

Cementing Operations in Controlled Annular Mud Level Drilling

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Abstract

The petroleum industry has been making efforts since the 1990's to develop the dual gradient drilling technology. Currently, there are several available methods of achieving a dual gradient drilling, such as the Controlled Annular Mud Level (CAML). CAML system is capable of changing the bottom-hole pressure (BHP) by controlling the fluid level within the riser. All drilling fluid returns are pumped through a subsea pump attached to the riser. Changing the subsea pump rate will change the height of the fluid column inside the riser, thus controlling the BHP.

Most of the available studies have demonstrated how the CAML system works. Nevertheless, very few studies investigate the use of the CAML systems to assist in cementing operations. According to our knowledge, this work is the first one to investigate how the CAML system is useful in managing the BHP while cementing. A computational model was developed to simulate how a cement job can be performed when a CAML system is available. Twenty eight simulation cases were conducted in this study to investigate the controlling parameters as well as the benefits of using CAML systems over managed pressure cementing. These simulation cases are applicable for offshore wells with water depths ranging from 610 m to 1829 m (2000 ft to 6,000 ft) and operating windows as tight as 60 kg/m³ (0.5 ppg). The results show that CAML can maximize the open-hole length being drilled resulting in a minimum number of cement jobs and hence offers a minimum total cement operation cost. In addition, by changing the liquid level in the riser, CAML drilling may eliminate the need for multi-stage cementing. Therefore, it reduces the complexity of the operations as well as the number of cementing procedures. When compared with the conventional cementing operation, the CAML drilling allows using a higher cement slurry density and thus offers higher compressive strength cement. This high compressive strength leads to a better cement job and hence reduces the need for any future remedial cementing job.

Introduction and Literature Review

Dual Gradient Drilling (DGD) has gained widespread considerations in the drilling industry, especially after the

1990's. Since then, several companies have been making a lot of efforts to develop technologies capable of achieving a DGD status (Akers 2011; Brown et al. 2007; Rajabi et al., 2012). DGD has become very popular because of its ability to make drilling simpler, quicker and safer. Most features of DGD systems include: competency to drill areas previously considered not drillable, extend casing sections, gain riser margin, quicker kick detection, enhanced control of Bottom Hole Pressure (BHP), etc. (Stave, 2014).

One of the DGD systems is called Controlled Annular Mud Level (CAML) (Stave, 2014). A similar technique exists for riserless mud return during top hole offshore drilling (Landbo Opseth et al. 2009). CAML is also considered one of the Managed Pressure Drilling techniques used to control more precisely the BHP. CAML technique uses a subsea pump installed on the marine riser to control the fluid level within the riser. CAML systems can change the height of the fluid column inside the riser by changing the liquid flow rate of the subsea pump in comparison with the surface pump. Thus, the pressure imposed on formations will be changed by managing the height of the fluids inside the well.

The fluid level inside the riser of a CAML system can be controlled not only during drilling operations, but also when performing a primary cement job. CAML systems are able to control the drilling fluid level inside the riser as the cement is being pumped. The control of the height of the fluid column can avoid fracturing the formations during cementing operations. One of the reasons that makes companies choose multiple-stage cementing instead of the single-stage procedure is that the formations cannot stand the pressure imposed by a long sheath of cement. Controlling the drilling fluid level inside the riser is a promising way to maintain the BHP between the pore and fracture pressures as the cement is being pumped.

There are currently two CAML systems: EC-Drill® and Controlled Mud Pressure (CMP®). EC-Drill® was the first CAML method created with the main objective of controlling the well's pressure profile by changing the fluid level inside the riser. In addition, EC-Drill® could be used to extend casing sections by using higher density drilling fluids and evacuating larger sections of the marine riser (Nguyen et al. 2017). However, this technology is mainly used to control the

increased BHP created by the circulation of fluids during drilling. Using EC-Drill® to extend casing sections would require the creation of new well control methods and/or technologies to guarantee the safety of drilling operations (Falk et al., 2011). That is why the CMP® system has been created and seems to be in tests phase (Cohen et al., 2015). Although CMP® configuration looks very similar with EC-Drill®, CMP® seems to use a more robust equipment capable of dealing with denser fluids and also evacuating larger portions of the marine riser. Many papers have been written to clarify how EC-Drill® works and to show its advantages and limitations. However, very limited information has been discussed about the CMP® system. Cohen et al. (2015) have discussed some well control aspects of CMP® and introduced some characteristics of well cementing operations with CMP®. Nguyen et al. (2017) discussed the casing design applications for the CMP® technologies.

After the cement is placed, one needs to check for the potential of gas migration. Gas migration affects the quality and safety of a cementing job. This problem have been thoroughly studied since the 1960's and its on-set mechanisms seem to be well understood. According to Sabins et al. (1982), during the transition period of the cement, there is an observed reduction on the hydrostatic pressure transmitted by the column of cement to the formations. If the total reduction in the hydrostatic pressure exerted on the formations falls below the pore pressure of gas zones, it might generate a gas flow from the formations into the annulus. This undesirable flow might compromise the quality of the cementing procedure, resulting in an expensive remedial cementing job in the future.

