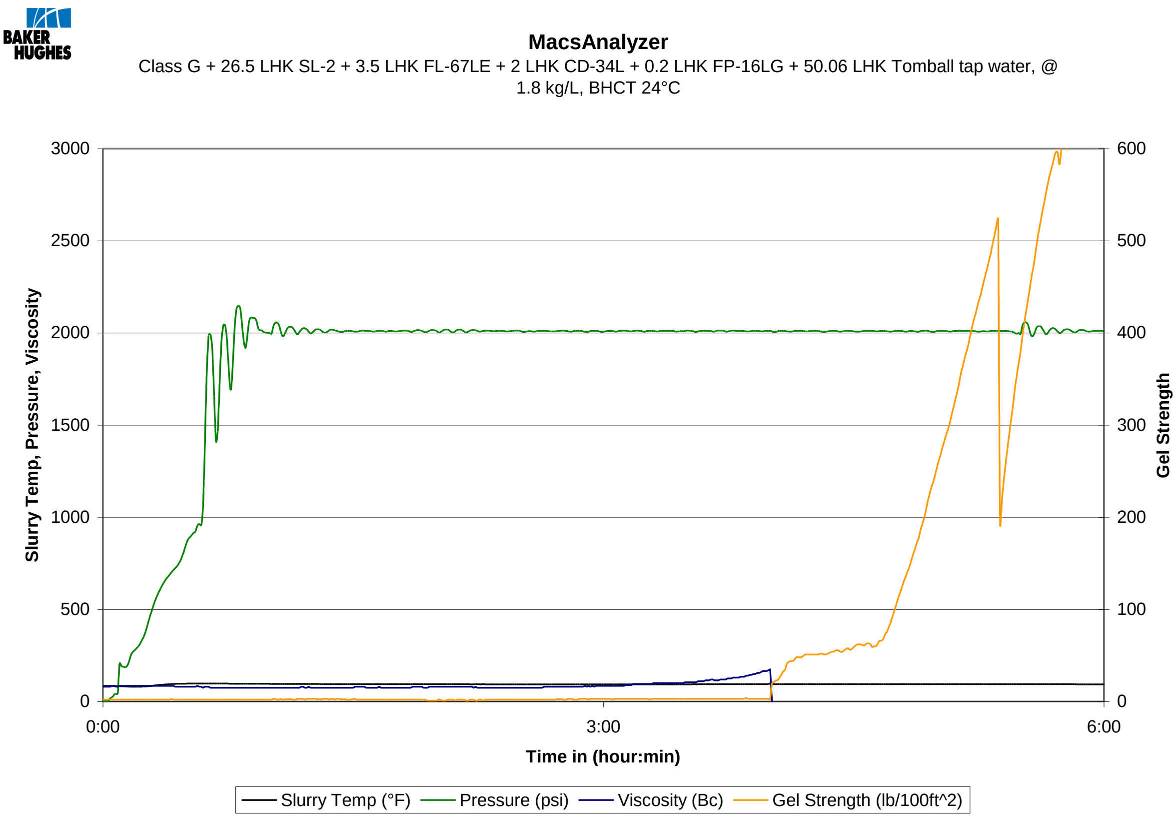


Figure 23: Plot over the SGS development during the test of the lead slurry. [13]

Table 1: Overview over ramp-up time and conditioning time. Results of the transition times achieved by the lead. [13]

MACS Analyzer							
Thickening Time		Conditioning Time	Gel Strength lb/100 ft²				
ramp hr:min	pressure psi	hr:min	100 hr:min	CGS* hr:min	500 hr:min	500-100 hr:min	500-CGS hr:min
00:44	0, 2000	08:13	08:33	08:57	09:15	00:42	00:18

*CGS calculated at 305 lb/100ft²



Figur 24: Plot over the SGS development during the test of the tail slurry. [13]

Table 2: Overview over ramp-up time and conditioning time. Results of the transition times achieved by the tail. [13]

MACS Analyzer							
Thickening Time		Conditioning Time	Gel Strength lb/100 ft²				
ramp hr:min	pressure psi	hr:min	100 hr:min	CGS* hr:min	500 hr:min	500-100 hr:min	500-CGS hr:min
00:44	0, 2000	04:00	04:45	05:05	05:21	00:36	00:16

*CGS calculated at 305 lb/100ft²

lead/tail was 22°C/24°C (71.6°F/75.2°F) respectively. The deviation in test pressure is probably not a problem as it is the change of the slurries gel strength itself that is the critical parameter of the test result, which has already been established to be 305 lbf/100ft^2. However, the "high" static temperature of 33°C used during the SGS testing of the tail slurry may have distorted the transition time results somewhat. Also note that local tap water is used in the slurry instead of distilled water. [13]

The result is considered positive when the transition time is less than 45 min, but preferable less than 30 min.

<u>1.65sg Lead Slurry</u>
Figure 23 shows the development of the lead slurry's static gel strength development (yellow line), viscosity during conditioning (blue line), slurry temperature (black line) and the pressure in the cell (green line). Table 2 shows the critical numbers extracted from figure 23. The test shows that the thickening time of 8hrs 33min to 100 lbf/100ft^2 (= 30Bc) is similar to what the thickening time tests performed in the pressurized consistometer. Further, it takes another 24 minutes (8hrs 57min) to reach the calculated critical gel strength, the point where the hydrostatic pressure in the well exerted by the cement is equal to the assumed pore pressure of the SWF zone. This is also the starting point for when the cement is vulnerable to fluid invasion/migration. The test result is very positive as it shows the cement has a transition time of only 18 minutes, which is well below the 45min target, but also below 30 minutes. The old definition of the transition time (500 –

