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Deepwater Reverse-Circulation Primary Cementing: Applicability and Technical Path Forward for Implementation

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Abstract

A two-year government funded project is being conducted to evaluate the viability and applicability of Reverse-Circulation Primary Cementing (RCPC) in deepwater wells. This project focuses on the identification of technical issues that must be addressed before routine RCPC operations can occur in deepwater wells, and a recommended path forward to full evaluation of the viability of this placement technique in deepwater. Analysis includes numerical models and simulations, mechanical placement controls, cementing materials, and operational challenges.

While RCPC has been used on land and on a few shallow water offshore wells, it has not yet been fully evaluated for use in a challenging deepwater environment. The application of RCPC to deepwater wells is expected to reduce bottom-hole circulating pressures and prevent lost circulation during cementing, as well as increase safety, environmental sustainability, zonal isolation, and improve cement seals.

Standard commercially available software packages are unable to directly model the flow path through the complex configuration of a deepwater reverse-circulation cementing process. A multi-physics finite-element software package has been used to develop a model to predict temperatures and pressures during the reverse-circulation cementing process. Evaluation of mechanical placement controls has found that a major challenge will be the development of a switchable crossover between a conventional and reverse flow path, and the modification of float equipment. Also, with the application of RCPC it is anticipated that the design methodology of cementing fluids may be affected by changing the placement method.

One major challenge in deepwater cementing is the narrow formation fracture gradient, so the application of RCPC has clear beneficial potential. By lowering the Equivalent Circulation Densities (ECDs) during the job, the risk of fracturing the formation and lost-circulation is decreased. Less fluid lost to the formation during placement can potentially lead to higher tops of cement (TOC) and improved cement bonding and zonal isolation.

Introduction

Background

Reverse-Circulation Primary Cementing (RCPC) is an infrequently used placement technique where cementing fluids are placed down the annulus with returns taken up the casing, in contrast to conventional circulation where fluids are pumped down the casing then up the annulus. Placement through reverse circulation has been in use since the 1960s; in 1965 a reverse cementing technique was used to cement production strings in weak formations, which resulted in higher allowable flow rates during placement and improved bond logs (Marquaire, 1965). Applications over the years have included casing repair, tiebacks, and production strings. This placement technique was typically used in wells with low formation fracture pressures and high risk of lost circulation, where conventional placement would have been difficult to execute successfully.

Hernandez and Bour (2010) documented 26 successful cases of RCPC in geothermal land wells between 2002 and 2009 using both conventional and foamed cement slurry systems. In these wells, RCPC placment was selected because of the resulting redcuced equivalent circulating densities (ECDs) and hydraulic horsepower (HHP), since fluid placement down the annulus is assisted by gravity. Common challenges seen in these wells was in determining when cement slurry reached the shoe and availablity of float equipment, since conventional float equipment cannot be used with RCPC.

While the majority of documented RCPC jobs have occurred onshore, a few offshore applications in shallow waters have been seen. Placement by reverse circulation was first used offshore in the Gulf of Mexico Mobile Bay area for two production tiebacks in high pressure-high temperature (HPHT) wells, which allowed for the staging of retarding additives to improve compressive strength development along the full length of the annulus (MacEachern et al., 2003). Reverse circulation was also used to cement an offshore liner lap in the Arctic where conventional placement would have broken down the formation due to tight annuli and low frature gradient (Mariott, 2007).

In general, benefits seen during past RCPC jobs include reduced ECDs compared to conventional jobs, improved zonal isolation, reduced risk of lost circulation, higher TOC, shorter placement times, and a reduction in the amount of retarding additives used. Due to the narrow pore-frac gradient and narrow casing-in-casing annuli commonly seen in deepwater wells, a placement technique that could reduce ECDs during cementing would bring clear benefit both operationally and environmentally.

Before RCPC can be applied to a challenging deepwater environment, a full evaluation is needed to determine if the benefits seen onshore are both viable and transferable to deepwater. In addition, technical gaps and contingency scenarios must be addressed before RCPC operations can occur in deepwater wells. Complex deepwater well architecture and operational parameters adds to the typical challenges seen during the execution of past RCPC jobs.

Figure 1 compares the flow path of a conventional liner configuration to an expected RCPC configuration. In a conventional liner job, fluids are pumped from the rig floor down a work string that runs down the riser below the BOP, connecting to the liner string. Fluids are pumped down the liner and up into the annulus. For RCPC to be applied to deepwater, fluids will still need to be pumped from the rig floor through a workstring with injection into the annulus occurring at a point below the BOP stack to avoid cement in the riser and BOP. A specialized crossover tool will be needed to divert fluids into the annulus. Fluids will then be pumped down the annulus and return up the liner string, diverting back through the crossover tool into the previous casing and riser annulus.

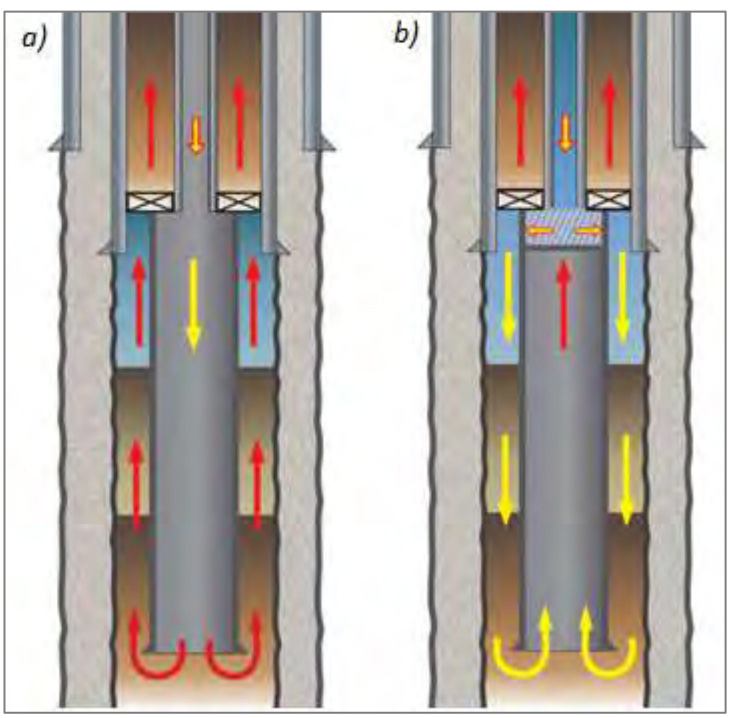

Figure 1: Flow path of fluids during conventional placement (a) and reverse placement (b) in a deepwater liner

Technical Challenges

Due to the complex flowpath of deepwater RCPC, a major challenge is the availability of specialized crossover tools to circulate the well and perform RCPC operations. Since conventional plugs and float equipment cannot be used, alternative tools and methods need to be developed to accurately identify when cement reaches the casing shoe to avoid either incomplete cementation around the shoe or a large amount of cement to drill out. An evaluation of the current state of tool technology and expected tool requirements will be detailed in this paper.

Computer simulation and modeling are necessary for all cementing jobs for parameters such as ECDs, pump rates, friction pressures, and mud removal efficiency. Standard commercially available simulation software was developed for conventional placement, and those simulators that are capable of handling reverse placement can do so only in a straightforward configuration, such as during an onshore job where fluids are injected directly into the annulus at the surface. Commercially available simulators are currently unable to model complex configurations, where flow is diverted back and forth through a crossover. This challenge will need to be addressed before RCPC can be applied to deepwater, either through workarounds within existing commercial simulation software or through the development of a model specificially tailored to deepwater RCPC. Preliminary results of a custom finite-elemenet model for deepwater RCPC will be discussed further in this paper.