During a primary cement job, the cement slurry must remain pumpable long enough to allow placement to the desired depth. This characteristic of the cement slurry can be controlled at the surface by using retarder and dispersant additives to control the thickening time and viscosity. Thickening time is a measurement of time during which cement slurry remain in a fluid state and is capable of being pumped. Therefore, right after completing a primary cementing job, the cement slurry usually behaves as a liquid (**Fig. 1a**). The hydrostatic pressure of the cement slurry at the depth of the gas zone is dependent mainly to the cement slurry density and the True Vertical Depth (TVD) of the gas zone. If the cement slurry density is design correctly, the static BHP at the gas zone will be greater than the formation gas zone pressure and thus formation gas cannot migrate into the annulus. After the cement has set and becomes completely solid (**Fig. 1c**), its compressive strength is sufficient to avoid the gas migration from the formation into the annulus. Between the liquid and solid phases, there is a transition phase at which the cement slurry behaves neither a true liquid nor a true solid. During this transition period, the gel strength of the cement slurry develops and thus the cement slurry has a plastic behavior (**Fig. 1b**). If the gel strength (a combined plastic and elastic property) of the cement slurry is high enough, part of the cement slurry weight will be supported by the casing wall and the open-hole wall. This will cause a

reduction in the static BHP. If this reduced static BHP is smaller than the formation gas pressure, the annular gas will flow in the annulus. This gas migration may be lost to the adjacent zones or percolate up to the surface.

Another reason for the reduction in static BHP is the fluid loss. There are two main reasons that cause the fluid loss: fluid loss to permeable zone through the mud-cake and fluid loss due to cement hydration. Because of the overbalanced pressure maintained during the primary cementing operations, some of the liquid leaks into the permeable zones. In addition, according to Complak et al. (1980), the liquid volume in the slurry may be reduced to 0.1 – 0.3 vol% because of the initial reaction between cement and water. The summation of these two fluid losses may sufficiently reduce static BHP at the gas zone to cause annular gas flow inside the the annulus.

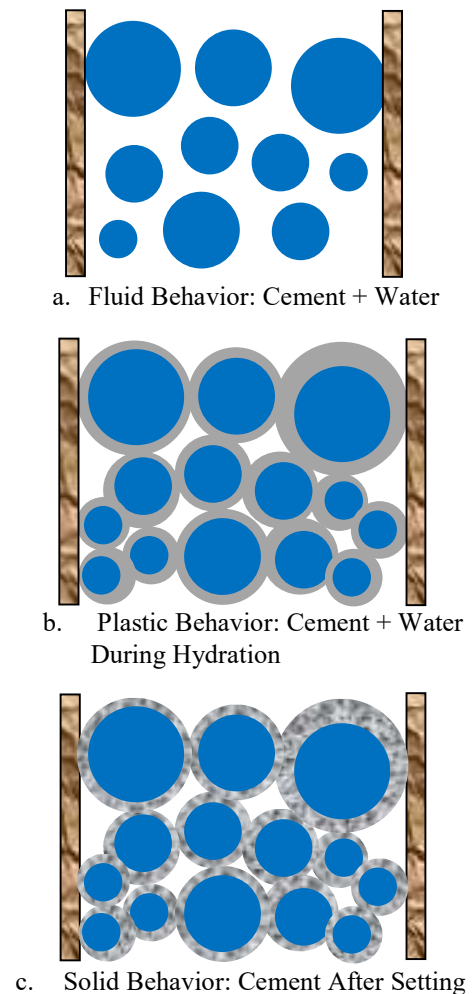


Figure 1: Cement hydration process
 Blue: cement particles; white: water; Gray: hydrates; Gray texture: crystalline structure

Sabins et al. (1982) defined the potential pressure restriction due to the static gel strength. The potential pressure restriction is the differential pressure between the initial static BHP and the static BHP at the gas zone depth at a given time. The potential pressure restriction is calculated using SI and field unit system is given in Eq. (1) and Eq. (2), respectively,

$$PPR = P_{wfi} - P_{wft} = SGS \frac{4L_c}{D_h - D_{cs}} \quad (1)$$

$$PPR = P_{wfi} - P_{wft} = \frac{SGS}{300} \frac{L_c}{D_h - D_{cs}} \quad (2)$$

where P_{wfi} and P_{wft} are the initial static BHP and static BHP at time t , respectively, L_c is the TVD from top of cement column to gas zone, D_h is the hole diameter, and D_{cs} is the outer casing diameter. In Eq. (1), the unit of pressure and static gel strength are in Pa, depth and diameter are in meter. In Eq. (2), the unit of pressure and static gel strength are in psi, depth and diameter are in inch.

Sutton et al. (1984) transformed Eq. (2) into a maximum pressure reduction considering a minimal static gel strength value of 240 Pa (500 lbf/100 ft²) that would restrict percolation of gas through the cement. Thus, Sutton provided Eq. (3), which explains the flow potential factor of a well based on a simple calculation:

$$FPF = \frac{MPR}{OBP} = \frac{1.67L_c}{OBP(D_h - D_{cs})} \quad (3)$$

where MPR is the cement maximum pressure reduction in psi, and OBP is the initial over and balance pressure in psi. During this transition, the hydrostatic head of the cement may be reduced, which may lead to a situation of gas migration from the formations to the well-bore. According to Sutton et al. (1984), if the flow potential factor is smaller than 1, there is no gas annular flow. A value of flow potential factor between 1 and 5 is considered moderate potential for gas flow; however it is still acceptable. A value of flow potential factor of higher than 5 is considered to have a great potential for gas flow.