100 lbf/100ft^2) also gets an acceptable result of 42 min. [13]

1.80sg Tail Slurry

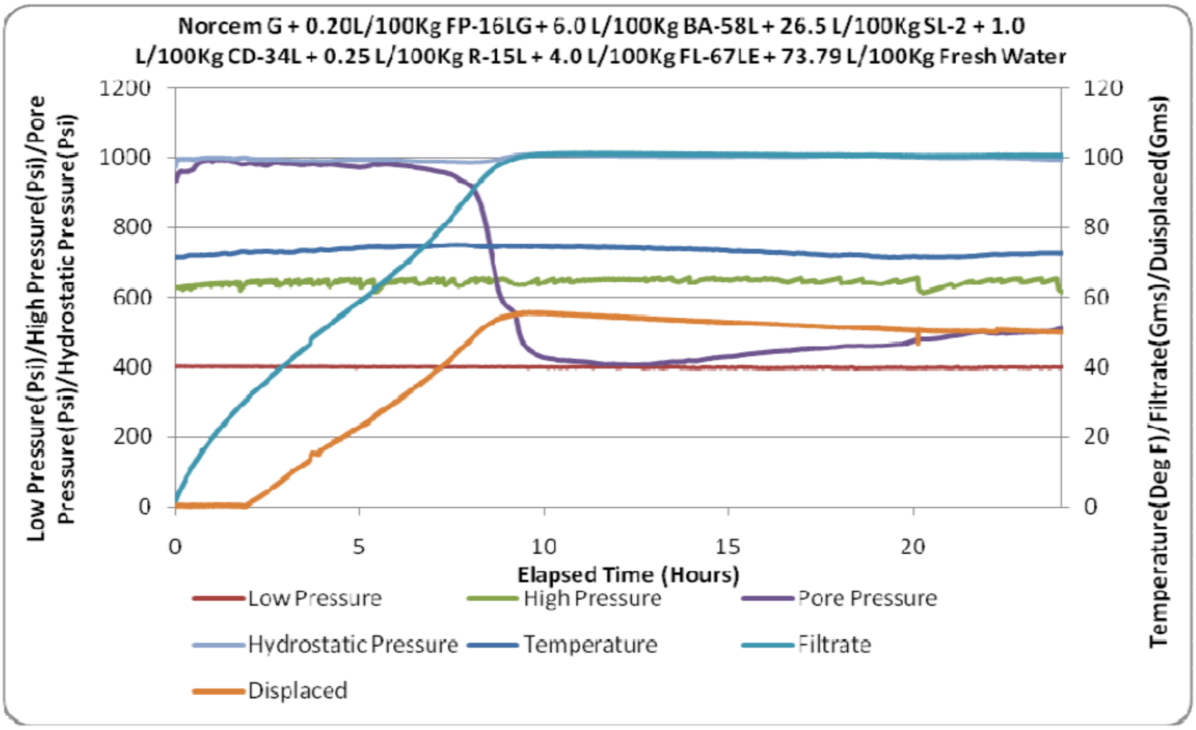
Figure 24 and Table 3 shows the results of the tail slurry's performance in the SGS test. Also the tail achieves 30Bc (100 lbf/100ft^2) in the same timeframe as designed and proved in the thickening time tests performed in the pressurized consistometer. The tail reaches the critical gel strength after 5hrs 5mins, the point of well underbalance. It is important to note that the CGS for the tail cement at the bottom (1070m TVD MSL) will be higher as the pressure overbalance is higher. In other words the CGS will be closer (calculated to be 342 lbf/100ft^2) to the 500 lbf/100ft^2 value that is considered fluid invasion resistant, with the result of the transition time will be shorter. The transition time achieved in the test is a very positive 16 minutes, well below target. Also the old transition time definition (500 – 100 lbf/100ft^2) is close to the 30 min target with the achieved 36 minutes. As noted, the test of the tail was conducted with the BHST of 33°C, instead of the instructed 27°C. This may have caused the tail to achieve a shorter transition time than actual at that depth (900m TVD MSL), but it is unlikely that the transition time would have increased above the 30min (especially 45min) target if the correct static temperature had been used. In any case the tail slurry achieves 500 lbf/100ft^2 several hours before the hydrostatic pressure, exerted by the lead, is decreased significantly. [13]

The significant oscillation of the SGS curve at the end of the test is due to the bond between the cement and inner cell wall has slipped, causing the sharp reduction in gel strength. Luckily the cement had reach 500 lbf/100ft^2 before the slippage and has no influence on the transition time results.

