



Deepwater Cementing Best Practices for the Riserless Section

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Abstract

Exploration for oil and gas in deep water offers unique challenges in well construction, beginning at the seafloor. Large-bore, subsea wellhead designs required to reach directional targets at depths in excess of 30,000 ft RKB (rotary kelly bushing) require competent cement placement to maximize casing support and isolation for drilling operations.

Routine challenges associated with the riserless section (also referred to as the tophole section) are low fracture gradients resulting from young, unconsolidated sands and shallow drilling hazards such as shallow water flows (SWF) or hydrate formations. Although not encountered on every location, these specific areas referenced as shallow hazards require planning the wellhead casing and drilling designs specially to help prevent initiation of flow before running and cementing of casing strings. Specialized, low-density cementing systems are used for maintaining satisfactory equivalent circulating density (ECD) for cement returns back to the seabed. These low-density systems can be prepared either by an engineered foaming operation or by the use of specialized additives blended with cement to lower the slurry density. Bottomhole circulating temperature (BHCT) is calculated using a thermal simulator; slurries are designed using special laboratory testing equipment to help accurately define the additives necessary for optimal results. Mechanical aids to place the slurries effectively are used with many different landing strings to run the large-diameter casing.

As more offset wells are completed with flow lines connected back to production platforms, the overall effectiveness of drilling the riserless section with minimal disturbance to surrounding seafloor becomes critical. Lack of cement returns may compromise the casing support and excess cement returns cause problems with flow lines and control lines. Calipers used to accurately estimate hole volumes are available for these large hole sizes but are seldom used; therefore, use of tracers and other methods have provided the best approach to accurate determination of cement returns to the seafloor. Many different methods of early detection of cement returns have been used with varying degrees of success.

This paper (1) presents, in a "best practices" style, some published processes and procedures used to

successfully cement the riserless sections; and (2) incorporates new methods for monitoring cement returns and placement into many challenging areas of deepwater exploration.

Introduction

Design of a cementing operation for the first casing strings (structural and conductor) of a deepwater drilling project encompasses many techniques that are critical to job success. For instance, if the designer knows the pore pressure/fracture gradient, he can formulate a low-density cementing design. This low-density slurry is calculated to return back to the seafloor to provide wellhead support and isolate interzonal communication behind the casing. Dynamically placed drilling fluids are located in the wellbore before casing is run in and cemented for the control of any SWF's that may be induced during the drilling operation.

It is very important to note that if a SWF is anticipated, the key to control throughout the riserless drilling section is to prohibit the early inducement of flow by maintaining a hydrostatic pressure column adequate to exceed the formation pore pressure.^{1,2} **Fig. 1** provides an example of a seismic interpretation of a SWF event in the Gulf of Mexico. Likewise, the cementing formulation also has to exhibit fluid density properties adequate to maintain overbalance but stay within the narrow margin of fracture gradient associated with these young formations. Because all associated drilling fluids and cementing fluids will return back to the seafloor, a spacer formulation with tracers is prepared to identify early seafloor returns. The returns are intended to minimize mound buildup around the wellhead template, yet help ensure that good cement has returned back to the mudline. **Fig. 2** is an example of how buildup around the wellhead can be observed during the riserless drilling sections.

Riserless cementing consists of all fluids conveyed through a drillpipe assembly of a landing string and inner-string stinger used to land the casing and release to the wellhead. Because no drillpipe wiper darts are pumped behind the cement slurry, determining exact capacities for positive cement placement is critical. Adequate shoe track length with competent cement is necessary for performing the casing test before drillout.

A “best practices” approach to optimized cementing results of the riserless section is addressed in the subsequent sections. Particular attention is placed on temperature determination for cementing, tools used to effectively place uncontaminated slurry, slurry designs for control of SWF, and an effective means for accurate determination of seafloor returns for mitigation of excessive mound buildup.

Shallow Water Flow Prevention

Water flows (SWF) from over-pressured saltwater sands located at fairly shallow depths below the mudline (BML) occur in the riserless drilling section. These flows are normally characterized by a narrow margin between pore pressure and fracture gradient.

Density control of downhole fluids during the drilling phase requires use of a variety of different fluids. Weighted mud systems, also referred to as cutback drilling fluids, are built and pumped “on the fly” during the drilling phase to help prevent influx of SWF. Spotting fluids, also referred to as kill muds or pad muds, are spotted in the hole before casing is run to help maintain hydrostatic pressure on the water-flow sand. Use of pad mud containing shear-sensitive biopolymers and low gel content produces low API fluid-loss fluids that can (1) enhance the displacement process to eliminate channels behind casing, and (2) reduce surge pressures during the running and cementing of riserless casing strings.¹

Finally, a competent cementing design is placed after the casing is landed. Maintaining circulation and obtaining cementing returns back to the seafloor is critical. In addition to maintaining circulation, it is critical to displace the mud from the annulus with a high-quality, uncontaminated cement slurry to (1) prevent inter-zonal communication and support the wellhead and blowout preventer (BOP) stack and (2) for subsequent loading of casing strings. Failure to recognize the potential existence of SWF and to design all fluids to control hydrostatic pressure can lead to severe consequences:

1. Flow after cementing can result in loss of support at the wellhead resulting in possible wellbore damage, or loss of the well.
2. Wells allowed to flow uncontrolled during the drilling phase can experience severe sand mining that cause large washouts. Washouts of the magnitude seen in SWF zone are impossible to cement properly and can lead to lost of a single well, several wells, or an entire template.²

Solving the challenge of cementing a deepwater well successfully depends upon the following controls:

- Assessing the shallow hazard risk, selecting the lowest risk drill site based on seismic work and offset wells and reservoir target³
- Using drilling techniques that control flow and lost circulation while drilling the riserless hole section¹
- Conditioning of drilling fluids, spotting fluids, and borehole before running the casing and cementing the annulus⁴
- Designing the proper slurry density to control formation influx without exceeding the fracture gradient
- Designing the proper slurry performance properties required to control flow and support the casing

Recognizing the importance of a well-engineered fluid system for drilling and cementing a high-risk SWF riserless section involves the use of unique cement designs that maintain the hydrostatic control throughout the transition setting period.⁵

Slurry Formulation and Testing. A cement slurry design formulated to provide good zonal isolation in a deepwater environment should have a unique set of properties to provide the necessary flow control and effectively displace the contents of a large annulus. While conventional lightweight cement slurries are not considered acceptable for cementing deepwater casings two types of high- performance slurries have been used successfully and are considered acceptable.