According to Cummings et al. (2015), deep water and ultra deep water wells are those that have water depth greater than 500 m (1,600 ft) and 1500 m (5,000 ft), respectively. When drilling deep and ultra deep water wells, drillers may face with many different challenges including but not limited to narrow operating window, high water depth, high temperature and pressure, high power requirement at surface because of high drag and torque, inability of current tools. Narrow operating window and water depth are often the main concerns when designing, drilling, and completing these wells. High water depth may cause riser collapse and riser fatigue from vortex induced vibration, problem in holding the vessel against wind and currents, hydrate at the choke and kill lines (Cummings et al. 2015). Operating window is the differential pressure between formation pore and formation fracture pressures. As the water depth increases, the operating window gets narrower causing more challenge to complete a primary cement job because of the difficulties to control the BHP. In addition, Narrow operating window causes higher number of casings, smaller production tubing which may be too small to reach

economic production (Nguyen et al., 2017). The aim of this research is to study the benefits of using CAML drilling technique in primary cementing with the two main variables including the water depth and the operating window. A computer simulator was developed to study how wells are drilled and cemented using CAML systems. A sensitivity analysis was performed using the simulator to investigate the effect of operating window widths and water depth variations. The data obtained from the sensitivity analysis was used to evaluate topics such as stage cementing, implications of the use of denser cement and enhanced drilling fluid displacement with CAML systems.

Methodology and Computational Model Development

A computational model was developed in this research to evaluate the efficiency of cement job when a CAML system is used. As the cement slurry is pumped into the annulus between the casing and open-hole, flowing BHP is function of the rheological properties of drilling fluid and the cement slurry, flow regime in the annuli and in the return line, geometries of the well, and riser empty level. Fig. 2 illustrates a basic cementing operation using CAML technique.

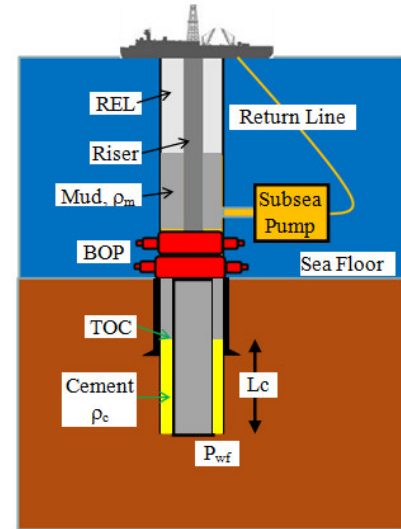


Figure 2: Schematic of a CAML Drilling

In general, the flowing BHP during the cement displacement when CAML is used can be calculated as follows:

$$P_{wf} = 0.052\rho_c L_c + 0.052\rho_m(TOC - REL) + \Delta P_c^{ann} + \Delta P_m^{ann} + \Delta P_m^{RL} + P_s \quad (4)$$

where ρ_c and ρ_m are the cement slurry and the drilling fluid densities in ppg, respectively; TOC and REL are the top of cement column and the riser empty level in ft, respectively; ΔP is the frictional pressure loss in psi. Conventional hydraulics model was applied to calculate for the frictional pressure loss in the annulus. Bingham Plastic and Power Law are the two rheological models considered in this study. Details of the conventional hydraulics model are presented in Table B1 in Appendix B.

The calculation of gas migrations is slightly different when

comparing cementing operation using CAML technique and using conventional drilling. The initial over balance pressure (psi) in CAML technique as a function of depth (x) is calculated as follows:

$$OBP(x) = 0.052[\rho_m(TOC - REL) + \rho_c(x - TOC - REL) - P_p x] \quad (5)$$

where REL is the riser empty level in ft as shown in **Fig. 2**. Therefore, Eq. (3) can be modified as:

$$FPF = \frac{1.67L_c}{(D_h - D_{cs})\{0.052[\rho_m(TOC - REL) + \rho_c(x - TOC - REL)] - P_p(x)\}} \quad (6)$$

Eq. (6) will be used to evaluate the flow potential factor for each layer on the open-hole section. After the cement placement, one can raise the riser empty level inside the riser to obtain smaller flow potential factor values. It is also important to highlight that the fracture pressure of the formations will be a limiting factor for raising the riser empty level, i.e. hydrostatic pressure in all open-hole layers has to be smaller than fracture pressure. If the hydrostatic pressure is higher than fracture pressure, there will be a fluid loss to the formations. This fluid loss, as noted before by Sabins et al. (1982) can also increase the potential for gas flow.

The above mathematical models were programed using Excel Visual Basic. Users input are pore and fracture pressures, wellbore geometries, fluid rheology, flow rate, and riser empty level. The simulator then outputs operating window, casing depth, static and flowing BHP, and details of cementing operation. In addition, the software also outputs the required number of sacks of cement and weighting materials, the volume of water, and the amount of each additive used for the cement job. A screenshot of the simulator and the calculation flowcharts are presented in **Figs. A1** and **A2**.

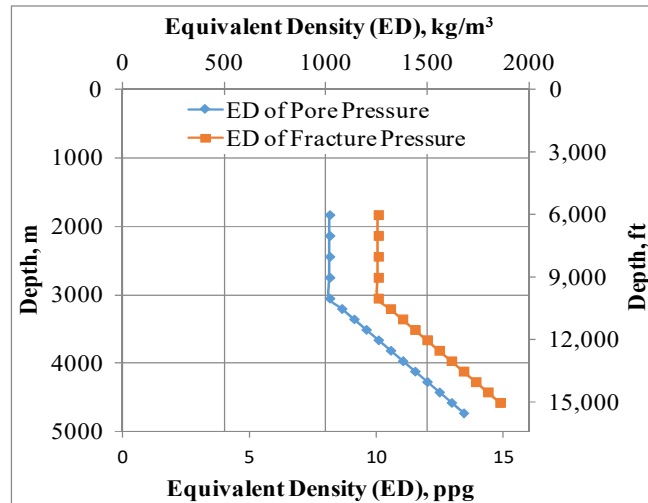


Figure 3 – An example of one case study: 2.0-ppg operating window and 6,000-ft water depth