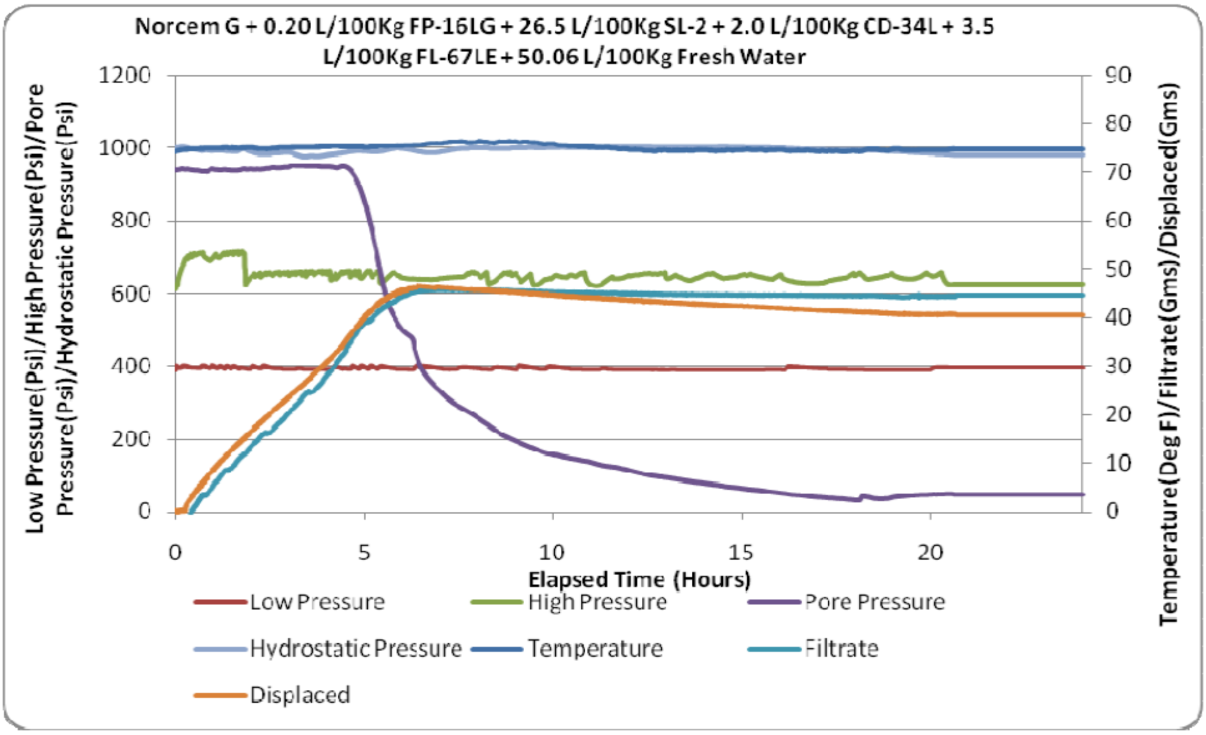
Gas Flow Model Test

1.65sg Lead Slurry

The test was performed while using a BHCT of 22°C (71.6°F) and a BHST of 28°C (82.4°F). The test results (Fig. 25) shows the pore pressure (purple line) starts to decline after 8 hours indicating the cement starts to set. This coincides with results in both thickening time tests and static gels strength tests. As the pore pressure in the cement drops below the simulated high pressure gas zone (green line) of 600psi, the accumulation of filtrate (turquoise line) levels off, reaching a value of 100g. The displaced water volume (brown line) also levels off, indicating that no gas intrusion is evident. A gas intrusion would be indicated if the displaced water volume had increased to maximum value. The setup for



Figur 25: Test result for the Gas Flow Model test of the lead slurry. [15]

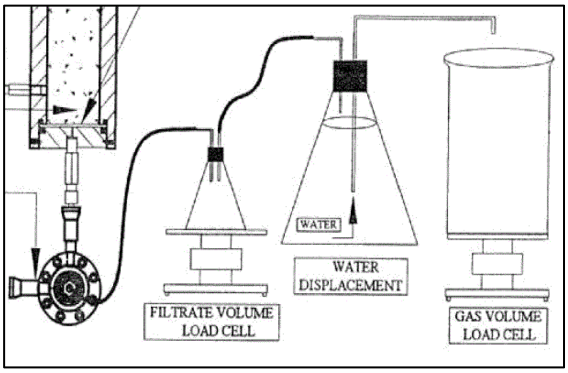


Figur 26: Test result for the Gas Flow Model test of the tail slurry. [15]

recording the filtrate volume and displaced (Fig. 27) shows that the two volumes should be recorded to be the same. Any filtrate entering the filtrate volume load cell displaces air into the water displacement, which in turn displaces the water to the final cell. Perhaps the line from the backpressure regulator was not completely filled with fluid when the test started may be the reason why the filtrate and water displaced volumes are different [5]. The important thing is that the two volumes levels off at the same time. [15]

<u>1.80sg Tail Slurry</u>

The test was performed while using a BHCT of 24°C (75.2°F) and a BHST of 33°C (91.4°F). The test results (Fig. 26) shows the pore pressure (purple line) starts to decline after 5 hours indicating the cement starts to set. This coincides with results in both thickening time tests and static gels strength tests. As the pore pressure in the cement drops below the simulated high pressure gas zone (green line) of 600psi, the accumulation of filtrate (turquoise line) levels off, reaching a value of 45g. The displaced water volume (brown line) also levels off, at the same time, indicating that no gas intrusion is evident. [15]



Figur 27: The actual setup for recording filtrate volume and water displacement caused by gas flow. (Baker Hughes)

Other Observations and Results

Before the work of this Thesis was commenced, Baker Hughes had performed a fluid loss test which resulted in 44ml/30min (see amendment).

Excess volumes of slurries prepared for UCA testing was put in plastic cups to cure in room temperature and atmospheric pressure. No free fluid was observed from neither lead nor tail slurry.

There was observed some trapped air bubbles in that tail slurry after mixing. It was suspected that this could be the reason for the problems related to the testing of the tail slurry at 150 bars. In other words the chafing of the brass on the pressure membrane was caused by an excessive traveling of the membrane along the stirrer's axel when pressure compressed the air bubbles in the slurry. However, the problem prevailed after introducing the procedure of removing the air in the slurry in a vacuum machine prior to thickening testing. In the UCA testing no foaming was observed in the slurries after the 20 minute conditioning used in the preparation procedure. More foam preventer should probably be added to prevent in-field mixing problems.

Conclusions

The scope of this work was to investigate if the alternative cement program for the 18.7" casing in the 24" section was applicable for preventing annular fluid migration such as shallow water flow.