The first slurry type used successfully is non-foamed slurry composed of accelerated base cement extended with microspheres. Microsphere slurries have gained acceptance and have been applied successfully in deepwater non-SWF applications offshore Brazil.⁶ High-strength, lightweight (HSLW) blends can provide excellent strength development at lower than normal slurry density and low temperature.

The second type is high-performance foamed cement systems, which have proven the most successful and have demonstrated special characteristics such as

- Variable low-density designs that allow changes caused by hole conditions or fracture-gradient considerations
- Short transition times for flow control and minimized hydrostatic losses (overbalance)
- Excellent compressive strength development at low temperatures
- Unique ability to displace mud and spacers as determined through large-scale testing associated with nitrified fluids
- Inherent low fluid loss associated with foam slurry designs

Offshore cementing requires that cement blends perform a wide range of downhole operations to help minimize the need for specialized bulk-blend formulations. Normally, if low-density slurries are required, there are several methods to obtain them.

1. Conventional water-extended slurries include an additive used to absorb additional water to reduce the density of the base slurry. Water-extended slurries usually have poor performance characteristics for the control of gel-strength development and compressive strength because they contain a high percentage of water. This method is not recommended, as found through the evolution of deepwater drilling in SWF areas.
2. Non-foamed, high-performance slurries use a specialized, low-density blend of cement and microspheres for control of SWF zones. These blends, although used successfully, offer a minimum variability in density should a design change be required. The blended lightweight slurries also require considerable additional bulk storage space aboard the rig, which is an issue that should be considered with the large slurry volumes required for the conductor casing.
3. Foamed cement designs, where applicable, offer several distinct advantages. Besides having all the performance characteristics necessary to control SWF's, foamed cement has a wide range of downhole density variability using the same base blend.⁷ In conjunction with capabilities of downhole simulation and design software, it is possible to design or redesign the low-density formulation onsite when well conditions change; e.g., changes in pore pressure or fracture gradient; without sacrificing performance.

Laboratory testing of the deepwater slurries requires specialized laboratory equipment to accurately simulate the environments that they are subjected to in a deepwater operation. The equipment must be capable of subjecting the slurry to temperatures and pressures expected from the surface to the downhole in the wellbore. Consistometers equipped with specialized chillers are required for testing thickening time as well as chillers for curing cement for compressive strength. **Fig. 3** shows a consistometer mounted with a chiller to perform testing as described.

Cement Volume Consideration. Determination of cement volumes required for seafloor returns may vary depending upon how the section has been drilled. In most drilling plans, an excess volume of 125 to 175 % is very common when care has been taken to eliminate any possibility of induced flow through the target section. It is also not unusual to increase excess by more than 200% if hole enlargement caused by poor flow control

during the drilling phase is observed. For most cases, having a planned excess volume of 150% will satisfy most operations with good cement returns to the seafloor.

Temperature Determination

Pressure is known to have a marked effect on cement setting behavior, but temperature is by far the strongest external factor affecting cement setting. Standard tables are unacceptable for determining the temperatures encountered in wells drilled in deepwater environments. The temperatures in the ocean and at the sea floor are much cooler than surface temperatures; thus, the cement is first exposed to an inverse temperature gradient as it is being circulated down the drillpipe. Additionally, the temperatures of the formations near the sea floor are very cool and must be accounted for in the design of slurry placement and curing. The conditions while mixing the cement on the surface can vary seasonally. For these reasons, the temperatures should be measured and/or modeled in simulators so that the appropriate temperature schedules can be computed and used when testing slurries for application in deepwater conditions.⁸

Two primary temperatures are required for successful cement placement and curing. Bottomhole circulating temperature (BHCT) is required for determining slurry total thickening time (TTT), and slurry curing temperature is used to determine the proper waiting on cement (WOC) time.

Bottomhole Circulating Temperatures (BHCTs).

When planning for cementing operations in the deepwater offshore environment, one of the main design considerations is the water depth and resulting temperature profile. API cementing tables and procedures currently available do not address the temperature needs associated with deepwater and ultra-deepwater cementing. The resulting practice has been to use data gathered from downhole temperature devices and wellbore temperature simulators to predict bottomhole circulating temperatures (BHCT). The cooling effects associated with the seabed conditions tend to complicate the simulation because of the need to determine times for cool-down and then heat-up rates. Data taken from drilling and evaluation instruments have been applied to estimate the temperature conditions for cement testing; however, simulations should be made to determine accurate cementing temperature profiles.

Currently the most common and practical method to determine BHCT is to use a wellbore temperature simulator; an example of the output from one of these is shown in **Fig. 4**. This simulation is performed for a well in approximately 6,800 ft water depth on a 20-in. conductor casing in the riserless mode. The results show a surface temperature of 80°F and a BHCT that approaches 50°F. Before confidence was gained in the

software-predicted temperatures, several methods were used in an effort to measure the cementing temperatures. In this example, temperature recording devices were placed at various points in the cementing discharge system and the wellbore. Temperature gauges were placed in the cement mixing tub and the cement discharge line to record surface temperatures during mixing and pumping operations. **Fig. 5** shows the temperatures recorded during this exercise; the ambient surface temperature was about 85°F, and as can be seen from the chart, the maximum recorded temperature was about 115°F at the beginning of mixing and about 105°F near the end of mixing.

The temperature increase in the mixing tub is attributed to the addition of mechanical energy in the mixer and the reactive nature of the cement. Temperature gauges were also placed downhole in the wellbore at two different locations to record temperature while cement slurry was being pumped. This well was in approximately 4,000 ft of water, one gauge was placed just below the mud line at 4,000 ft and the second gauge was placed near the bottom of the casing at 5,000 ft.