A sensitivity analysis was carried out to study the benefits of using CAML drilling in cementing for twenty-eight different cases, as shown in **Table A1**. Each case had a different combination of an operating window width and a water depth. The considered operating window widths varied from 60–240 kg/m³ (0.5–2.0 ppg). The water depth range was from 610 to 2438 m (2,000 to 8,000 ft). Each well had a different water depth and operating window width, but had the same target depth from seafloor of 2591 m (8,500 ft). As shown in **Fig. 3**, the configurations of the operating window widths started with constant Equivalent Densities (EDs) or constant normal pore and fracture pressure gradients for 1219 m (4,000 ft) from seafloor (or 3048 m (10,000 ft) from the surface). Both pore and fracture pressure gradients had an increment of 0.1 ppg per 100 ft until they reach the target depth. The operating window width of each case was constant from top to bottom of each well. **Fig. 3** shows an example of a 240 kg/m³ (2.0 ppg) operating window width for 1829 m (6,000 ft) water depth well.

Result and Discussion

The main purposes of cement in oil and gas drilling are to keep the casing in place, form a permanent barrier against the formation fluids, and provide zonal isolation. The number of cement jobs to complete a well is totally dependent on the number casings run into the hole. Before looking into the benefits of using CAML drilling technique in cementing, let us review the advantages of CAML drilling in comparison with conventional drilling in terms of casing design. Nguyen et al. (2017) presented Eq. (7) to calculate the ED of drilling fluid at a given TVD.

$$ED = \rho_m \frac{TVD(x) - REL}{TVD(x)} \quad (7)$$

where x varies from the riser empty level to TVD. According to Eq. (7), ED in CAML drilling is not a constant even though the drilling fluid density is constant. At a riser empty level of 1000 m, ED of the drilling fluid will be zero from surface to depth of 1000 m. Then ED values increase as TVD is higher. In other words, the relationship between ED and TVD in CAML is nonlinear, as opposed to vertical line as in conventional drilling. To demonstrate this concept, let's consider the case study presented in **Fig. 3** where the operating window is 240 kg/m³ (2 ppg) and the water depth of 1830 m (6,000 ft). Conventional casing design suggests four casing strings including a production casing to complete this well as shown in **Fig. 4**. The depths of each casing are 3100 m, 3700 m, 4200 m, and 4700 m, respectively. If CAML is applied and the riser empty level is maintained at 915 m (3,000 ft), the number of casings is reduced to two at depths of 3800 m, and 4700 m to complete this well as shown in **Fig. 5**. Generally speaking, by changing the value of riser empty level, the number of casings in CAML drilling required to complete an offshore well is less than that of conventional drilling. This leads to a reduction in the number of cement jobs and hence reduces the total cost required to complete the well. In

addition, CAML drilling offers a much longer open-hole length drilled. Fig. 5 shows that when using CAML drilling, there are two open-hole sections at the depths of 3800 m and 900 m (4700 – 3800 = 900 m). Meanwhile, conventional drilling requires four shorter open-hole sections with depths of 3100 m, 600 m, 500 m, and 550 m. In general, the maximum open-hole length drilled (the longest open-hole section) is much higher when using CAML drilling than conventional drilling.

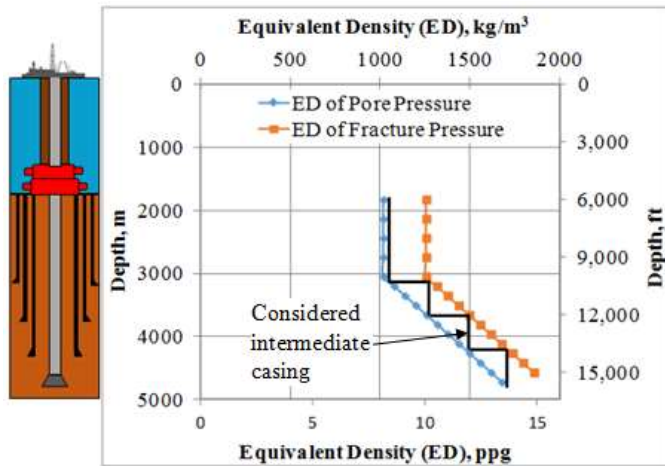


Figure 4: Casing design example for conventional drilling – REL = 0 m

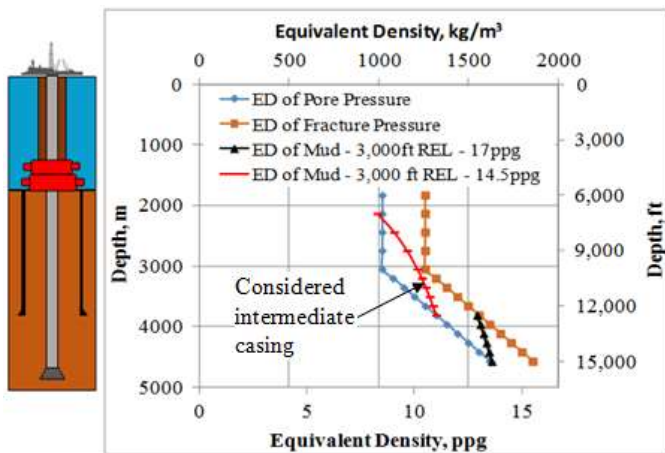


Figure 5: Casing design example for CAML drilling REL = 914 m = 3,000 ft

Fig. 6 shows the relationship between the maximum open-hole length for the considered intermediate casing as shown in Figs. 4 and 5 and the operating window width for twenty-eight cases of CAML drilling as presented in Table A1. To compare the maximum open-hole length when using CAML drilling and conventional drilling, the same relationship for conventional drilling with varying two water depth values of 609 m (2,000 ft) and 1829 m (6,000 ft) and seven operating window widths varying from 60–240 kg/m³ (0.5–2 ppg) were also presented in Fig. 6. The dashed and solid lines in Fig. 6 represent this relationship when using conventional drilling and CAML drilling systems, respectively. The data indicates