The designed cement slurries tested has proven to exhibit the properties that are recognized to prevent annular migration/invasion. These are:

- No free fluid
- Low fluid loss (44ml/30min)
- **Short transition time within 30 minutes (18 minutes for lead and 16 minutes for tail)**
- Low and constant viscosity until the cement is designed to start setting
- Gas flow Model Test indicates low permeability during transition from liquid to solid.
- **The lead cement slurry indicates to exhibit full hydrostatic pressure until the tail cement slurry reaches a static gel strength above 500 lbf/100ft^2, which is considered to be the value that is resistive against fluid invasion.**
- The cements start to build compressive strength relatively quickly after they have reached 500 lbf/100ft^2, especially the tail cement slurry.
- The tail cement starts to build compressive strength (<7hrs 38min) before the lead cement reaches the critical static gel strength (8hrs 57min).
- The cement slurries tested exhibit no RAS behavior, probably because of the high silica content (35%BWOC).
- Some foaming was observed.

It is clear that it is possible to prevent SWF issues using conventional G-class slurries that are designed to be resistant towards annular fluid migration. Also it has been shown that by designing the tail to set before the lead does ensures hydrostatic overbalance until the SWF zone covering tail slurry sets and thus effectively removing one of the root causes that must be satisfied for annular fluid migration to take place. It becomes an additional safety feature that helps the fluid migration resistive cements to perform even better. Compared to foam cementing, conventional cement slurries are an economic choice and there are fewer risks related, since the technology is simpler and there is less equipment involved in the cementing operation. It is also important to note that a foam cementing solution does not guarantee to solve the problem (foam cement jobs in the Skarv field has also been deemed unsuccessful).

If the conventional G-class cement solution is to be used for future developments, it would be an advantage to plan for using cement from the same batch for the entire campaign to ensure that the slurries perform consistent for all the wells involved.

Acknowledgement

The author would like to thank Per Skadsheim and all the people involved at Baker Hughes for all their support. The author also would like to thank Helge Hodne at the University of Stavanger for all help and guidance.

Nomenclature

API	= American Petroleum Institute
Bc	= Beardens units (viscosity)
BHCT	= bottom hole circulating temperature
BHST	= bottom hole static temperature
BML	= below mud line
BWOC	= by weight of cement
°C	= degrees Celsius
CGS	= critical gel strength

ECD	= equivalent circulation density
FPSO	= floating production storage and offloading unit
ft	= feet
KCL	= potassium chloride
lbf	= pound force
LHK	= liters per hundred kilos
m	= meter
MACS	= multiple analysis cement system
MSL	= mean sea level
psi	= pounds per square inch
P_{lead}	= hydrostatic pressure exerted by the column of lead cement and sea water
P_{Frac}	= estimated frature pressure at surface casing shoe
P_{SWF}	= pore pressure in shallow water flow zone
P_{Tail}	= hydrostatic pressure exerted by tail cement and fluids above
RAS	=right set angle
rpm	= revolutions per minute
sg	= specific gravity
SGS	= static gel strength
SWF	= shallow water flow
TD	= total depth
TT	= thickening time
TVD	= true vertical depth
UCA	= ultrasonic strength analyzer
ZGS	= zero gel strength

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Amendment

Table 4: Lead slurry recipes used during testing. The initial slurry recipe (#1) contained too much retarder. The recipe was tuned several times until the right amount was confirmed with recipe #4 containing 0.25 LHK retarder.

	1.65sg Lead Slurry #1		1.65sg Lead Slurry #2		1.65sg Lead Slurry #3		1.65sg Lead Slurry #4	
	Recipe	Labmix (600ml)	Recipe	Labmix (600ml)	Recipe	Labmix (600ml)	Recipe	Labmix (600ml)
Cement	100kg	130.18ml/ 419.17g	100kg	130.39ml/ 419.84g	100kg	130.60ml/ 420.52g	100kg	130.49ml/ 420.18g
Silica	26.50 LHK	111.08ml/ 198.83g	26.50 LHK	111.26/ 199.15g	26.50 LHK	111.44ml/ 199.47g	26.50 LHK	111.35ml/ 199.31g
Foam preventer	0.20 LHK	0.84ml/ 0.64g	0.20 LHK	0.84ml/ 0.64g	0.20 LHK	0.84ml/ 0.64g	0.20 LHK	0.84ml/ 0.64g
Microsilica	6.00 LHK	25.15ml/ 34.51g	6.00 LHK	25.19ml/ 34.56g	6.00 LHK	25.23ml/ 34.62g	6.00 LHK	25.21ml/ 34.59g
Dispersant	1.00 LHK	4.19ml/ 5.03g	1.00 LHK	4.20ml/ 5.04g	1.00 LHK	4.21ml/ 5.05g	1.00 LHK	4.20ml/ 5.04g
Retarder	1.00 LHK	4.19ml/ 5.44g	0.50 LHK	2.10ml/ 2.72g	0.00 LHK	0.00ml/ 0.00g	0.25 LHK	1.05ml/ 1.35g
Fluid loss agent	4.00 LHK	16.77ml/ 18.78g	4.00 LHK	16.78ml/ 18.81g	4.00 LHK	16.82ml/ 18.84g	4.00 LHK	16.81/ 18.82g
Distilled water	73.38 LHK	307.60ml/ 307.60g	73.66 LHK	309.23ml/ 309.23g	73.93 LHK	310.87ml/ 310.87g	73.79 LHK	310.50ml/ 310.50g