The start time for both charts is the start of cementing at just over 280 minutes. **Fig. 6** shows the results of both gauges. The 4,000-ft gauge started at about 43°F and increased to about 53°F during pumping, and the 5,000-ft gauge started about 48°F and increased to about 57°F. These results showed that the BHCTs being used by the industry at the time (from 65°F to 75°F) were very conservative but also confirmed the results seen on temperature simulations.

Another example (**Fig. 7**) shows the temperatures recorded by a measurement while drilling (MWD) tool on a different well. This well is in approximately 2,500 ft of water and shows temperature during drilling of the riserless hole section from a depth of 4,000 ft to 5,700 ft. The results of the MWD show a fairly constant temperature of 66°F to 71°F during the entire interval, likely the result of high mud-pump rates and some increase of temperature caused by the drilling process.

Waiting-on-Cement. Waiting-on-cement (WOC) times are used to determine the time to resume operations. This time can include installation or removal of wellhead equipment, riser, pressure testing casing, drilling out cement, or testing casing shoes. Care should be exercised in selection of WOC time to provide optimum cement properties for subsequent operations. Loads that impart shearing to the cement as it is setting (approaches initial set) may significantly affect the quality of the seal. Allowing high compressive strength to develop before pressure testing can increase the potential of shear-bond failure and hydraulic-seal failure during the pressure test.

With WOC time vs. rig cost a major consideration and seabed casing support mandatory for drilling operations to continue, a slurry design with rapid compressive

strength development becomes extremely important to a successful operation. Water and seafloor temperatures become the basis for slurry design optimization and laboratory testing.

Other significant factors that influence the temperatures used for cementing are the effect of heat of hydration of the cement on the temperature of fluid in the casing, and dissipation of this heat to the surrounding formation. The amount of heat energy generated depends on the mass of cement, maximum temperature of hydration and duration of the exothermic reaction.

Work performed with large-scale models and temperature simulators provided valuable information for determining curing temperatures, rather than simply using bottomhole static temperature (BHST). The method uses a simulated slurry temperature (SST).⁷ The SST is a curing temperature profile rather than just a single static temperature, is more representative of the actual cement slurry curing conditions, and gives a positive impact on the WOC time. Data was gathered in a well under in-situ conditions in approximately 4,000 ft water depth at different times after cement placement for a 20-in. casing in a 26-in. drilled hole. This data clearly illustrates the impact of heat of hydration on the (HoH) on cement curing temperatures and supports the SST.

Shown in **Fig. 8** are the log temperatures (1) beginning at the sea floor of 40°F at 4,000 ft and rapidly increasing to 60°F, (2) through the interval covered with lightweight lead cement, (3) then increasing slightly until reaching 5,250 ft (the top of the tail cement), then (4) increasing again to over 90°F at 5,500 ft on the 16-hour log run. The HoH increased the cement curing temperature as much as 35°F to 45°F over static temperatures.

After landing and cementing the casing, movement of or pressuring up the casing should be avoided until the cement has developed adequate strength for support of the casing. This is generally accepted to be 100 psi compressive strength. Across the potential SWF zones, wait on cement until 100 psi is achieved under in-situ conditions. When ultrasonic strength devices are used, a clear indication of strength development (cement hydration) can be used. When this condition is met, strength is adequate for all operations with the possible exception of pressure testing casing and drilling out the shoe. Pressure testing the casing and drilling out the shoe should be delayed until the cement at the shoe has reached 500 psi compressive strength.

Methods for determining WOC time include determination of strength development from laboratory tests, on-site strength testing, or evaluation of results from previous wells drilled in close proximity to the well or a combination of these techniques. The method used should depend on the risk of flow and other well parameters.

Temperature logs may be run to assist in determining the tops of cement as well as the setting time of the cement. This procedure, coupled with continuous profile of strength vs. time measured on an ultrasonic nondestructive test device, can help determine when the strength criteria are met. Consideration may be given to making strength measurements on-site for determination of WOC time. The only practical method of testing on-site is the use of an ultrasonic cement analyzer. Because this device uses a correlation to compute compressive strength, care must be taken that proper correlations are available and used.

For strength tests to be useful, temperatures must be carefully controlled to simulate (1) placement conditions including cooldown, (2) return to formation temperatures while static, and (3) the heat liberated during cement hydration. Computer thermal simulator models that take into account temperatures to which the cement will be exposed during placement and the heat buildup from heat of hydration can be used. These simulators take into account the heat exchange through the sea and in the wellbore as well.

The WOC time should be based on consideration of such factors as (1) the certainty of knowledge of temperatures in the well, (2) presence of gas, (3) history of annular flow incidents in the area, (4) the pore and fracturing pressures, (5) the occurrence of lost returns while cementing (6) contamination of the cement, and (7) other factors that may have impacted the cementing job.

At all times during waiting on cement, (1) activities that may disturb the cement should be minimized, (2) the well observed for indications of flow, and (3) well-control contingencies maintained. If flow occurs, control contingencies must be executed, as appropriate.

Cementing Tracer Systems

Use of tracer systems to identify early fluid returns to the seafloor helps minimize solids buildup at the seafloor and helps ensure that good cement has returned back to the mudline. A multitude of tracers have been used by the industry to help identify early returns of spacers and cement at the seafloor mudline.

Fig. 9 typifies foamed cement returns to the seafloor on a riserless cementing operation. Some of the more common types of tracers have been different types of dyes, predominantly red. Other tracers used in mud, spacers, and cement have been mica-type materials for viewing with downhole cameras. All of these techniques have been used for early detection with varying degrees of success. More recently success has been obtained using a green fluorescein dye placed in the spacer ahead of the foamed cement. Normally this spacer is weighted to the same density as the pad mud in the hole plus an additional 0.5 to 1.0 lb/gal before cementing. The dye is mixed in the spacer at a concentration of 0.2 gal/bbl of spacer. Spacer volumes are normally

around 100 to 200 bbl. **Fig. 10** shows the green fluorescein dye in the spacer reaching the seafloor on a recent cementing operation. The use of a pH meter operated and monitored with the remotely operated vehicle (ROV) has shown success in the detection of cement at the seafloor. Because the pH of cement slurry is much higher than the pH of the other fluids in the wellbore, the pH meter is an effective positive indicator of cement returns.