that for the conventional drilling cases, the operating window width is much more sensitive than the water depth to increase the drilled maximum open-hole length. By increasing the operational window from 60–240 kg/m³, the average length of drilled section expanded from 70 to 530 m, which is 7.7 times deeper. However, when changing the water depths from 609 m to 1829 m, the results show a minimum impact of water depths on the maximum open-hole length. The two lines representing 609 m and 1829 m are almost identical.

However, when using CAML drilling (solid lines), the maximum open-hole length is affected not only by the operating window widths, but also by the water depths. Note that the riser empty level value in all simulations in this study was set at 500 ft less than water depth. This means the higher water depth value is, the higher riser empty level value will be. For the water depth of 1219 m (4,000 ft) and the operating window width of 240 kg/m³ (2 ppg), conventional drilling and CAML drilling extend maximum open-hole length with a magnitude of 7.7 and 24.5 folds, respectively. This significant increase in maximum open-hole length when using CAML drilling is due to higher water depth, which gives more room for the subsea pump to empty the riser, gaining more control over the BHP. In other words, higher water depths will represent the possibility of using larger riser empty level to control the BHP. The better control of BHP, results in longer drilled open-hole sections, and hence reduces the number of casing strings and cement jobs. The maximum value of the riser empty level is mainly dependent on the critical collapse pressure of the riser. Thus, the maximum open-hole length will also be affected by the critical riser collapse pressure. A closer look of the results reveals that as the water depths are in the range from 1219 m (4,000 ft) to 1829 m (6,000 ft), and operating window are higher than 180 kg/m³ (1.5 ppg), the increase in the maximum open-hole length is minimum. This limitation is because of the abnormal pore pressure occurred at 10,000 ft or the change in the slope of pore and fracture pressures at 10,000 ft. CAML drilling allows us to control the riser empty level, and hence modify the drilling fluid pressure gradient to fit within the abnormal operating window at deeper than 10,000 ft as shown in Fig. 5. However, this pressure gradient modification will be limited by the normal pressure gradients (shallower than 10,000 ft).

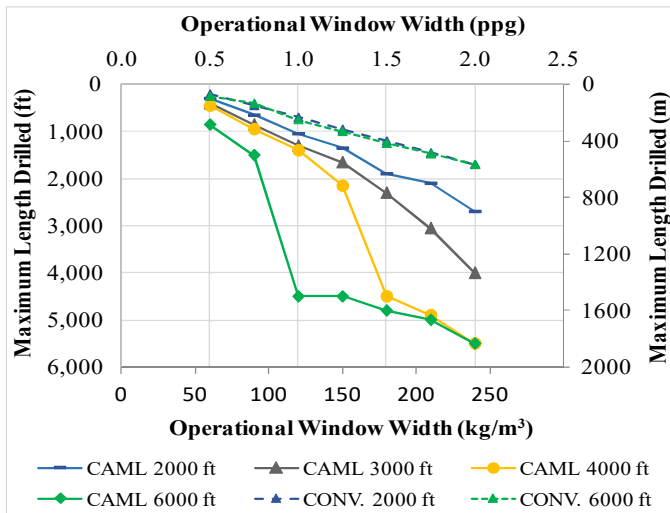


Figure 6: Maximum length drilled for each case

Fig. 7 shows the benefits of using CAML drilling in cementing when compared with conventional drilling in cementing. The simulations were carried out for four operating window values and each with three different water depths. The length of the cement column when using conventional drilling and CAML drilling was compared against each other for one specific water depth and operating window. Note that the results in Fig. 7 were performed for the intermediate casing which is just outside the production casing as shown in Figs. 4 and 5. The blue and red columns in Fig. 7 represent the first stage and second stage of cementing, respectively. The simulation results pointed out that all of the twelve maximum open-hole length drilled using conventional drilling had to perform a second stage cement operation to complete the cement job for the considered casing without fracturing the formations. However, all the other twelve CAML simulations required only a single stage cement operation to complete the cement job. The two main reasons for having multi-stage cementing in conventional drilling are: high density cement slurry, and high frictional pressure loss in the annulus because of large number of casing strings. Both reasons will contribute to elevate the well pressure while cementing. When the formations cannot support the fracture pressures generated by the cement placement, the operation needs to be done in multiple stages. However, CAML systems can reduce the fluid level while cementing, compensating for the increase of the pressures within the well. This ability may eliminate the need for multi-stage cementing, reducing the complexity of the operations as well as the number of cementing procedures. Not only CAML enables single stage cement all cases studied, but also the CAML cemented sections were a lot deeper if compared with conventional cementing, especially for the cases at larger water depths. The reduction on the number of stages needed for each procedure and the increase on the size of the open-hole drilled section will contribute to minimize the non-productive time due cementing operations.