Table 5: Tail slurry recipe used during testing

	1.80sg Tail Slurry	
	Recipe	Labmix (600ml)
Cement	100kg	130.18ml/ 419.17g
Silica	26.50 LHK	111.08ml/ 198.83g
Foam preventer	0.20 LHK	0.84ml/ 0.64g
Dispersant	2.00 LHK	4.19ml/ 5.03g
Fluid loss agent	3.50 LHK	16.77ml/ 18.78g
Distilled water	50.06 LHK	265.06ml/ 265.06g

Table 6: Densities of cement and additives

Material:	Cement	Silica	Foam preventer	Microsilica	Dispersant	Retarder	Fluid loss	Distilled water
Density:	3.22sg	1.79sg	0.76sg	1.372sg	1.20sg	1.298sg	1.12sg	1.000sg

Pressure Calculations:

Thickening Time Testing

1.65sg Lead cement slurry:

$$P^{TT}_{lead} = (\,\rho_{SW} \times h_{SW} - \rho_{lead} \times (h_{TD} - h_{SW})) \times g$$

$$P^{TT}_{lead} = (1.03\text{sg} \times 374\text{m} + 1.65\text{sg} \times (1070\text{m} \; - \; 374\text{m})) \times 0.0981 = 150.4 \text{ bar}$$

1.80sg Tail cement slurry:

$$P^{TT}_{tail} = (\,\rho_{SW} \times h_{SW} - \rho_{lead} \times (h_{SWF} - h_{SW}) + \rho_{tail} \times L_{tail}) \times g$$

$$P^{TT}_{tail} = (1.03\text{sg} \times 374\text{m} + 1.65\text{sg} \times (900\text{m} \; - \; 374\text{m}) + 1.80\text{sg} \times 170\text{m}) \times 0.0981$$
$$= 152.9 \text{ bar} = 1.457 \text{ (ref. MSL)}$$

UCA Testing

1.65sg Lead cement slurry:

$$P^{UCA}_{lead} = (\,\rho_{SW} \times h_{SW} - \rho_{lead} \times (h_{SWF} - h_{SW})) \times g$$

$$P^{UCA}_{lead} = (1.03\text{sg} \times 374\text{m} + 1.65\text{sg} \times (900\text{m} \; - \; 374\text{m})) \times 0.0981 = 122.9 \text{ bar}$$

1.80sg Tail cement slurry:

$$P^{UCA}_{tail} = P^{TT}_{tail} = 152.9 \text{ bar}$$

Critical Gel Strength

Pore pressure at 900m TVD MSL:

$$P_{SWF} = \rho_{SWF} \times h_{SWF} \times g = 1.134\text{sg} \times 900\text{m} \times 0.0981 = 100.1 \text{ bar}$$

Overpressure at 900m TVD MSL:

$$P_{ob} = P^{UCA}_{lead} - P_{SWF} = 122.9 \text{ bar} - 100.1 \text{ bar} = 22.8 \text{ bar} \approx 331\text{psi}$$

Length of cement column:

$$L_{lead} = h_{SWF} - h_{sw} = 900\text{m} - 374\text{m} = 526\text{m} \approx 1726\text{ft}$$

CGS:

$$\Delta S^{gel}_{crit} = 300 \times \frac{P_{ob} \times (d_{OH} - d_{csg})}{4 \times L_{lead}} = 300 \times \frac{331\text{psi} \times (24" - 18.7")}{4 \times 1726\text{ft}} \approx 305 \text{ lbf/100ft}^2$$