Figs. 11 and 12 show the use of a pH meter to detect cement at the seafloor. In this case, it was clear that cement had reached the seafloor as the pH increased from a reading of 9.7 to a final value of 13.6. One critical factor to consider when using the pH meter is the location of the probe. The probe should be located in the flow at the wellhead port to accurately detect increases in pH from the returning cement slurry.

Another tracer technique used ahead of the spacer with the pad mud is inclusion of tracer beads. Tracer beads in a mud pill are mixed through the hopper at a concentration of 40 lb/bbl of mud. Good dispersion of the beads in the mud is critical; operators should ensure that the paddles in the pit are turning to keep the fluid with the tracer beads agitated and stop the beads from floating to the top. The mud containing the tracer beads, followed by the spacer with the green fluorescein dye, is pumped ahead of the foamed lead cement. The ROV monitors for indication of the beads coming back at the sea floor. Observation of the beads by the ROV operator on location may require the ROV to zoom the camera very close to the discharge ports of the wellhead.

Adjustment of the back light may also be necessary to make it easier to see the beads. Also, the beads are white so they can be seen on black and white and color monitors. When the tracer bead returns are observed at the sea floor, total volume pumped including the mud with tracer beads, spacer, and foamed cement should be noted. A calculation can be performed using the known volumes of the drillpipe and casing shoe track capacities, etc. This volume subtracted from the total volume pumped and the volume left over is the volume of the annulus. Take this volume and divide it by the length of the annulus to get the barrel per foot (bbl/ft) factor, which can be converted to the actual hole size in inches. At the time of returning tracers, a decision can be made to switch to tail cement followed by seawater displacement.

The final indication of a successful riserless cementing operation is correlation between predicted and actual final lift pressure. This pressure gives final confirmation that adequate cement fill has been obtained behind casing with planned cement top at the seafloor. **Fig. 13** demonstrates the final lift pressure associated with a 22-in. casing job performed on a deepwater operation.

Downhole Equipment for Riserless Cementing

Riserless cementing takes place through an inner-string assembly with drillpipe end located 50 to 150 ft from the casing shoe. In most cases a double-valve float shoe is run, or there may also be a float collar. Installation of a diverter tool (**Fig. 14**) on the end of the drill-pipe stinger helps divert flow and clean the shoe track for reduced contamination of tail-cement slurry. This is very critical because casing must be successfully tested when the riser has been installed before shoe-track drillout.

Following successful cementing operations, a foam wiper ball is dropped to clean the drill pipe inside diameter walls of any cement sheath associated with the job. A foam ball is normally used because the ease of loading and pumping through associated pipe restrictions. For instance the 6-in. ball in **Fig. 15** has successfully passed through ID restrictions less than 2 in. with no more than 100 psi.

Conclusions

A number of best practices for cementing the riserless section of a deepwater well have been reviewed in this paper. Some new techniques have been presented for positive determination of cement returns at the sea floor. New information has also been presented about proper temperature determination, and downhole equipment to improve reliability of casing test. Best practices when applied can lead to a high success rate. The following new practices presented in this paper:

- Deployment of a pH meter on the ROV to identify cement returns
- Use of red dye, fluorescein dye, and tracer beads in spacers to determine hole volume and indicate leading edge of cement
- Addition of a diverter sub and a foam wiper ball with the inner-string cementing stinger to improve casing test
- Validation of wellbore temperature simulators to predict cementing temperatures in deepwater

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Nomenclature

<i>BOP</i>	=	<i>blowout preventers</i>
<i>ECD</i>	=	<i>equivalent circulating density</i>
<i>EMW</i>	=	<i>equivalent mud weight</i>
<i>SWF</i>	=	<i>shallow water flows</i>
<i>BHCT</i>	=	<i>bottomhole circulating temperature</i>
<i>BHST</i>	=	<i>bottomhole static temperature</i>
<i>ROV</i>	=	<i>remote operated vehicle</i>
<i>PPG</i>	=	<i>pound per gallon</i>
<i>RKB</i>	=	<i>rig kelly bushing</i>
<i>TD</i>	=	<i>total depth</i>
<i>TVD</i>	=	<i>true vertical depth</i>
<i>TTT</i>	=	<i>total thickening time</i>
<i>WOC</i>	=	<i>waiting on cement</i>
<i>BML</i>	=	<i>below mud line</i>
<i>MWD</i>	=	<i>measurement while drilling</i>
<i>SST</i>	=	<i>simulated slurry temperature</i>
<i>HoH</i>	=	<i>heat of hydration</i>
<i>bbl/ft</i>	=	<i>barrels per foot</i>
<i>psi</i>	=	<i>pounds per square Inch</i>
<i>bbl/min</i>	=	<i>barrels per minute</i>
<i>ft</i>	=	<i>foot or feet</i>