Other considerations for deepwater RCPC include cement slurry design modifications. Previous applications of RCPC have shown that additives can be staged to reduce waitring-on-cement (WOC) time and improve compressive strength development throughout the cement column. Since the cement slurry pathways are not expected to be the same as those seen during conventional placement, effects of these downhole fluid temperature profiles on deepwater RCPC fluids and designs will also be discussed in this paper.

Discussion

Mechanical Placement Equipment.

State of Current Technology. The most common form of reverse cementing is done when access to the outside (OD) of the casing is accessible at the surface. This allows the pumping of cement down the OD of the casing and the inside diameter (ID) of the hole with returns being taken up the inside (ID) of the casing. Some operators use an inner string of drill pipe or tubing inside the ID of the casing to reduce the time it takes to get returns back to the surface. Examples of this are shown in Figure 2.

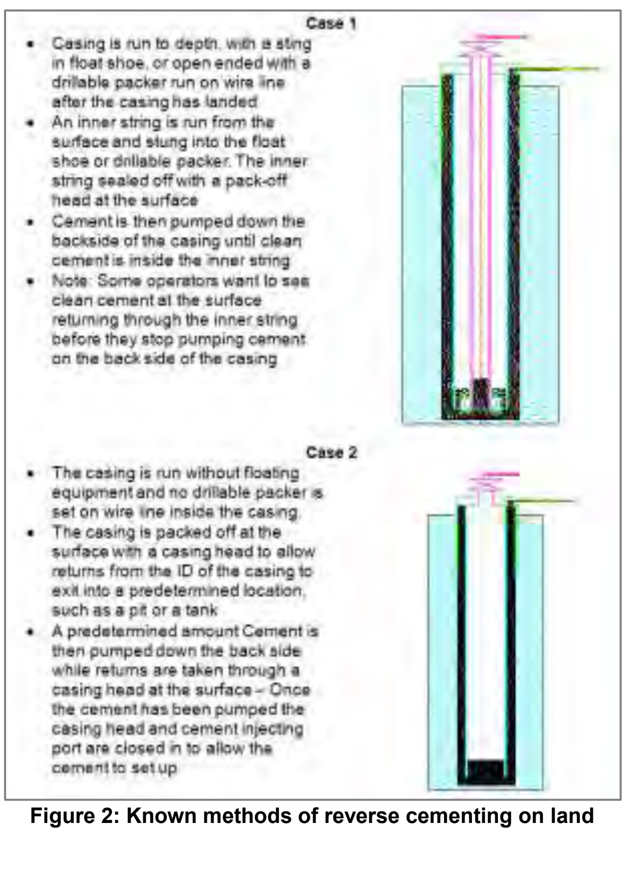

Figure 2: Known methods of reverse cementing on land

Numerous patents exist for various types of mechanical placement aids for reverse cementing. Two recent examples build on the method discussed in the first paragraph. One such patent (Badalamenti, et al., 2009) covers various methods of stopping the cement from the reverse side from entering excessively into the casing ID after the cement has reached the shoe joint (bottom) of the casing. Another patent (Chase, et al., 2012) covers the method of pumping out a standard float valve if the decision is made not to cement in the conventional direction. This method allows the operator to select the cementing method, conventional or reverse, most appropriate for the particular well situation, even after the casing has been run in the well.

To perform reverse cementing of liners in a reverse mode it is necessary to have a "crossover" tool system near the top of the liner, or above the portion of the liner that is to be reverse cemented. The crossover tool allows fluid pumped down the work string to crossover to the annular area of the liner casing OD and the hole ID, with returns from the ID of the liner casing moving through the crossover to exit into the annular area between the work string OD and the previously run casing ID. A pack-off between the port(s) allows fluid pumped down the work string to travel to the annulus side of the casing and the ports that allow the fluid from the liner casing ID to exit in the annular area between the work string OD and the previously run casing ID. Figure 3 shows a schematic of a crossover tool.

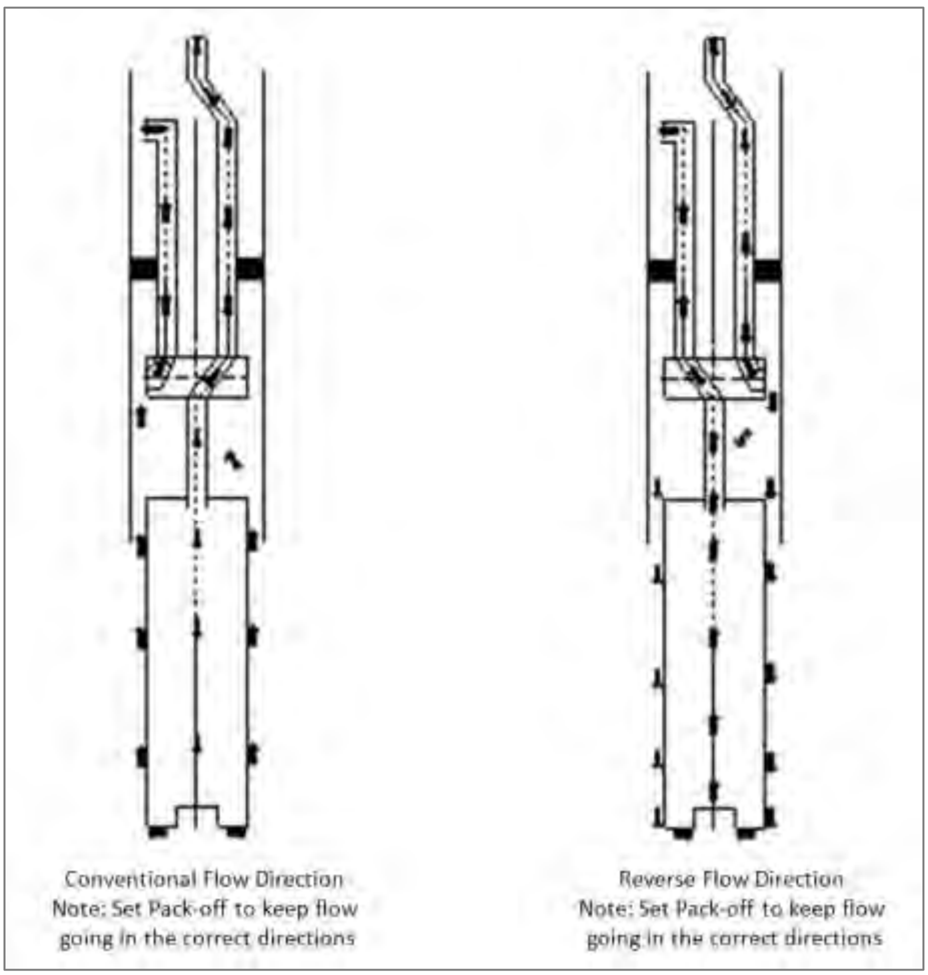

Figure 3: Switchable crossover is run at the top of the casing

One method is the use of existing gravel pack equipment above the top of the liner. A second method is the use of a switchable port collar above the portion of the liner that is to be reverse-cemented.