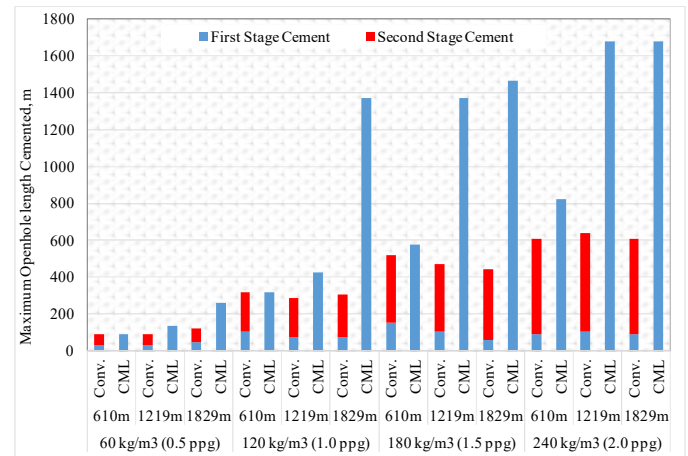


Figure 7: Comparison between the numbers of cementing stages performed at each case

To better understanding the results in Fig. 7, let's review the case at which the operating window is 240 kg/m³ (2 ppg), and the riser empty level of 914 m (3000 ft) as shown in Figs. 4 and 5. These two figures indicate that MOLs for the considered intermediate casing are about 600 m and 1700 m. If the cement operation was performed using the conventional drilling, a two-stage cement was required to avoid the fracture of the formations. The total length of the two stage cement as shown in Fig. 7 is about 600 m. However, if the cement operation was performed using CAML drilling with riser empty level of 914 m, only single stage cementing is needed and the total length of this cement column is about 1700 m as shown in Fig. 7. Note that as shown in Fig. 6, increasing water depth from 1219 m to 1829 m and operating window from 180 kg/m³ to 240 kg/m³ to have higher values riser empty level does not extend the maximum open-hole length and hence does not increase the length of the cement column.

Another important factor was the difference between cement slurry density used in conventional and CAML operations. Because CAML drilling empties portions of the riser, the fluids using in those operations are much denser than that in conventional drilling. Fig. 8 exhibits a comparison between average cement slurry density for both conventional and CAML techniques at different water depths. In all cases, density of cement slurry used in CAML drilling was higher than that in conventional cementing. Cements with higher densities normally develop higher compressive strength after they are set. Higher compressive strength contributes to a more efficient cement job, and reduces any future remedial cementing job.

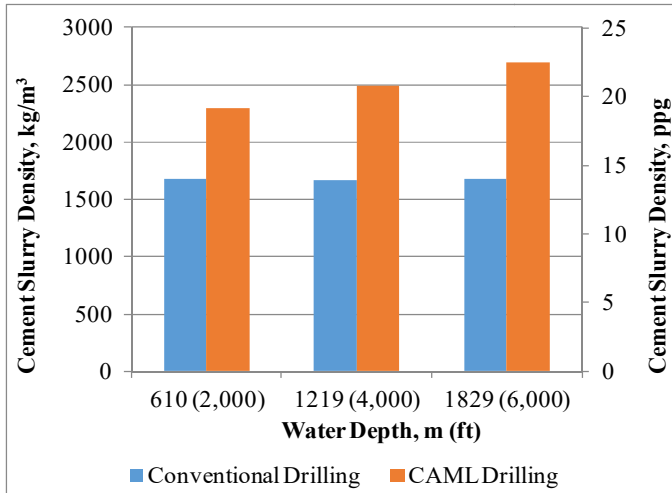


Figure 8: Comparison of cement slurry density between CAML & conventional drilling

To investigate gas migration, sixteen simulation runs were carried out to evaluate the flow potential factor variation as a function of depth, using Eq. (6). As stated in the introduction and literature review, a flow potential factor smaller than one is the desirable for gas saturated permeable formations. Values of flow potential factor between one and five have moderate potential for gas flow. With flow potential factor values higher than five, additional steps were taken to make the flow potential factor values at least acceptable (Sutton et al. 1984). If flow potential factor is higher than five, the first step is to increase the fluid level inside the riser after placing of cement using the subsea pump. This fluid level management compensates for the maximum pressure reduction of the cement slurry during setting period. If the management of fluid level inside riser after cement circulation is not enough to compensate for maximum pressure reduction, a second decision has to be made. If legislation permits, the length of the sheath of cement can be reduced. Some legislations permit that cement column can be smaller than actual measured open-hole depth. If none of the actions cited before turn out being a solution for gas migration, multiple-stage cementing should be considered.

Fig. 9 shows the results of gas migration simulation runs for the case of 1829 m (6,000 ft) water depth and 240 kg/m³ (2.0 ppg) operating window. The solid line represents the results for the initial flow potential factor simulation runs, before any actions were taken. For the initial situation, maintaining the riser empty level of 1677 m (5,500 ft), a considerable part of the solid line is located on the red zone at which the flow potential factor is greater than 5. To mitigate annular gas, the first step is to reduce the riser empty level down to 1463 m (dashed line). This is the smallest value of riser empty level to prevent the formation fracture. Fig 9 revealed that only reducing the riser empty level inside the riser was not sufficient to reduce flow potential factor profile to the acceptable zone (flow potential factor < 5). Therefore, a second action was simulated by reducing the length of the column of cement by 20% or from 1677 m (5,500 ft) to 1341

m (4,400 ft) as shown in the dotted line. In other words, for all cases studied, if flow potential factor was higher than five, at first, the fluid level inside the riser was increased, i.e. decreasing the riser empty level. If this action is not sufficient to reduce flow potential factor below five, then the length of cement column is reduced.