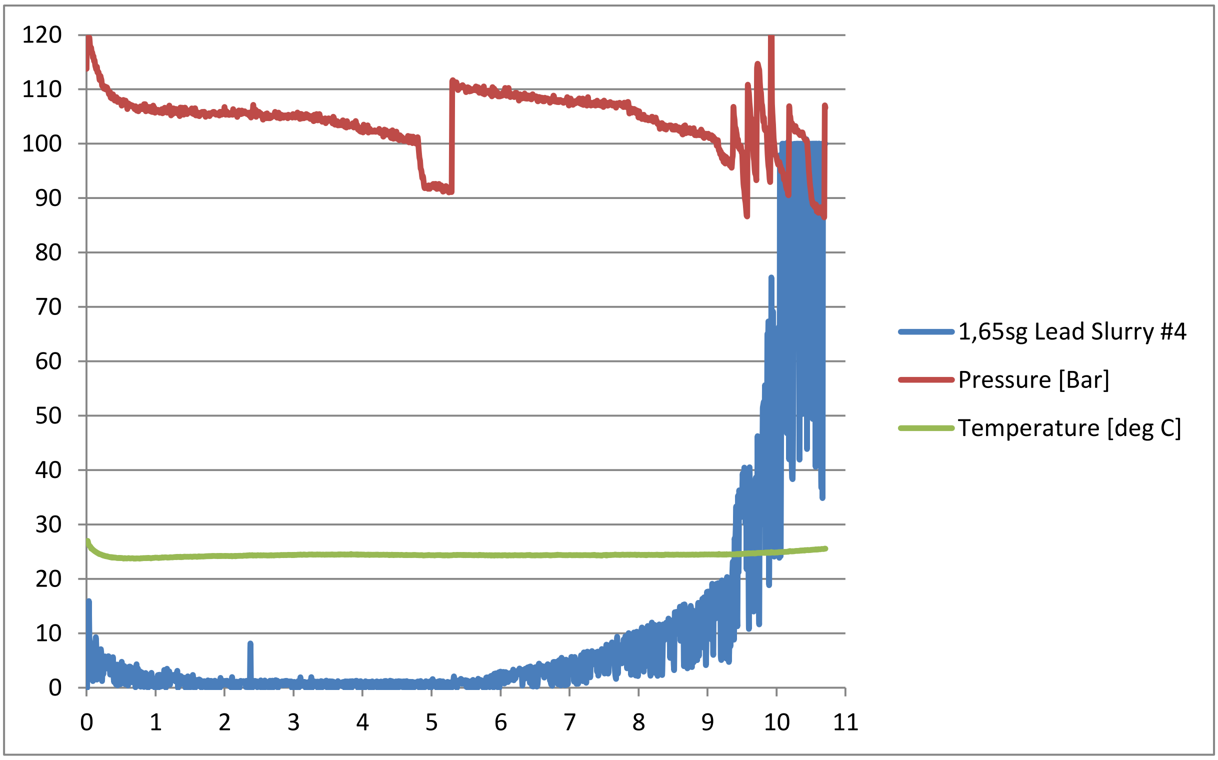

Figure 28: eskeeling 29032011 1.65sg lead test 3

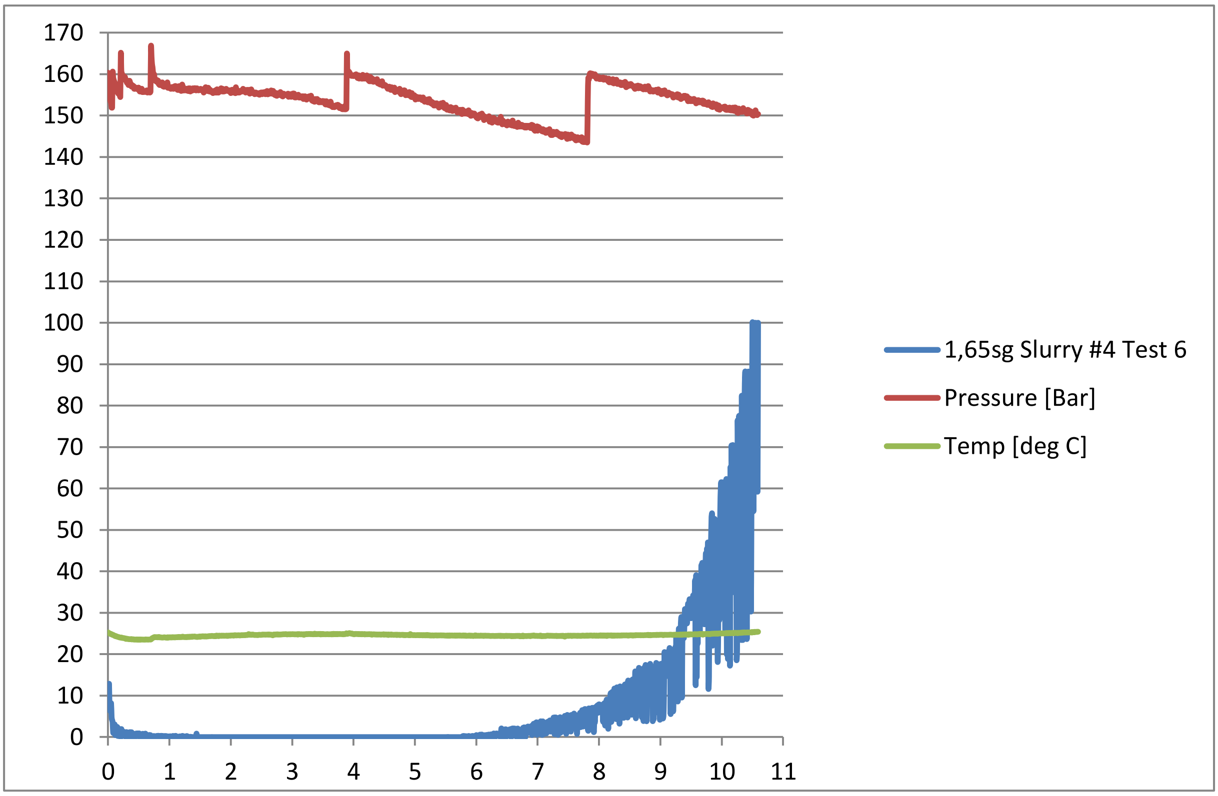

Figure 29: eskeeling 21042011 1.65sg lead test 6 150bar

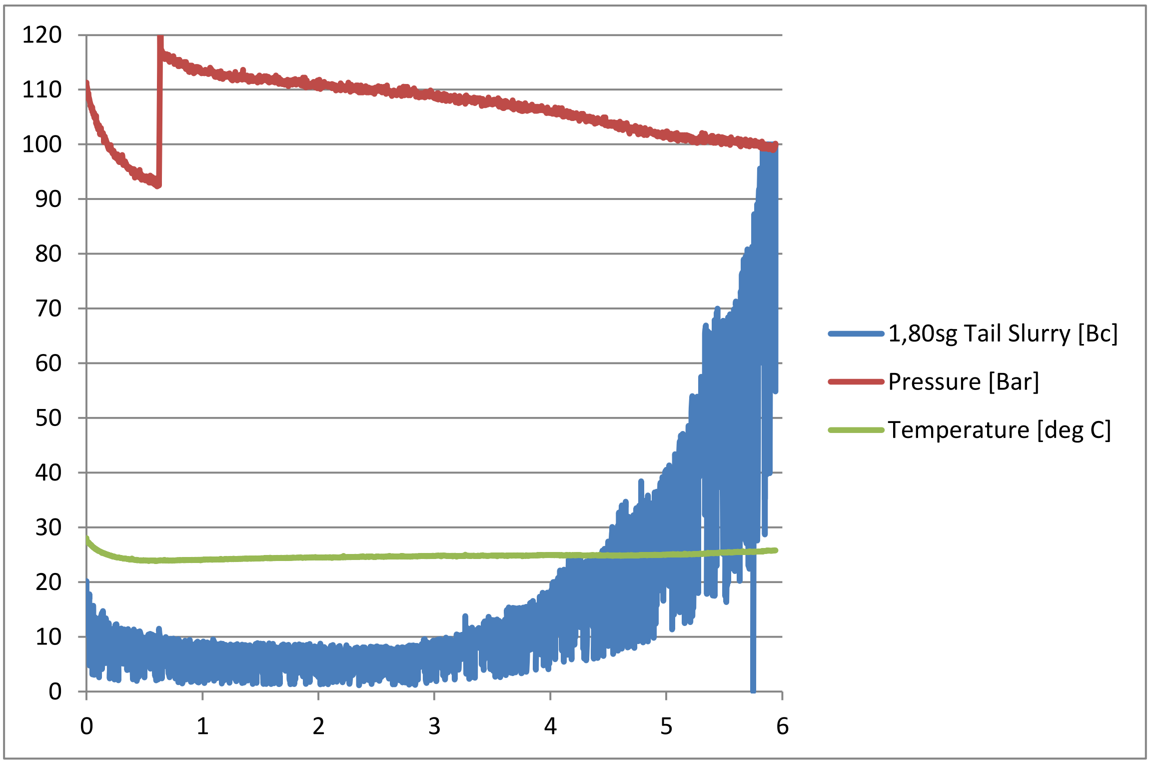

Figure 30: eskeeling 08042011 1.80sg tail test 2

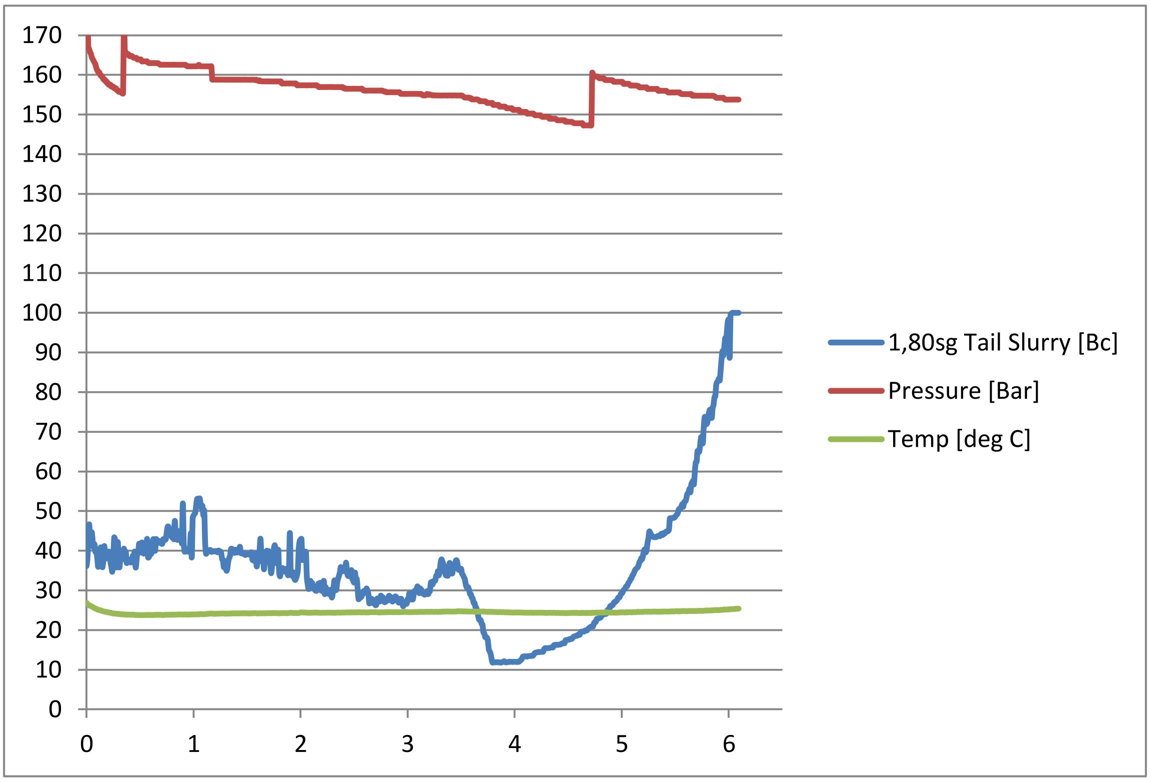