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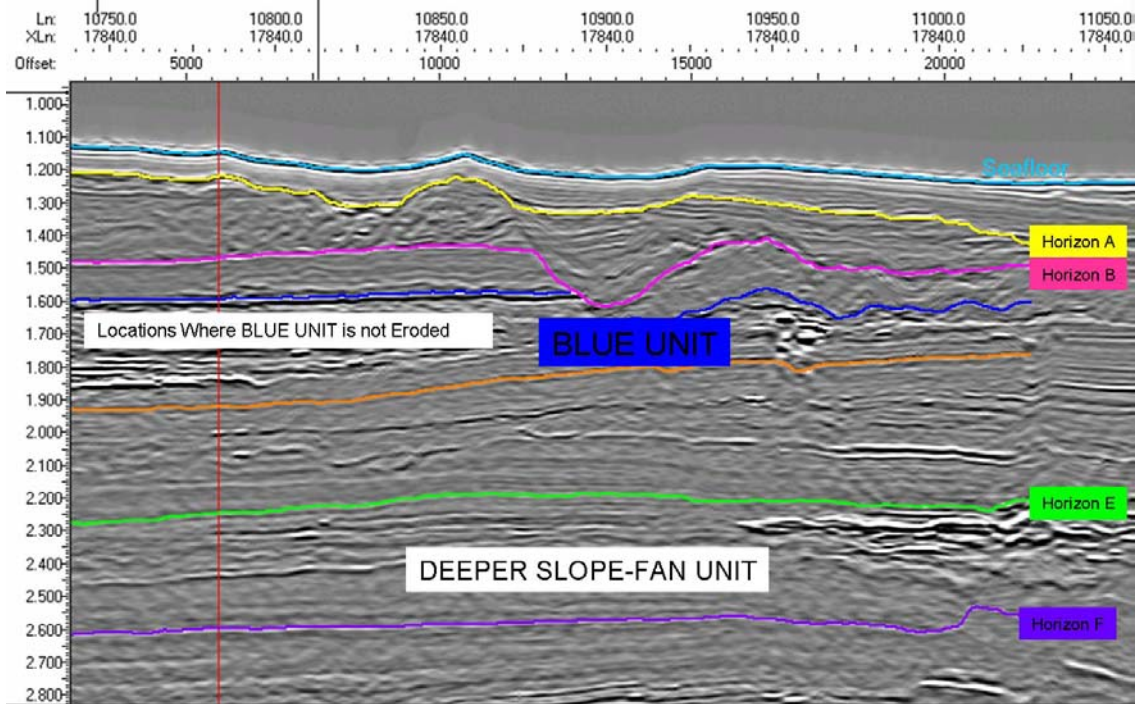


Fig. 1—Seismic event.



Fig. 2—Seafloor buildup.



Fig. 3—Consistometer equipped with chiller.

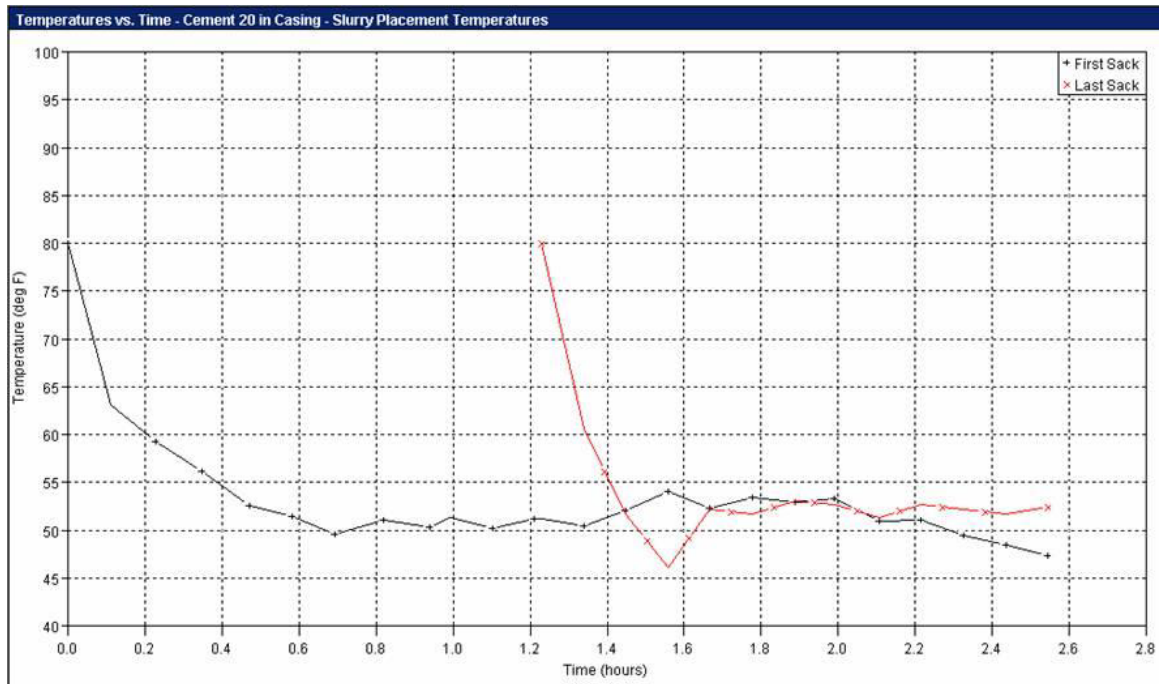


Fig. 4—Example thermal simulator chart.

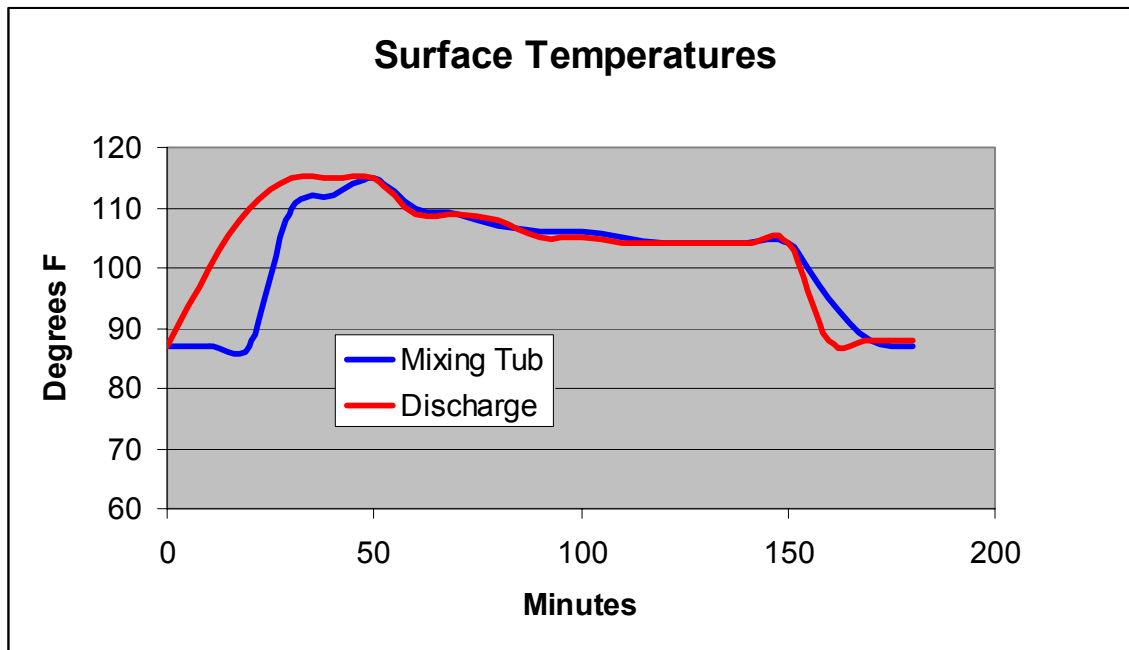


Fig. 5—Temperatures recorded on surface.