The gravel pack crossover allows conventional pumping down the work string into the ID of the liner and back up the annular area between the OD of the casing and the ID of the open hole. During the process of switching the crossover, the packer is set hydraulically in the ID of the previously run casing, and then the crossover shifts to allow all fluid displaced down the work sting to exit below the pack off to the annular area between the OD of the casing, with the returns coming back-up the ID of the liner. At the crossover the returns from the liner ID exit above the set pack off into the annular area between the work string OD and the previously run casing ID. The currently available gravel pack crossovers can only be switched once, and the pack off is typically a packer that is not intended to be unset at the conclusion of the job. The hydraulic set liner hanger, if used, with a gravel pack crossover tool would need to be set prior to switching flow from conventional to reverse flow. The reason for this is that the conventional flow direction normally used to hydraulically set the liner hanger will not be available after the flow is switched. That path will be blocked with a ball or dart that is used to switch the flow direction. Also, the method used to make the work string a closed chamber system to set the liner hanger hydraulically will need to re-open and not block reverse flow coming up the ID of the liner during the reverse cementing operation.

Use of a port collar for reverse cementing is described extensively in a patent by Giroux and Rosenberg (2010). If the port collar is to be used below the liner hanger, the liner hanger must be set and packed off to force all fluid pumped down the work string to travel down the annular area between the liner casing OD and the hole ID. The port collar can be opened and closed on demand to keep the cement in the casing annulus while the tools are being pulled out of the hole. The system would need modification for setting of the liner hanger and pumping fluid in the conventional direction prior to setting the liner hanger. The system also leaves a stage tool just below the liner hanger with ports that are typically sealed with elastomers, and an internal sleeve that may have collapse resistance less than that of the casing.

Requirements and Desires for Reverse Circulation Equipment in Deepwater. Casing strings in a deepwater application are typically run in the well on a work string such as drill pipe. In keeping with this scenario, the casing strings can be treated as liners.

When considering liner reverse cementing the following requirements and desires have been expressed by various operators:

1. Capablity of going in the hole with the work string un-obstructed through to the liner casing ID to allow the dropping of balls and pumping of darts if desired. Also to allow free conventional circulation while going in the hole. (Requirement)
2. Ability to move the pipe, reciprocate and/or rotate, while the pipe is going in the hole and once the pipe is on bottom (Requirement) – would also like to move the pipe while reverse cementing. (Desire)
3. Ability to set the liner hanger after the cement has been placed. (Requirement)
4. Ability to pump cement from the top of the liner to the annular area between the liner casing OD and the hole ID while taking returns up the liner ID – cementing ports below the liner hanger are not acceptable when considering potential leaks and collapse resistance below the liner hanger. (Requirement)
5. Ability to ream the liner in the hole while pumping in the reverse mode. (Desire)
6. Ability to place various fluids, e.g., cement, by circulation down the work string and back up the annular area between the work string and previously run casing ID without using the annular area between the liner OD and the hole ID as part of the circulation path. This keeps the weak formations behind the liner from having to be exposed to excessive pressures prior to placing the cement. If this is to be done the pipe must be moved during the circulation period, e.g., rotation during the circulation period to keep the fluid in the liner annular area from gelling. (Desire)
7. Ability to keep the pipe in motion, e.g., rotating, during the entire time the liner is being placed and cemented – shut down only when the liner hanger is being set. (Desired) (Note: This means the operator does not want to shut down to install a cementing head in the work string, nor stop to hook up lines to a pre-installed cementing head just below the top drive. Therefore all fluids pumped, including cement, will be done through the top drive. It also means that fluid separation with mechanical devices, e.g., balls and darts, typically dropped through plug containers may no longer be feasible. It also means looking at different ways of setting the liner hanger hydraulically other than by dropping a ball or dart to close the bottom of the work string and pressuring up to set the liner hanger.)
8. Keeping ECD (equivalent circulation density) to a minimum when placing cement is paramount. That is the main reason to consider reverse cementing. (Requirement) (Note: When looking at this requirement the use of any restriction at the bottom of the casing such as a float shoe and/or float collar during reverse cementing tends to give operators pause because the opening in the floating equipment may be less than the nominal ID of the casing. The operators still want well control when running and cementing casing, but they do not want an ID

less than the nominal casing ID while cementing and reverse circulating.)

Needed Technology for Future Implementation of RCPC. Evaluation of mechanical placement controls has found that a major challenge will be the development of a switchable crossover between a conventional and reverse flow path, and the modification of float equipment. Also, with the application of RCPC it is anticipated that the design methodology of cementing fluids may be affected by changing the placement method.

Crossover. In looking at the switchable crossover at the top of the casing, and taking into consideration the requirements and desires of various operators, we get the following set of requirements:

1. Ability to wash/ream the casing to bottom with standard or reverse flow – note (1) reverse flow can be done by pumping down the riser with returns being taken up the liner ID and through the work string ID; (2) or it can be done with concentric drill pipe where the fluid is pumped down the outer annulus and returns are taken through the liner ID back up the inner ID of the drill pipe; (3) or it can be done by pumping down the work string with flow crossed over at the crossover tool and returns taken back up the liner ID until the flow is crossed over to the annular area above the crossover tool . Note that options 2 and 3 pre-suppose a traveling pack-off to keep the fluids separated.
2. Ability of maintaining rotation during washing/reaming in – once the hanger pack-off is set, rotation must stop – the crossover will stay attached to the casing until it is hung off.
3. Maintain a minimum ID to allow the dropping of balls and or darts through the tool(s) when in the conventional circulation mode
4. When used on a casing system that requires a liner hanger, the crossover as a minimum must allow conventional circulation while running in the hole, crossover to reverse cement, switch back to the conventional flow direction to set the liner hanger.

From a desirability stand point we would like to add a four position crossover tool system that can be switched on demand:

1. Conventional flow direction where all fluid pumped down the work string goes through the liner ID and back up the annular area between the liner OD and the previously run casing ID or open hole ID. This flow direction also allows fluid flow down the external annulus and back up the liner ID and the work string.
2. Reverse flow direction where all fluid pumped down the work string is directed to the annular area between the liner casing OD and hole/or previously run casing ID. All returns are taken up the ID of the liner and diverted to the annular area between the work string and previously run casing and riser ID.
3. Circulation mode where all fluid pumped down the work string is diverted at the tool(s) to the annular area between the working string OD and previously run casing and riser ID. No fluid enters the liner ID or the annular area between the liner casing and open hole ID.
4. Bullhead or Squeeze mode where all fluid pumped into the work string can be used to pressure up the work string to set the liner hanger and operate other tools in the system.

Note: The crossover should allow rotation in all positions. Rotation only needs to stop when the liner hanger is being set.

A simple ball drop operated crossover can be designed to meet the minimum requirements listed for the crossover tool, but adding the desires to the operation mode of the crossover that is strictly a ball and/or dart operated tool would be a major challenge.

To add the desires to the operating mode of the crossover tool system means that the tool system operating method(s) will need to be evaluated from a multiple discipline stand point. This includes the use of traditional operating systems such as balls and/or darts systems, the use of battery powered systems, surface powered systems (e.g., hydraulic and/or electrically power), stored energy systems such as springs – both mechanical and gas powered, or vacuum chamber powered systems that are activated by various methods such as dropped balls, pump down darts, RFID tags, wired drill pipe, a wire line plug in run from the surface, fiber optics, mud pulse, mud pressure pulse, timers, hydraulic lines run from the surface, concentric drill string with the outer annulus of the drill pipe used as a hydraulic fluid carrier, etc. have all been considered. The feasibility of each system or combination(s) of each system will need to be carefully evaluated.

