AADE-20-FTCE-091

Increasing Primary Cement Job Efficiencies

Amy Farrar and Juan Carlos (J.C.) Mondelli, Frank's International; Sam Bond-Zielinski and Kyle Bradford - Operators

Abstract

There are several industry best practices to ensure a competent primary cement job. Surface equipment selection and limitations can restrict an operator's ability to implement some of these best practices and prevent them from realizing improved efficiencies in safety and rig time savings. Reducing static time, rotating while cementing with proper centralization, and keeping personnel out of the red zone can enable the operator to achieve a competent cement job while safeguarding their rig personnel against increased risk during the operation.

After landing casing, it is important to keep fluid moving to reduce static time and condition the wellbore for cementing. Standard cementing manifolds require the casing running tool (CRT) to be laid down before the cementing unit can be brought online.

This extensive down time delays the operator from being able to circulate and condition the wellbore. Numerous industry papers demonstrate that rotating while cementing creates a viscous coupling effect that breaks up the cuttings bed which can encumber zonal isolation objectives and compromise the primary cement job. Finally, rig personnel are needed in the red zone to make up standard cementing manifolds, load and launch casing wiper plugs, and make up the cement line.

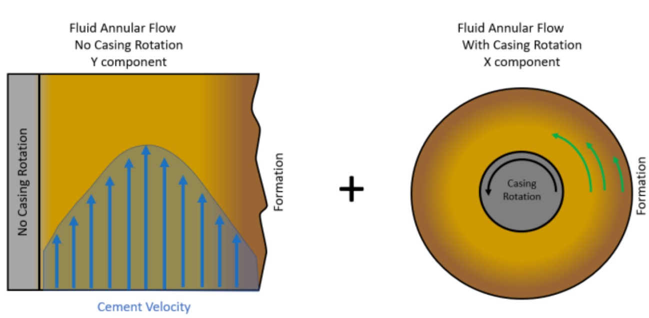
This paper will discuss current cement head technologies available to the operator that allow them to achieve the industry best practices for primary cementing while improving efficiencies in safety and operational rig time. It will also include case histories for this technology and lessons learned that can be applied through the industry.

Introduction

It is well understood that to achieve an efficient primary cement job, several proven methods need to be used in unison depending on wellbore geometry, formation integrity, hole conditions, and casing hardware. Most of these have limits to them and can only work in very specific circumstances. While pumping cement, turbulent flow is preferred but is dictated by gel strength, plastic viscosity, and formation pressures. In this paper we will focus on pipe movement and decreasing wellbore fluid static time, as they have been shown to be one of the least utilized techniques and yet the most effective. This practice is detailed in an article regarding pipe movement to maximize displacement, where despite an industry understanding of the advantages for pipe movement less than 10% of cement jobs worldwide use this method (Holt 2013). Although cost may prohibit an operator from exploring the technology available to allow for pipe movement or rotation, the cost of remediation can be high. This was previously discussed in a paper to review primary cementing success in Katy Field, where the authors explored the implementation of reciprocating and rotating a 7-5/8" liner string using a surface power swivel. The formation was such that the operator averaged eight squeezes on the nine wells they drilled before implementing rotation. They saw a reduction from eight secondary cement squeezes per well to three squeezes saving an estimated six days and $156,000 for each repair job. In addition, the 73% reduction in overall failure rate on the primary cement job extrapolated to a total of 108 days of rig time and $2.25 M savings for the wells drilled after casing rotation was implemented. (Cowthran 1982)

Numerous studies, as shown in the references section of this paper, discuss how cement bond logs performed across zones demonstrate a direct correlation between areas with large amounts of filter cake and poor cementing bonds. The effective removal of this thick mud cake is essential to the success of the primary cement job. The presence of an extremely thick mud cake opposite the zone correlates with poor cement bonding and drawdown pore pressure. Consequently, primary cement failures can be attributed to three major factors: Lost returns, excessive filter cake and insufficient mud displacement (Cowthran 1982). Fluid traveling parallel to the pipe and only being pumped at a specific velocity will take the path of least resistance and allow long continuous channels to form. Pipe movement, and specifically rotation of the pipe, helps create the turbulent float needed to directly improve both removal of filter cake and mud displacement. The drag forces generated from the moving pipe, transfers to the adjacent fluid traveling along the wellbore. This force redirects the fluid transversely and produces a turbulent like effect where otherwise there would be none. The new helical and axial fluid path, that is introduced with pipe movement, enables a larger amount of filter cake to be removed prior to the cement job. It also removes potential mud channels during the cement displacement, far reducing the chances of having to perform any remedial cementing operations.