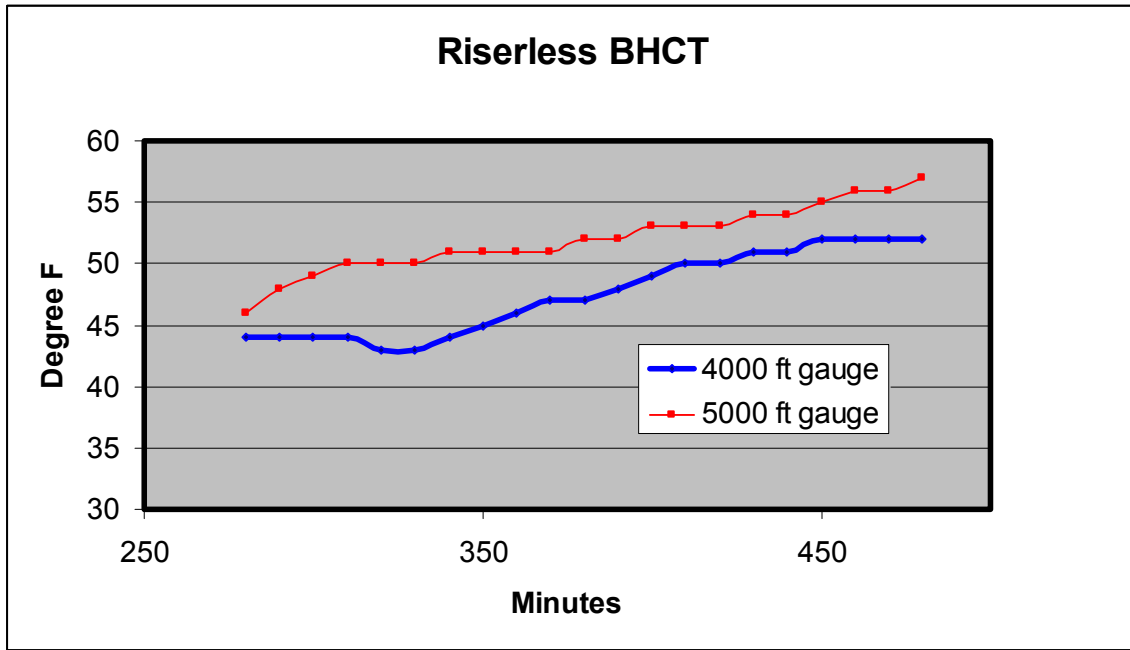


Fig. 6—Riserless cementing temperatures.

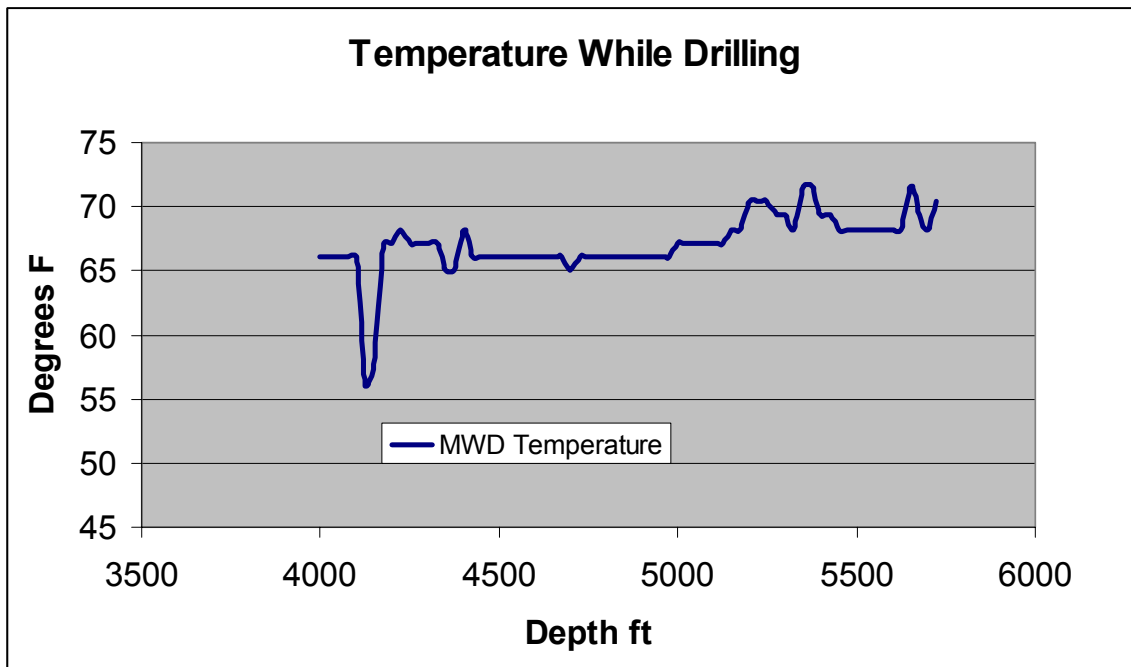


Fig. 7—MWD temperatures.