Float Equipment. In looking at floating equipment several things can be listed:

1. The floating equipment must have the minimum ECD possible, e.g., as large a flow path as possible

2. The floating equipment must remain open while the cement is placed. If it closes prematurely then the reverse cement job could squeeze off, leaving cement in the work string, which would be difficult to dump or reverse out while still attached to the liner, before the liner hanger is set.
3. Floating equipment must not limit the options of what can be run on the bottom of the liner casing for reaming in the hole – particularly while reaming in while circulating in the reverse mode.
4. An inner string run inside the liner casing can be used to keep the floating equipment open and take returns back to the top of the liner during reverse cementing. Once the liner hanger is set the inner string can be moved up and let the float valve(s) close. Excess cement pumped into the ID of the inner string can be dumped on top of the float equipment by pumping in the conventional manner, or it can be reversed out by pumping down the riser. (Note: The friction of pumping up the inner string needs to be taken into account when considering ECDs.)
5. The float equipment can be run near the top of the liner and held open by a stinger (inner string)
6. All floating equipment run on reverse cementing applications should probably seal in both directions once it is closed – This prevents the circulation of fluids inside the ID of the liner or above the top of the liner, e.g. dumping or reversing out excessive cement from a inner string from adversely affecting the newly placed cement

From an operator's perspective the selection and placement of floating equipment for reverse cementing will be done on a well by well basis. The two key considerations are to minimize ECD's during cementing and well control.

Additional Considerations. When considering fluid separation during reverse cementing, conventional mechanical systems, e.g., balls, pump down darts, or plugs, pose a challenge in what to do with the items down hole. If the crossover tool uses pumped or dropped items, such as balls, darts, RFID tags, etc., then mechanical fluid separators would have to essentially separate the fluid(s), then "disappear" from the ID of the work string so as not to impend other dropped or pumped items used to operate the tools. This does not imply that the items used to separate fluid(s) cannot be used to operate the crossover tool, but timing and location in the fluid stream would be critical.

Another challenge is when the operator wants to keep the pipe in motion, e.g., rotating during the entire operation. Shutting down to install cementing "heads" and hooking up cementing lines is not acceptable. This would require that the head be installed below the top drive while running the liner in the hole, or not using a cement head and instead pumping all fluids, including the cement, through the top drive.

Fluid separation may need to be accomplished with "gel" plugs. Gel plugs would need to be developed to effectively separate fluids and "sweep" the work string of any residual coating left behind by previously run fluids, and the following gel plug must sweep any coating left by the fluid immediately in front of the gel plug. The gel plugs could also be used as a carrier of balls and/or RFID tags that could be pumped through the top drive that are injected into the flow stream before the going through the top drive.

It has been suggested that foam plugs similar to ones used on pipelines can be launched in the flow stream prior to going through the top drive, effectively wiping the pipe ID. However, the issue of handling foam plugs down hole presents the same problem as other mechanical fluid separators: namely, what do you do with them once they have completed their wiping function?

It should be noted that the handling of the mechanical fluid separators presupposes the use of dropped objects to operate the down hole tools. If the tools can be operated with wired drill pipe (assuming that the wire does not restrict the ID of the drill pipe), hydraulic lines run on the OD of the pipe from the surface, concentric drill pipe with the outer annulus to hold hydraulic operating fluid, mud pulse, and/or mud pressure pulse then running a ball and/or dart catcher that will work with the selected operating system in the work string could be used and the problem of what to do with the mechanical fluid separators is eliminated.

At this time the primary challenge from a design perspective is the crossover tool system, with the second being the separation of the fluids without losing the ability to drop and/or pump objects down hole to operate tools. The floating equipment if used at the top of the liner already exists, and only minor modifications will need to be done to make it functional for reverse cementing. However, bottom of the string floating equipment that does not restrict flow and will close when necessary represents a major challenge and may need to be addressed in the second generation of this equipment.

Simulations and Modeling.

Commercial Software Limitations and Alternative. Predicting down-hole temperatures and pressures during cementing is a well-researched and common technique that many software packages handle. However, these packages are designed for conventional cementing and are unable to incorporate the configuration used in these reverse circulation systems. It was therefore necessary to develop an alternative method to model these specific systems. A finite-element analysis (FEA) model was developed to this end. Development of this approach does require the developer to manually translate the problem into a mathematical formulation. While the governing equations, namely the heat equation with convection and the Navier-Stokes equations, are well-studied, they require careful manipulation for this specific system.

In its current form, the model developed is two-dimensional, and has temperature as a function of radial position as well as depth. This is an improvement over many conventional simulators, whichare one dimensional, and have temperature as a function of depth only. One-dimensional models are known to oversimplify the heat transfer process in conventional wells (Bittleston 1990), and are therefore even more unsuitable for RCPC wells which require a better treatment of the annular temperature.

Finite Element Modeling of Deepwater RCPC.

Geometry and Scaling. The well is divided horizontally into regions of constant outer-hole diameter, with each region representing either a specific string or the riser. Each of these horizontal regions is then vertically subdivided into four domains. In the regions below the mudline, the regions represent the drillpipe, the drillpipe wall, the annular space, and the rock formation. In the riser region, the outermost region (i.e., the rock formation in the other regions) is replaced with the riser outer wall. This is demonstrated in Figure 4.

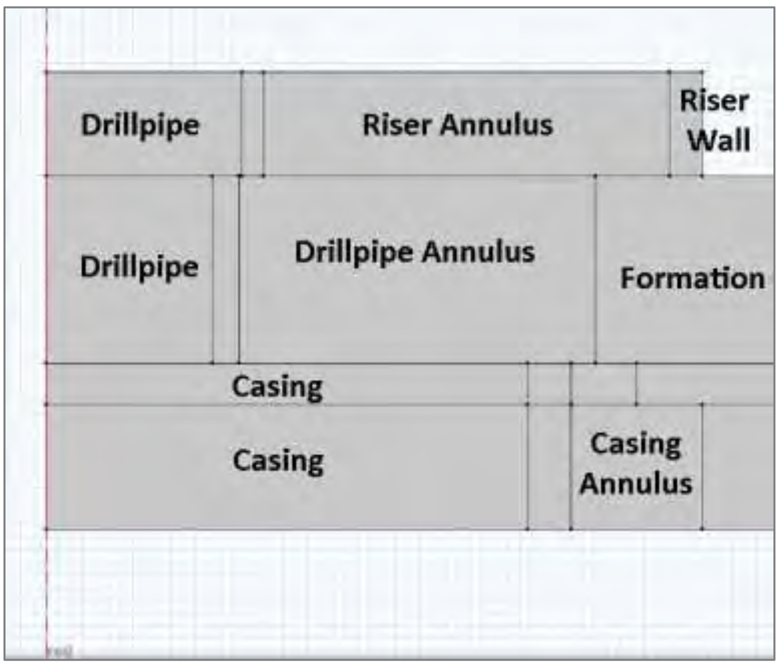

Figure 4. Simplified well geometry for FEA

Typical well systems have a very large aspect ratio ($\approx 1{:}\,10^5$), which causes the generated meshes to be of very poor quality, and to result in significant numerical errors. In order to overcome this difficulty, the geometry of the system and the governing equations were rescaled so that the aspect ratio is $1{:}\,1$.

Rescaled Equations. Following the basic approach of Bittleston (1990), but changing his variables to match traditional dimensionless groups, the heat equation is rescaled and non-dimensionalized into the following form:

$$\frac{\partial\theta}{\partial t^*} + v_z^* \frac{\partial\theta}{\partial z^*} = \frac{1}{\Psi Pe} \nabla_r^{\,2}\theta \qquad (1)$$

The dimensionless groups are defined as:

$$r^* = \frac{r}{r_{\max}} \quad (2)$$

$$z^* = \frac{z}{z_{\max}} \quad (3)$$

$$Pe = \frac{r_{max} v_{in}}{\alpha} \quad (4)$$

$$\theta = \frac{T - T_{ML}}{T_{BH} - T_{ML}} \quad (5)$$

$$t^* = \frac{v_{in}}{z_{\max}} t \quad (6)$$

$$\psi = \frac{r_{\max}}{z_{\max}} \quad (7)$$

Where T_{ML} is the geothermal temperature at the mudline, T_{BH} is the geothermal temperature at the bottom of the well, and v_{in} is the fluid velocity in the riser. Negligible terms (convection in the radial direction and conduction in the vertical direction) have been discarded. This is very similar to the usual form of the dimensionless heat equation (Bird et al., 2006), but with the additional the scaling term, Ψ .