Figure 31: eskeeling 13052011 1.80sg tail test 10 150bar

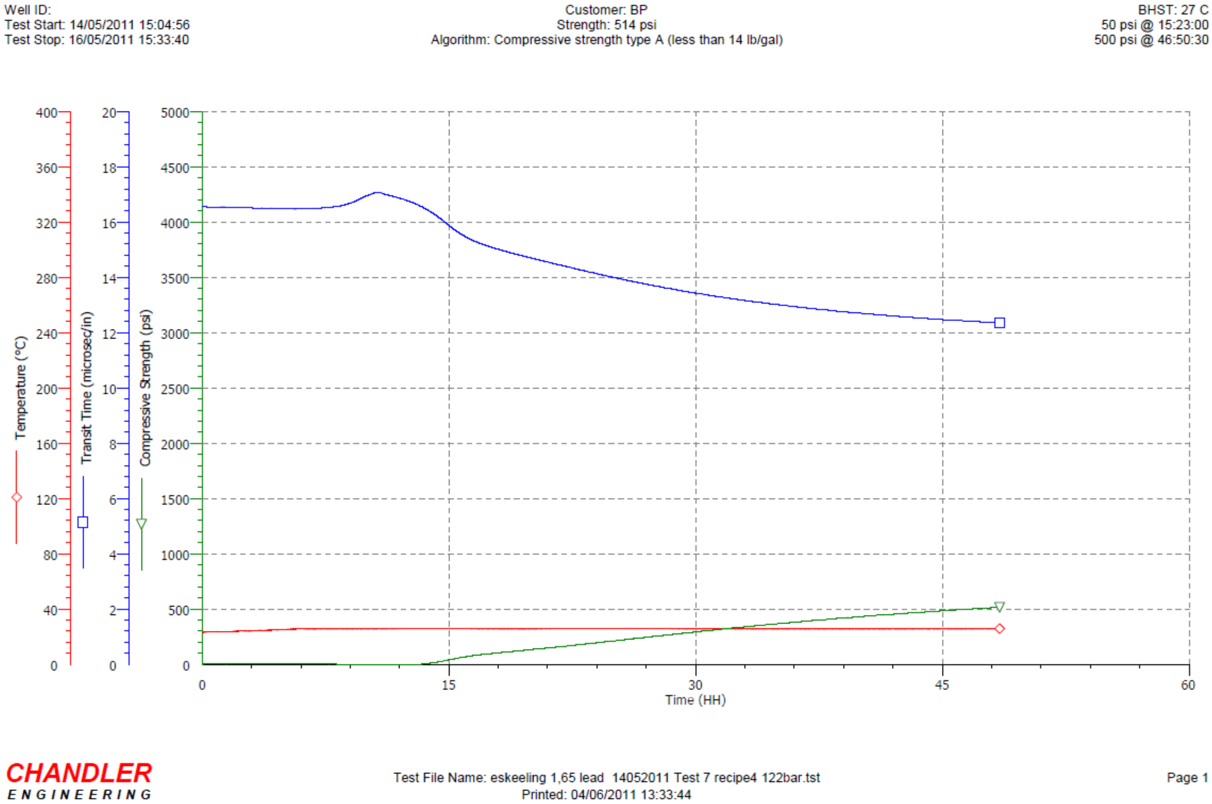

Figure 32: Compressive strength (green line) development of the 1.65sg lead slurry at downhole conditions (122bars/ 27°C) at 900m TVD MSL. Temperature (red line) and ultrasonic transit time (blue line) is also shown. (E.S. Keeling)