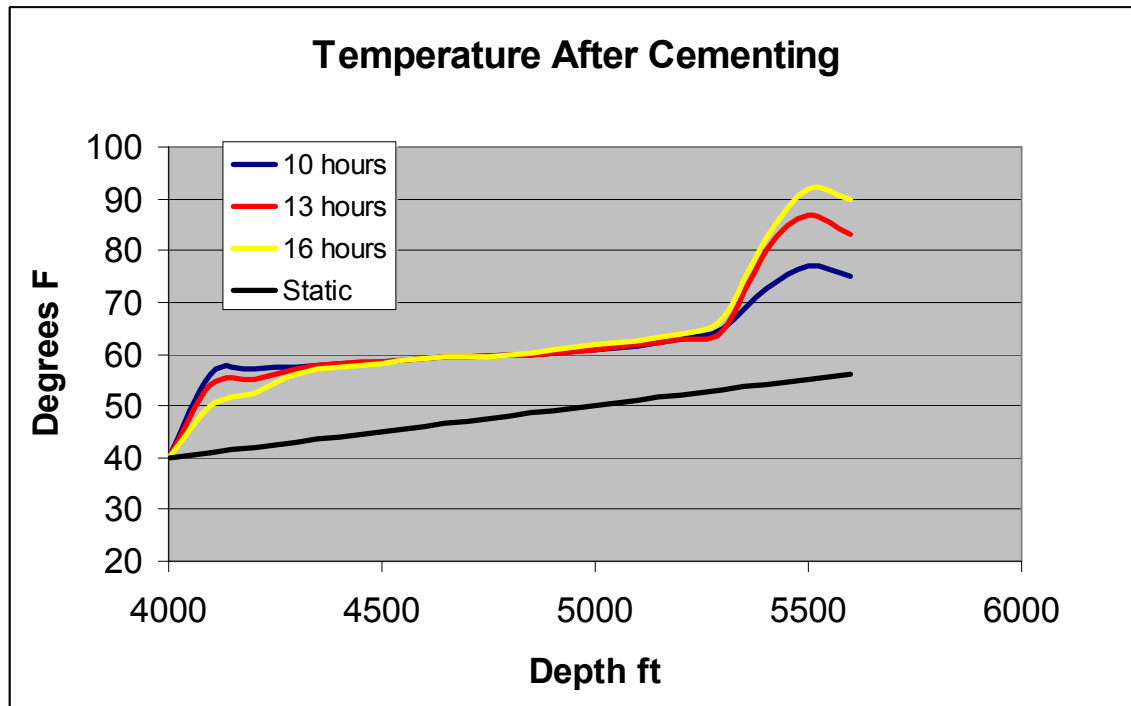


Fig. 8—Recorder temperatures after cement placement.



Fig. 9—Cement returns at the seafloor on a 22-in. riserless job.



Fig. 10—Identification of seafloor returns using green fluorescein dye.

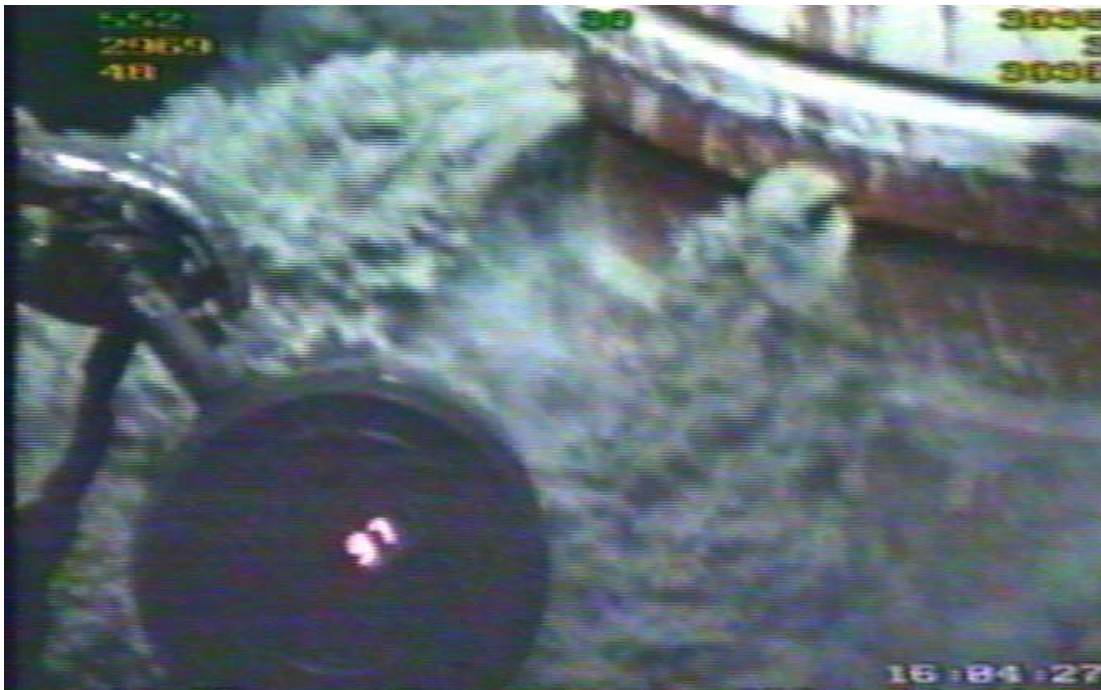


Fig. 11—Identification of fluid returns using pH meter reading 9.7.



Fig. 12—Foam cement returns identified using pH meter reading 13.6.