The Navier-Stokes equations were rescaled in a similar fashion as:

$$\left(\frac{\partial v_z}{\partial t^*}\right) = -\frac{dp^*}{dz^*} + \frac{1}{\psi Re_B} \nabla_r \left(\mu^* \nabla_r v_z\right) \quad (8)$$

Where the new dimensionless groups are

$$\mathrm{Re}_B = \frac{\rho v_{in} r_{\max}}{\mu_\infty} \quad (9)$$

$$p^* = \frac{p + \rho g z}{p_o} \quad (10)$$

$$p_o = \frac{\mu_\infty v_{in}}{r_{\max}} \quad (11)$$

Again, this is similar to the usual non-dimensionalization of the Navier-Stokes equations (Bird et al., 2006) but with the addition of the scaling term, Ψ .

Viscosity. The viscosity term, μ^* , requires additional discussion. The drilling fluids are modeled as Bingham fluids (Deen 1998):

$$\mu_e = \begin{cases} \mu_\infty + \dfrac{\tau_y}{\dot{\gamma}} & \tau > \tau_y \\ \infty & \tau \le \tau_y \end{cases} \tag{12}$$

In dimensionless form, this becomes

$$\mu_e^* = \begin{cases} 1 + \dfrac{r_{\max}\tau_y^*}{\mu_\infty v_{in}\dot{\gamma}^*} & \tau^* > \tau_y^* \\ \infty & \tau^* \le \tau_y^* \end{cases} \tag{13}$$

The difficulty created by the above equation in solving this system numerically is the introduction of discontinuity (Gjerstad et al., 2013). The finite-element software used does not have built-in support for Bingham fluids. It was therefore necessary to approximate this model with the Carreau model, which is continuous and finite everywhere:

$$\mu_e^* = \mu_{inf} + (\mu_0 - \mu_{inf})\left(1 + (\lambda\dot{\gamma})^2\right)^{\frac{n-1}{2}} \tag{14}$$

The four model parameters are then used to fit this model to the Bingham model, using standard nonlinear regression. This approach generates accurate velocity profiles, which are needed for the convective term in the heat equation.

Boundary Conditions. The boundary conditions for the Navier-Stokes equations are straightforward. At the walls, the velocity is zero. At the inflow and outflow boundaries (e.g. the top and bottom of the riser) the flow is forced to be laminar. For the pressure, only one boundary condition is required, and so the outflow pressure is set to zero in each region.

The heat equation has two modes of heat transport: convection and conduction. Conduction is limited to the radial position, and therefore through the vertical boundaries (e.g., the drillpipe walls). Convection is limited to the vertical direction, and therefore through the horizontal boundaries (e.g., the drillpipe top). It is convenient to divide the boundary conditions into the same classifications.

For the convective boundary conditions, there are only two different scenarios: inlet flow and outlet flow. The outflow condition is formulated with the assumption that heat conduction is negligible, and is therefore mathematically identical to an adiabatic surface:

$$\vec{n} \cdot \vec{\nabla} T = 0 \tag{15}$$

Where $\vec{n}$ is the external normal vector to the boundary. The inlets are set to a specific temperature. At the riser surface is the inlet temperature of the fluids. The inlets of each region in the well are set to the mixing-cup temperature, $\left(T_{mc}\right)$, at the preceding region's outlet, namely:

$$T_{mc} = \frac{\int_{A_c} u_z T}{\int_{A_c} u_z} \tag{16}$$

This conserves energy through the well. With the exception of the specified geothermal temperature profile, the conductive boundary conditions are handled automatically by the softwareand assume the continuity of flux and temperature across the boundary. This is the same boundary condition used by Bittleston (1990) in his model for conventional circulation.

$$T_{left} = T_{right} \tag{17}$$

$$k_{left} \frac{\partial T}{\partial r}\bigg|_{left} = k_{right} \frac{\partial T}{\partial r}\bigg|_{right} \tag{18}$$

At an infinite distance from the well, the geothermal temperature profile is assumed to be undisturbed.

$$T(r,z)\big|_{r=\infty} = T_{geothermal}(z) \tag{19}$$

In a numerical solution, an infinite distance is impossible to implement, so a very large distance was used instead.

Time-Stepping. The finite-element scheme was solved with fully implicit methods. The time-stepping was accomplished with a backward differentiation formula (BDF). When using BDF methods of orders higher than one, unphysical oscillations can be generated, which is exactly what was observed. It was therefore necessary to limit the method to first-order BDF.

Pressure Modeling of Deepwater RCPC. In order to maintain consistency with the conventional models (Diaz et al., 2004), a model based on analytical results, rather than on a finite-element formulation, was developed to predict downhole pressures and ECDs. In this model, the pressure is the sum of two different terms: the pressure due to friction and the pressure due to static forces (Diaz et al., 2004).

$$P = \Delta P_{friction} + \Delta P_{static} \tag{20}$$

$$\Delta P_{static} = \rho g h \tag{21}$$

The frictional pressure drop has no universal formula, but it is a function of the flow rate, physical properties of the fluid, the flow regime, and the geometric configuration of the system. There are a large number of correlations and analytical results which have been developed for specific geometric configurations and viscosity models. All of the fluids are Bingham, the flow regimes are laminar and there are two different geometries: circular pipes, and concentric annuli.

Pipe Flow. The basis for calculating the pressure drop of a Bingham fluid in pipe flow is the Buckingham-Reiner equation (Chhabra and Richardson, 2008) which calculates the friction factor:

$$f = \frac{16}{\mathrm{Re}_B}\left[1 + \frac{He}{6Re_B} - \frac{1}{3}\left(\frac{He^4}{f^3\,\mathrm{Re}_B{}^7}\right)\right] \tag{22}$$

where He is the Hedstrom number.

$$He = \frac{\rho D^2 \tau_y}{\mu_\infty{}^2} \tag{23}$$

The total pressure drop can then be calculated directly as:

$$\frac{-\Delta P_{friction}}{L} = \frac{2 f \rho V_{sup}{}^2}{D} \tag{24}$$

Flow in Concentric Annuli. The formulation developed by Fredrickson and Bird (1958) to determine the pressure drop for Bingham fluids in annuli requires solving three simultaneous equations. The pressure drop per unit length is ΔP_L, κ is the ratio of the outer to inner diameter, R is the outer radius, and Q is the flow rate, expressed as

$$Q = \frac{\pi R^4 \Delta P_L}{8\mu_\infty} \begin{bmatrix} \left(1-\kappa^4\right) - 2\lambda\left(\lambda - T_0\right)\left(1-\kappa^2\right) \\ -\frac{4}{3}\left(1+\kappa^3\right)T_0 + \frac{1}{3}\left(2\lambda - T_0\right)^3 T_0 \end{bmatrix} \quad (25)$$

where λ, T_0, are unknown parameters to be determined along with ΔP_L, based on the following equations.

$$T_0 = \frac{2\tau_y}{R\Delta P_L} \quad (26)$$

$$2\lambda\left(\lambda - T_0\right)\ln\left(\frac{\lambda - T_0}{\lambda\kappa}\right) - 1 + \left(T_0 + \kappa\right)^2 + 2T_0\left(1-\lambda\right) = 0 \quad (27)$$

Once all of the pressure drops are calculated, the total pressure in the well can be pieced together, and then converted to ECD as

$$\rho_{equiv} = \frac{\Delta P}{gh} \quad (25)$$

Modeling and Simulation Results.