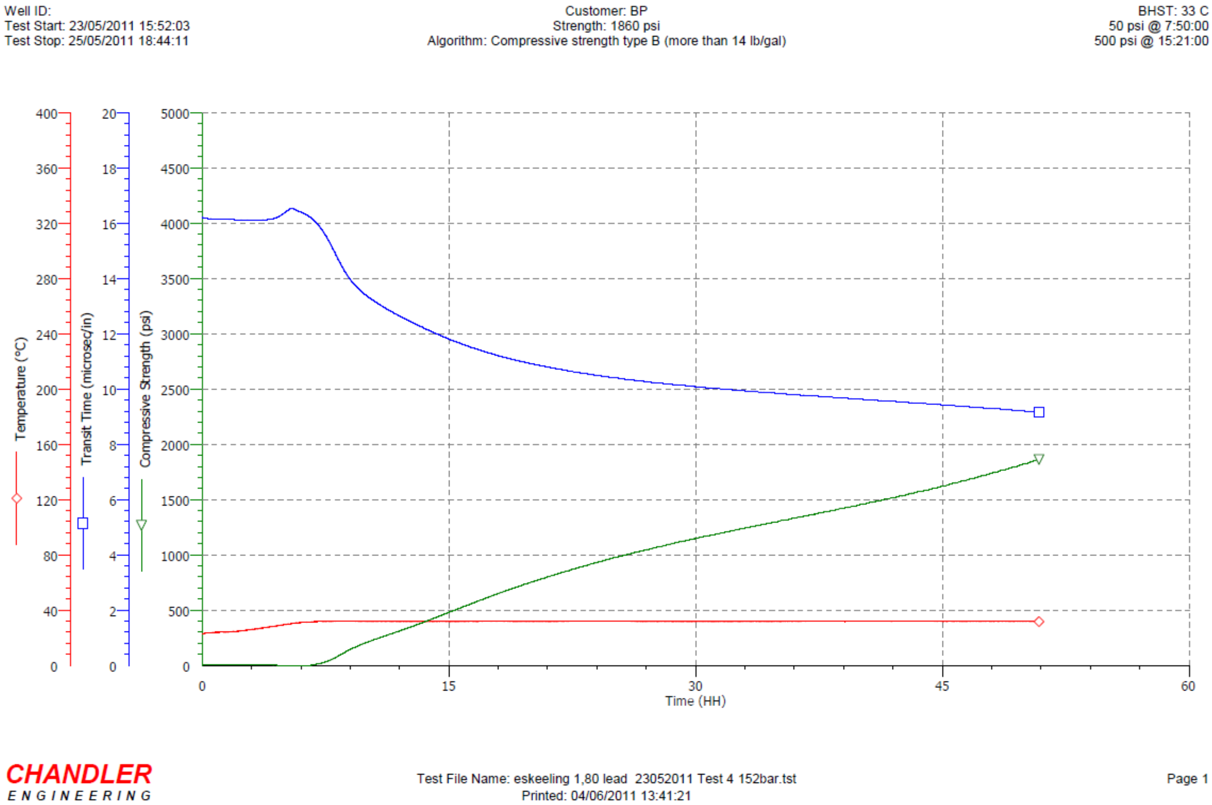

Figure 33: Compressive strength (green line) development of the 1.80sg tail slurry at downhole conditions (152bars/ 32°C) at 1070m TVD MSL. Temperature (red line) and ultrasonic transit time (blue line) is also shown. (E.S. Keeling