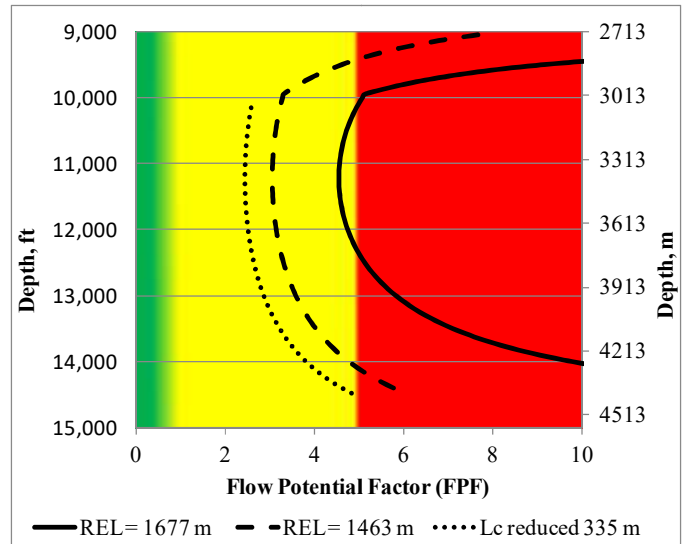


Figure 9: Flow potential factor simulation (2,000 ft water depth and 2 ppg operational window width)

Table 1 - Summary of gas migration simulations

Water Depth	Operational Window Width	Initial Fluid Level	Increased Fluid Level	Lc reduction	% of Lc Reduction
2,000 ft	0.5 ppg	1,980 ft	1,700 ft		
	1.0 ppg	2,000 ft	1,700 ft		
	1.5 ppg	2,000 ft	1,710 ft		
	2.0 ppg	2,000 ft	1,700 ft	200 ft	7%
4,000 ft	0.5 ppg	3,820 ft	3,550 ft		
	1.0 ppg	4,000 ft	3,650 ft		
	1.5 ppg	4,000 ft	3,810 ft	2,350 ft	52%
	2.0 ppg	3,700 ft	3,450 ft	3,350 ft	61%
6,000 ft	0.5 ppg	5,950 ft	5,700 ft		
	1.0 ppg	6,000 ft	5,750 ft	1,700 ft	38%
	1.5 ppg	5,900 ft	5,540 ft	200 ft	4%
	2.0 ppg	5,150 ft	4,800 ft	1,100 ft	20%

Table 1 summarizes all results for gas migration simulations. In cases which local regulation would not permit to reduce the L_c or for cases where the reduction of L_c is too significant, it would be necessary to perform the cementing of those wells in multiple staging. Also, if L_c cannot be reduced because there are shallow formations that need to be isolated by cement, multiple-stage cement should be performed.

Nine out of the sixteen cases studied experienced a reduction in L_c. Three cases had to reduce its column of cement in less

than 10% of the original size. Other three cases experienced a reduction in L_c between 20% and 25%, and the remaining three cases had this reduction percentage higher than 25%.

Concluding Remarks

In this study, a predictive simulation tool was developed to evaluate cement job when a CAML system is being implemented. A sensitivity analysis was carried out to investigate the value of using CAML drilling in cementing through simulating twenty-eight cases. Each case has a different water depth and an operating window, but it had the same target depth from seafloor. The results of this study can be summarized as follows:

1. CAML can maximize the drilled maximum open-hole length, resulting in a minimum number of casings and number of cement jobs, thus minimum total cement operation cost.
2. By changing the riser empty level, CAML drilling may eliminate the need for multi-stage cementing, reducing the complexity of the operations as well as the number of cementing procedures.
3. For a given pore and fracture pressure profiles, when the operating window is higher than 180 kg/m³ (1.5 ppg), riser empty level of 1067 m is an optimal value to obtain the maximum value of maximum open-hole length or minimum cement operation cost.
4. CAML drilling enables using higher cement slurry density compared with that used in conventional drilling due to flexibility of changing riser empty level. Higher density cement slurries provide higher compressive strength leading to a better cement job, reducing the need of future remedial cementing jobs.

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Nomenclature

BHP	= Bottom hole pressure, Pa (psi)
CAML	= Controlled annular mud level.
CMP	= Controlled Mud Pressure
D_{cs}	= Outer diameter of casing, m (inch)
D_h	= Hole diameter, m (inch)
D_i	= Inner diameter of annulus, m (inch)
D_o	= Outer diameter of annulus, m
f	= Friction factor
FPF	= Flow potential factor
g	= Acceleration of gravity, m/s ²
K	= Consistency index, Pa.s ⁿ (lbf.S ⁿ /100ft ²)
L	= Total length of the annulus, m (ft)
L_c	= Cement column length, m (ft)

MPR	= Maximum pressure reduction, Pa (psi)
n	= Power law index of flow behavior
OBP	= Initial overbalance pressure, Pa (psi)
PPR	= Potential pressure restriction, Pa (psi)
Re	= Reynolds number
REL	= Riser empty level, m (ft)
SGS	= Static gel strength, Pa (lbf/100 ft ²)
V	= Fluid velocity, m/s (ft/s)
TOC	= Top of cement, m (ft)
TVD	= True vertical depth, ft (m)
x	= Depth of interest, ft
ΔP	= Pressure Losses, Pa
μ_c	= Equivalent viscosity, cp (Pa×s)
μ_p	= Plastic viscosity, cp (Pa×s)
ρ	= Density, kg/m ³ (lbf/gal)
ρ_c	= Cement density, kg/m ³ (lbf/gal)
ρ_m	= Mud density, kg/m ³ (lbf/gal)
τ_y	= Yield point, Pa (lbf/100ft ²)