Conventional-Circulation Temperature. In order to verify the model, a conventional cement placement job was analyzed and compared to results from a commercial simulator. Two points of comparison were done between the simulator model and the FEA model: Bottom-Hole Circulating Temperatures (BHCTs) and First-Sack Last-Sack Temperatures. Figure 5 demonstrates the high level of correlation between the FEA model and the simulator, after the initial cooling-off period.

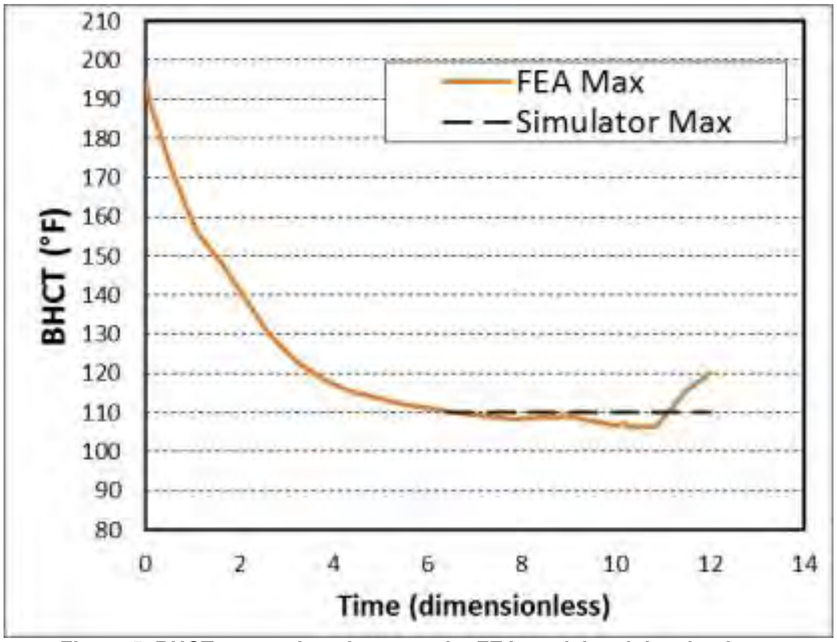

Figure 5. BHCT comparison between the FEA model and the simulator.

While BHCTs are an important parameter in describing the temperature of the well (Shell and Tragessert, 1972), the actual temperature that the cement experiences is a more important parameter for slurry design. Figure 6 compares the temperature in the cement from the FEA model to the First Sack-Last Sack temperatures from the simulator. Again, a high level of agreement is found between the FEA model and the simulator. Based on these results, the FEA model was judged to be accurate and robust.

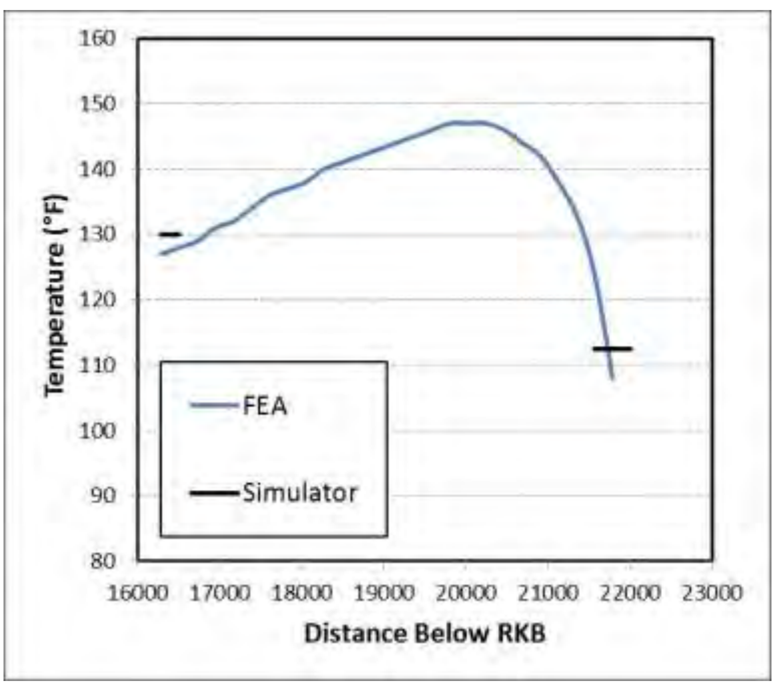

Figure 6. Temperature in the Cement and the end of the placement process

Reverse-Circulation Temperature. A FEA simulation of reverse placement was performed and the results analyzed in a similar fashion to the conventional simulation. Figure 7 shows the BHCT as a function of time during the reverse placement process. It includes both the mixing cup average and the maximum. The BHCT is significantly higher for reverse flow than it is in conventional flow. In this example, the maximum in reverse flow is approximately 50 °F higher than in conventional flow. This is not unsurprising, because the source of heat to the system is the surrounding rock formation, and consequently as the fluid travels in reverse circulation down the annulus it absorbs much more heat than in conventional circulation.

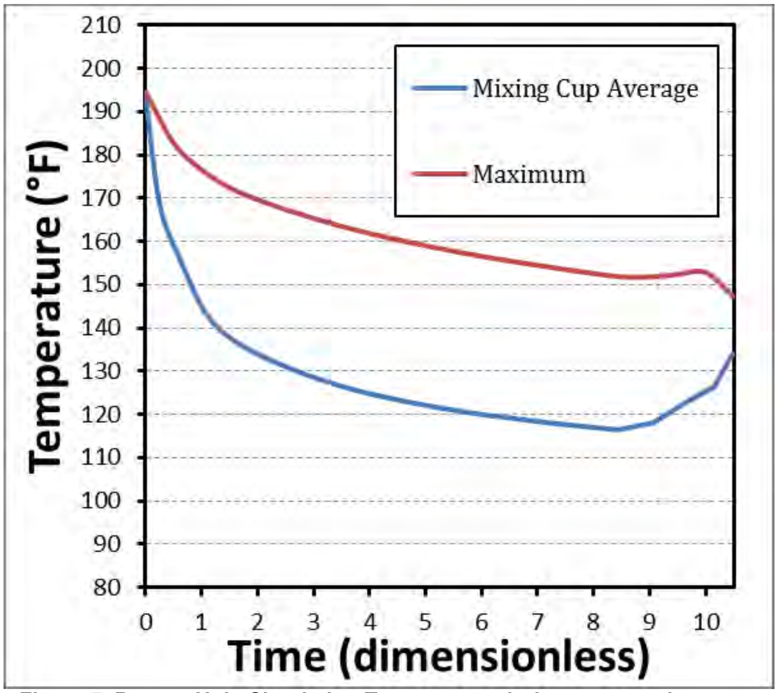

Figure 7. Bottom Hole Circulating Temperature during reverse placement

However, in reverse placement the bulk of cement slurry never passes through the bottom of the well and does not experience the full bottom-hole temperature. Therefore, the first-sack last-sack temperatures are even more important in reverse placement. The cement temperatures are shown in Figure 8.