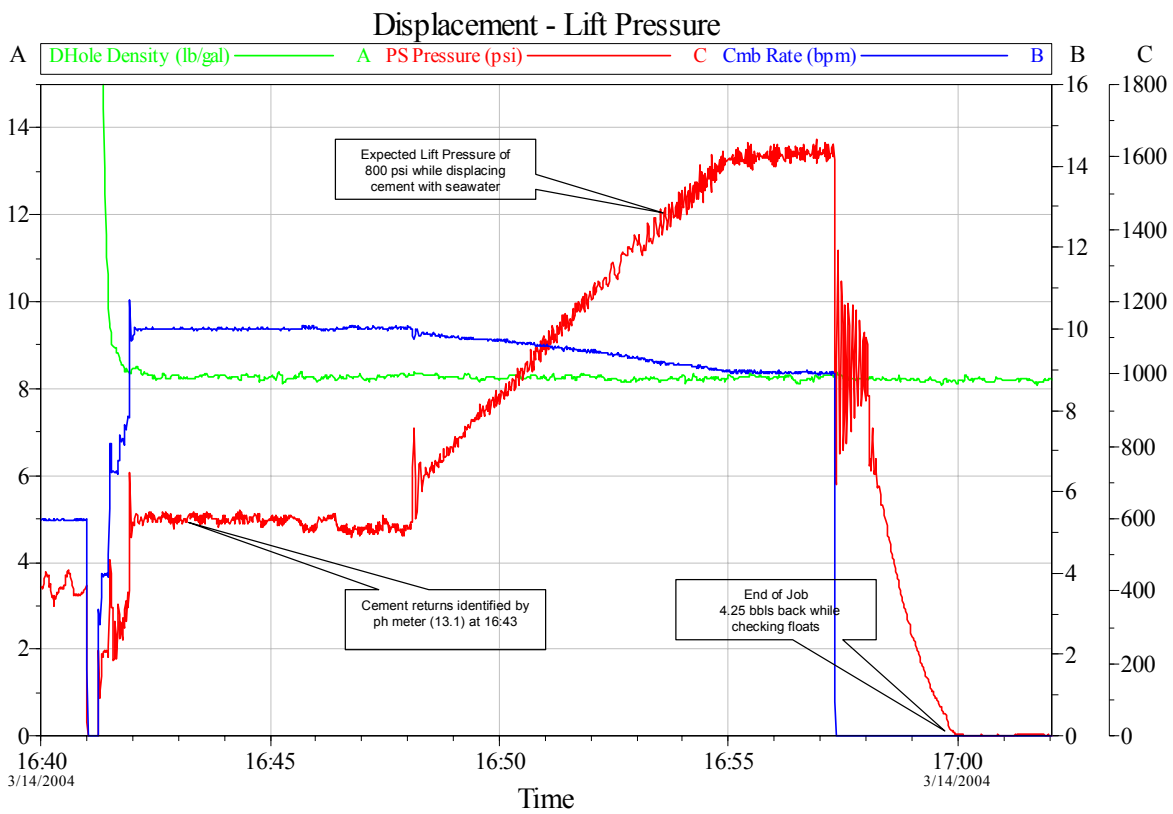


Fig. 13—Final lift pressure at the end of riserless job.

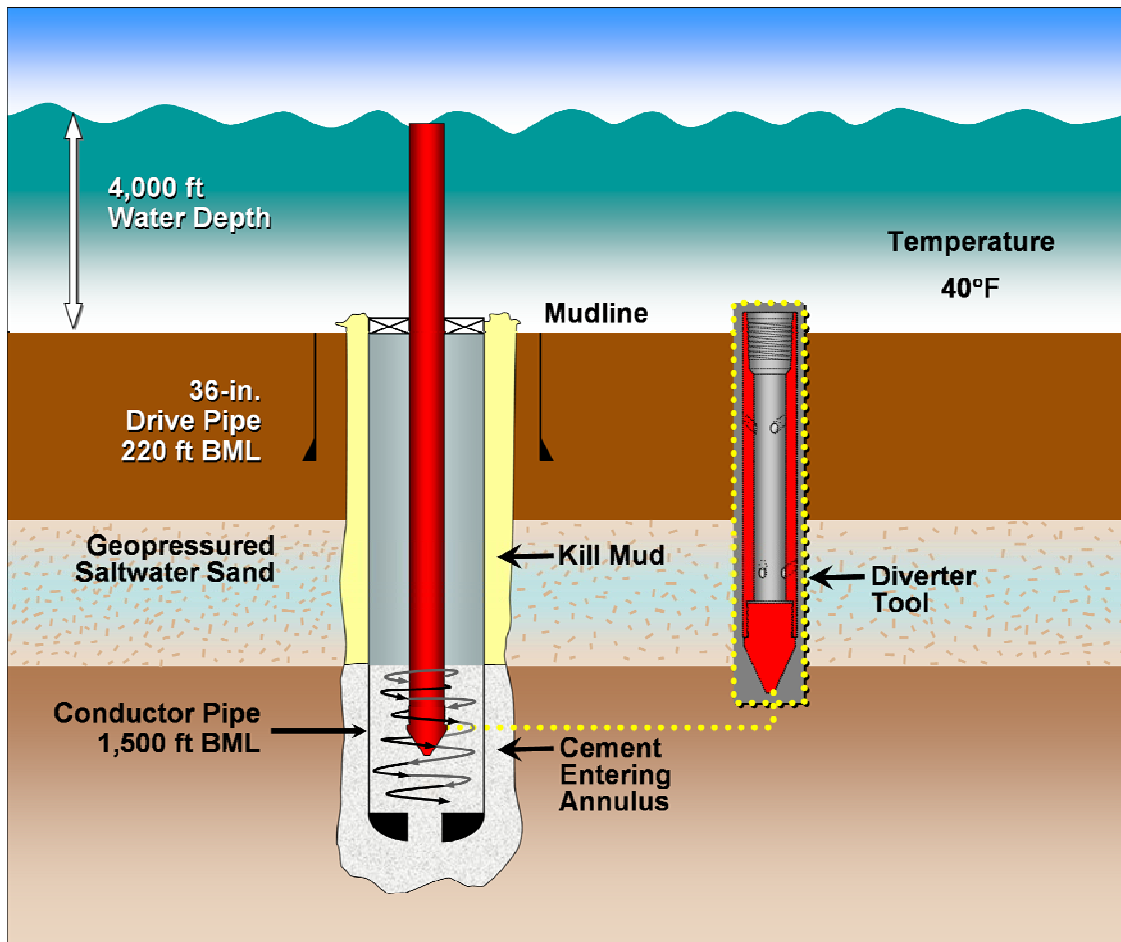


Fig. 14—Inner-string cementing with diverter tool.



Fig. 15—6-in. foam wiper ball.