Subscripts

c	= Cement
cs	= Casing
i	= Inner
o	= Outer
m	= Mud
s	= Surface

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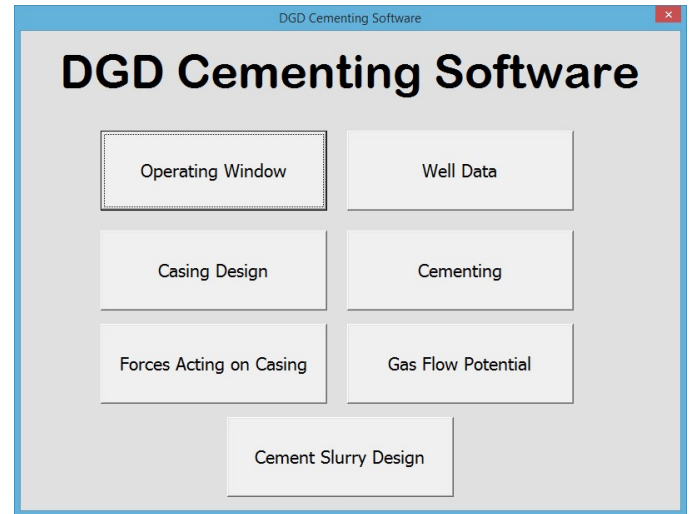


Figure A1: Screenshot of the simulator

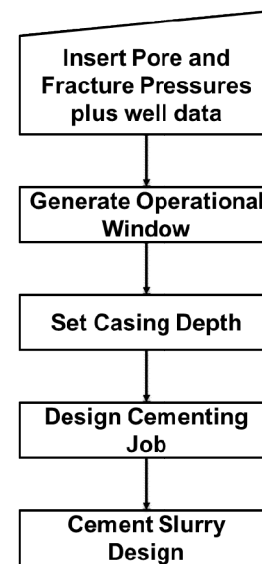


Figure A2: Steps followed by the simulator

Appendix A

Table A1: Description of twenty eight cases studied

Water Depth ft (m)	2,000 (610)						
Operating window ppg (kg/m ³)	0.50 (60)	0.75 (90)	1.00 (120)	1.25 (150)	1.50 (180)	1.75 (210)	2.00 (240)
Water Depth ft (m)	3,000 (914)						
Operating window ppg (kg/m ³)	0.50 (60)	0.75 (90)	1.00 (120)	1.25 (150)	1.50 (180)	1.75 (210)	2.00 (240)
Water Depth ft (m)	4,000 (1219)						
Operating window ppg (kg/m ³)	0.50 (60)	0.75 (90)	1.00 (120)	1.25 (150)	1.50 (180)	1.75 (210)	2.00 (240)
Water Depth ft (m)	6,000 (1829)						
Operating window ppg (kg/m ³)	0.50 (60)	0.75 (90)	1.00 (120)	1.25 (150)	1.50 (180)	1.75 (210)	2.00 (240)

Table B1 – Conventional Hydraulic Model for Calculating the Frictional Pressure Loss in Annuli

	Model	Annular Flow
Laminar Flow	Bingham (Re ≥ 2100) $Re = \frac{0.8165(D_o - D_i)V\rho}{\mu_e}$	$f = \frac{16}{Re} \quad \Delta P = \frac{48L\mu_e V}{(D_o - D_i)^2} \quad \mu_e = \mu_p + \frac{\tau_y}{12V/(D_o - D_i)}$
	Power Law (Re ≥ 3470 - 1370n) $Re = \frac{2.45n(D_o - D_i)V\rho}{\mu_e(2n + 1)}$	$\Delta P = \frac{48L\mu_e V}{(D_o - D_i)^2} \frac{2n + 1}{3n} \quad \mu_e = K \left(\frac{12V}{D_o - D_i} \frac{2n + 1}{3n} \right)^{n-1}$
Turbulent Flow	Bingham (Re ≥ 2100) $Re = \frac{0.8165(D_o - D_i)V\rho}{\mu_e}$	$f = \frac{0.05}{Re^{0.2}} \quad \Delta P = \frac{0.127L\rho^{0.8}V^{1.8}\mu_p^{0.2}}{(D_o - D_i)^{1.2}}$
	Power Law (Re ≥ 3470 - 1370n) $Re = \frac{2.45n(D_o - D_i)V\rho}{\mu_e(2n + 1)}$	$f = \frac{c}{Re^b} \quad \text{where } c = \frac{\log n + 2.5}{50} \quad b = \frac{1.4 - \log n}{7}$ $\Delta P = \left(\frac{2cL\rho^{1-b}V^{2-b}}{[0.8165(D_o - D_i)]^{1+b}} \right) \left[\mu_e^b \left(\frac{2n + 1}{3n} \right)^b \right]$ $\mu_e = K \left(\frac{12V}{D_o - D_i} \frac{2n + 1}{3n} \right)^{n-1}$

Appendix B

Flowing BHP is calculated by the sum of the hydrostatic pressure and the friction pressures generated by circulation of the fluids in the annulus. Table B1, modified from the Drilling Mud and Cement Slurry Manual (1982), shows the equations to calculate the frictional pressure drop under flowing conditions.

The calculation of the flowing BHP follows the steps shown in Table B1. All steps are repeated for each different annular section of the well, such as: open hole and Bottom-Bole Assembly (BHA); open hole and drill pipes; casing and drill pipes; riser and drill pipes; open hole and casing (cementing); larger casing and new casing (cementing). For Bingham simulations, the first step is to calculate the equivalent viscosity (μ_e) and the Reynolds number (Re) to determine what flow regime will be considered. After setting the type of flow, the software calculates the frictional pressure drop (ΔP) for each section of the well. The process is very similar for Power Law fluids, however, before calculating the ΔP in turbulent flow, the parameters “b” and “c” need to be determined.