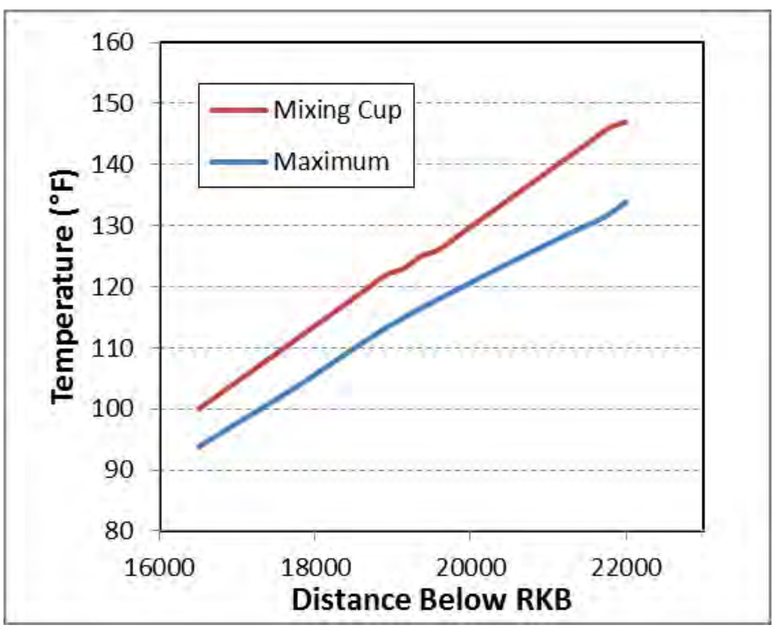

Figure 8. Temperature in the cement at the end of reverse placement.

The slurry temperatures are almost linear and do not have a maximum between the first-sack and last-sack experienced like in conventional placement. This is due to the fact that the flow is aligned with the geothermal temperature gradient. When compared to the results for conventional circulation, the slurry temperatures are not significantly higher than for conventional placement. This is not the conclusion to which the BHCT would have led, and it illustrates the relative importance of first-sack last-sack temperatures in reverse placement.

Pressures and Equivalent Circulating Densities. The goal of reverse placement is to reduce ECDs. Following the procedure detailed above, ECDs were calculated for both conventional and reverse placement. The results of the study are presented in Table 1. The results demonstrate that reverse placement is effective at reducing ECDs at both the current and previous shoe.

Table 1. Equivalent Circulating Densities in Conventional and Reverse Placement at the end of cement placement

		ECDs(ppg)		
		Conventional	Reverse	Change
Region 1	Current Shoe	14.170	12.545	-11%
	Previous Shoe	13.184	12.550	-5%
Region 2	Current Shoe	14.238	13.039	-8%
	Previous Shoe	13.243	12.574	-5%
Region 3	Current Shoe	13.435	12.794	-5%
	Previous Shoe	13.047	12.627	-3%

Considerations for Cementing Fluids.

Additive Staging. Advantageous modification of cement designs can be made with the application of RCPC. Previous literature has cited many cases where additives have been staged with reverse placement to both optimize and reduce WOC time. As shown by preliminary simulation work, fluids are exposed to different temperatures compared to conventional placement due to the placement method. This reverse simulation assumes that the reverse fluid tempature profile is the same as conventional until the crossover tool is reached, then heat transfer is increased as the fluid travels down the annulus resulting in a BHCT equal to or greater than those simulated for conventional placement. Temperature simulations comparing conventional and estimated reverse first and last sack temperatures for a generic deepwater 16inch liner string set at 22,000 feet MD are shown in Figure 9. During conventional placement the bulk of the slurry is exposed to the BHCT as it rounds the shoe and continues up into the annulus. This temperature profile requires that the first sack contain enough retarding additive to ensure adequate placement time, plus a factor of safety. When large volumes of cement are placed, the amount of retarder can delay compressive strength development at the top of cement for days, especially when there is greater temperature variance between the shoe and top of cement. In reverse placement only the leading sacks of cement will see the BHCT; only this volume will need to have the largest dose of retarder. The retarder can then be reduced in the following sacks so that the entire column of slurry develops compressive strength at approximately the same time. Another consideration for deepwater will be gel strength development of the column if staged slurries are used to ensure that gas migration risk is reduced.

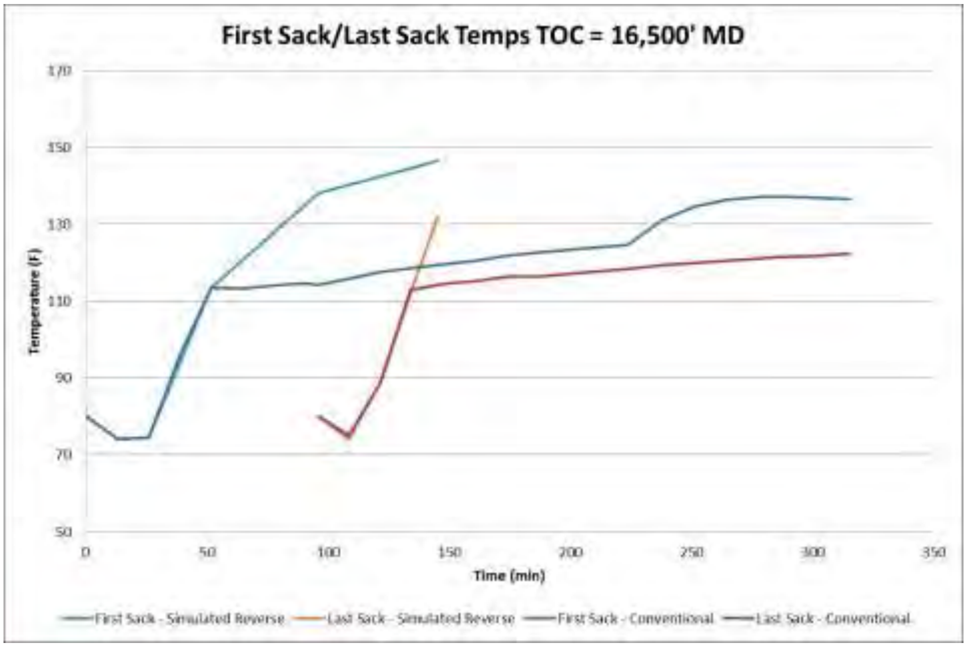

Figure 9: Comparison of simulated reverse and conventional 16" liner temperatures during placement

Reducing Placement Time. Previous onshore jobs and preliminary simulations have shown that placement time can be reduced with RCPC; the inner casing or liner volume no longer needs to be displaced, and the displacement volume is reduced to the workstring volume plus any annular volume above the top of cement (TOC). In the example shown in Figure 10 the reverse crossover was located at 14,000 feet MD, and placement time was reduced by about half during reverse placement. Figure 10 shows example thickening times for reverse and conventional slurries for a 16-inch liner set at 14,000 feet MD, with the crossover tool located at 5,500 feet MD. Using reverse placement on this string reduces the required thicking time by about 5 hours, and reduces the amount of retarding addtivie needed for placement.

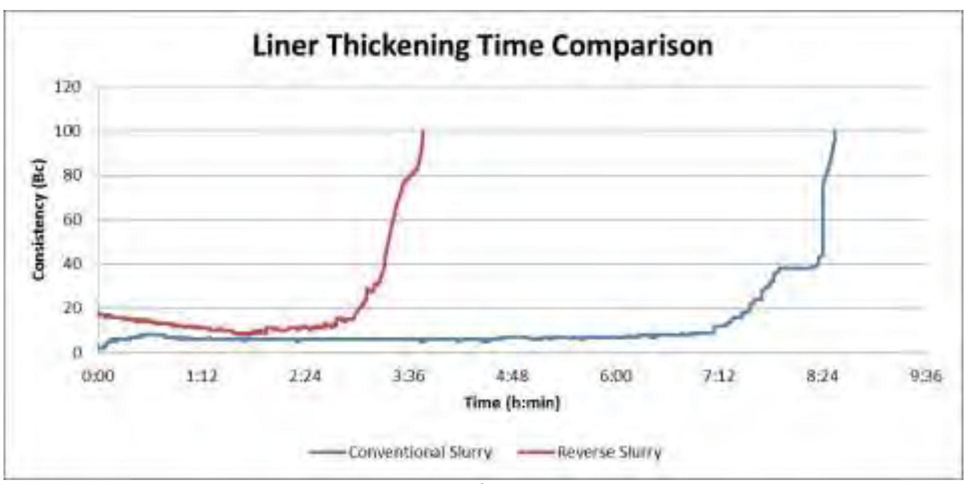

Figure 10: Thickening time of a 16" liner slurry, 14,000' MD

Figure 11 shows the reverse and conventional thickening times for an 11-7/8 inch liner slurry where the reverse crossover is located at 20,500 feet MD. In this string, RCPC reduces required thickening time by about 1 hour. Overall, initial results indicate that difference in placement time will depend on crossover location, length of workstring above the crossover, and volume of slurry.

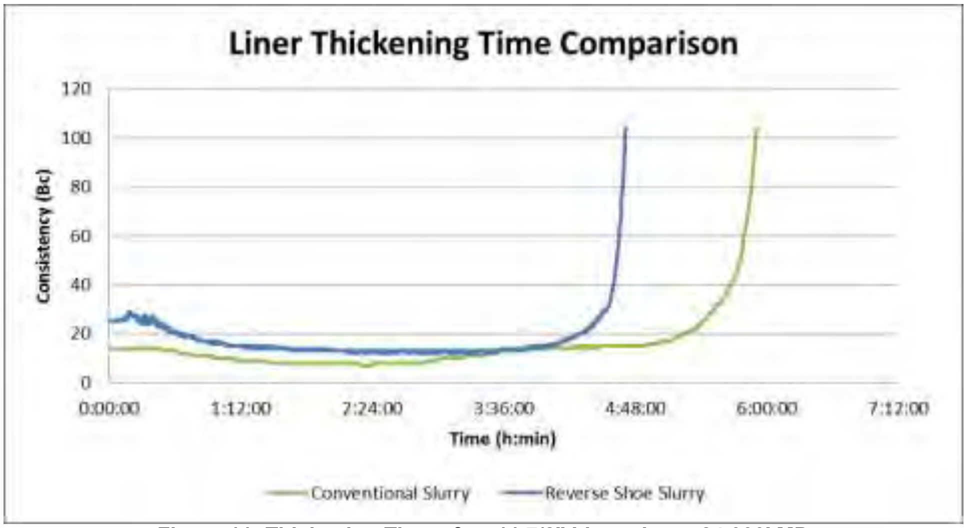

Figure 11: Thickening Time of an 11 7/8" Liner slurry, 24,000' MD

Design Considerations. In conventional cementing, a fluid hierarchy of rheology and density is used to assist fluid displacement. Displacement efficiency with flow rate through both the drill pipe and annulus are also taken into consideration. The prevention of fluid intermixing is expected to increase in importance with reverse placement since fluid separation cannot be aided by mechanical means such as plugs and darts. Initial fluid investigations on the effect of reverse circulation placement on design by density and rheological hierarchy were conducted through small-scale simulations. Fluid design parameters for RCPC will be influenced by the change in placement method since flow in the annulus is assisted by gravity.

In RCPC, the order of fluids pumped downhole will change when two slurry systems are used, such as a lead and tail slurry in conventional placement. In reverse placement, the first sacks of slurry pumped will be the equivalent of the conventional tail to cover the critical zone at the shoe, which will be followed by the 'lead'. Conventionally, the tail slurry is generally of a higher density and higher viscosity fluid than the lead. Preliminary laboratory intermixing studies have shown that following conventional design hierarchy for rheology and density can lead to interface instability between the shoe slurry and a following conventional lead when pumped in a reverse placement scenario. Small-scale laboratory simulations have shown that conventional density hierarch can be maintained with RCPC as long as the rheological hierarchy increases in the order the fluids are pumped downhole; a less viscous dense shoe slurry can be displaced by a lighter 'lead' in the annulus as long as the lead is more viscous to aid displacement. Since the role of density hierarchy can be reduced with RCPC, designs can be further modified so that equal density fluids (mud, spacer, and slurry) are pumped downhole as long as each subsequent fluid is increasing in rheology, which could bring additional ECD benefits. Pre-job validation through simulations is still needed to ensure that pressures remain in the pore-frac window during pumping.

Spacers and Fluid Separation. The lack of conventional mechanical separation means that mud removal and fluid separation will remain a major challenge in the application of RCPC in deepwater. The leading edge of cement will become the shoe slurry, so it is especially critical that this area avoid contamination. Poor casing standoff and incomplete mud removal can result in costly remedial work. Since mechanical plugs cannot be used in reverse placement, viscous pills can be used in conjunction with a spacer to aid in mud removal and separation. In addition, spacer volumes may need to be increased, as determined through mud removal simulations. To replace the conventional top plug, a viscous pill and spacer will need to be pumped after cement for displacement to prevent mud contamination on the tail end. Operationally, over-displacement into the casing may be an option to ensure quality cement in the shoe; time to drill out the extra cement will be less costly than remedial work. However, displacement efficiency is still critical, even with over-displacement.

Conclusions

Some existing technology can be modified for use for deepwater RCPC; however, some areas require advancement:

- Since modeling plays such an extensive role in determining feasibility, simulations specifically for deepwater RCPC is a critical technology development area. Preliminary results with the developed FEA model have shown ECD reduction with RCPC, compared to conventional placement. As tool configurations and fluid designs are developed this model can contine to be refined.

- Another critical development area is mechanical tools, primarily a switichable crossover that will divert the flow back and forth between the workstring and annulus and float equipment to control flowback. Exisitng technology can be modified for RCPC float equipment positioned close to the crossover tool or liner hanger; however development is needed for float equipment placed at the shoe.
- Once the simulations and tool technology is in place, fluid design can be tailored so that further advantages such as reducting additives and operational time of RCPC in deepwater. Since the downhole fluid temperature profile and placement times are not expected to be the same as those seen during conventional placement, effects of these deepwater RCPC designs will need to take these variations and their effect during and after placement into consideration.
- Other areas that need to be considered as this technology continues to develop are the identification of cement downhole and the impact on operational plans.

Overall RCPC viability will be dependent on proving and quantifiying the ECD reduction before this technology can be implemented in the field. Modeling and simulations will be crucital for determining the extent of ECD reduction, if any. These simulations need to be made available to the industry either through modifications of existing commericial software or by continued development of a custom deepwater RCPC model, such as the FEA model introduced in this paper. Prelininary investigations have shown that the application of RCPC to deepwater cementing has the potential to reduce ECDs during job placement. ECD reduction would be advantageous in the narrow pore-frac gradient commonly seen in deepwater formations and would bring benefits such as reducing lost circulation risk, improving zonal isolation and increasing TOC.

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Nomenclature

BDF	=	Backward differentiation formula
BOP	=	Blow out preventer
bpm	=	Barrels per minute
ECD	=	Equivalent Circulating Density
FEA	=	Finite Element Analysis
HHP	=	Hydraulic Horse Power
HTHP	=	High Temperature High Pressure
ID	=	Inner Diameter
OD	=	Outter Diameter
ppg	=	Pounds per gallon

RCPC = Reverse-Circulation Primary Cementing

RFID = Radio-Frequency Identification

TOC = Top of cement

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