As mentioned earlier, part of the necessary fluid movement to achieve a competent primary cement job is viscous coupling. This is the phenomenon that breaks away excess mud cake along the formation walls, as well as the settled solids along the bottom section of the long horizontal profiles. Viscous coupling can be achieved by using the pipe to move fluid and place it in locations where otherwise it would not flow. See Figure 1 showing the viscous coupling affect. To capitalize on this benefit, additional torque values at the surface and increased tensile may be required to create the pipe movement. When rotating pipe, the torque values will typically increase to the point where rotation must be stopped so the maximum torque of the connection chosen is not surpassed. The same considerations should be made when reciprocating pipe, along with ensuring the swab and surge effect as you move the casing does not adversely affect the formation. A thorough selection of low friction solid body centralizers and high strength connections allow for maximum torque and/or axial movement to be transmitted into the cementing slurry and assist in displacing unwanted mud channels. Proper centralizers and centralizer placement allow the torque and drag losses to be mitigated from the system for proper energy transmission from the top drive or CRT, down into the casing at the exposed formation.



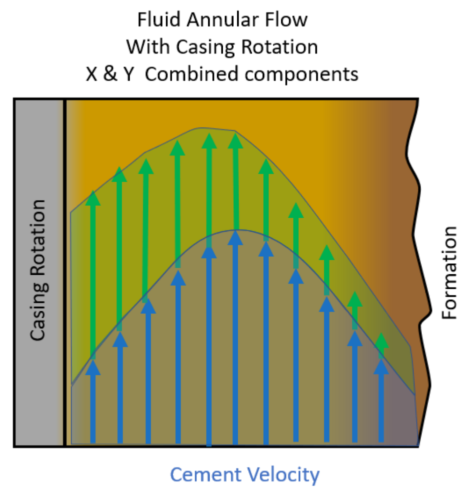


Figure 1 – Shows the viscous Coupling Effect using pipe rotation as cement is flowed through the annulus

The case studies listed in this paper will show a direct improvement comparing a well where no pipe movement was used during the cement job, versus the ones where pipe movement was effectively used by sourcing the correct automated cement head equipment and the proper high torque casing connections. These actual well results add more examples to the abundance already published, that point toward pipe movement as an effective technique when it comes to successful mud filter cake removal and efficient primary cementing and the required equipment to perform the job safely and efficiently.

Field Results

US Land Case Study

An operator who drills wells in the Marcelles and Utica shales in the Northeastern US, drilled three wells in the same area using the following parameters:

- Well #1 – Centralized 1 per 3 joints. Not rotating casing during cement.
- Well #2 – Centralized 1 per 3 joints. Rotated casing during cement and pumped a cement additive that limits fluid migration through mud channels.
- Well #3 – Centralized 1 per 3 joints. Rotating casing during cement. Without the cement additive.

The first well (Well #1) was drilled to 26,345' MD with a ~16,000' long lateral. 5.5" casing was run to total depth with 136 solid body centralizers. The cement job was performed as follows: launched bottom plug from the non-rotating cementing manifold with 92 BBL of mud, 373 BBL lead cement, 661 BBL tail cement. After pumping cement, the cement pump was shut down to wash the pumps and lines. After washing, the top plug was launched from the cement manifold. Cement was then displaced with 557 BBL total (180 BBL fresh water, 377 BBL production water with the first 20 BBL containing sugar). The top plug was landed at 3.4 BPM with 3,900 psi. Pressure was increased to 4,500 psi (600 psi over) and held for 5 minutes. Pressure was bled, with 7 BBLS back to pump truck when floats were checked, confirming that the floats were holding. Full returns were observed during the job. Top of tail cement after the job was estimated at 10,505'. Figure 2 shows the cement bond log from this job. The results from this bond log show that mud displacement was poor resulting in channeling and less than desired zonal isolation for completions. Laminar flow was dominant during cementing from lack of pipe rotation. As part of a three well test, the goal was to evaluate different pumping and pipe movement scenarios and based on results from each CBL, modify cementing practices moving forward.

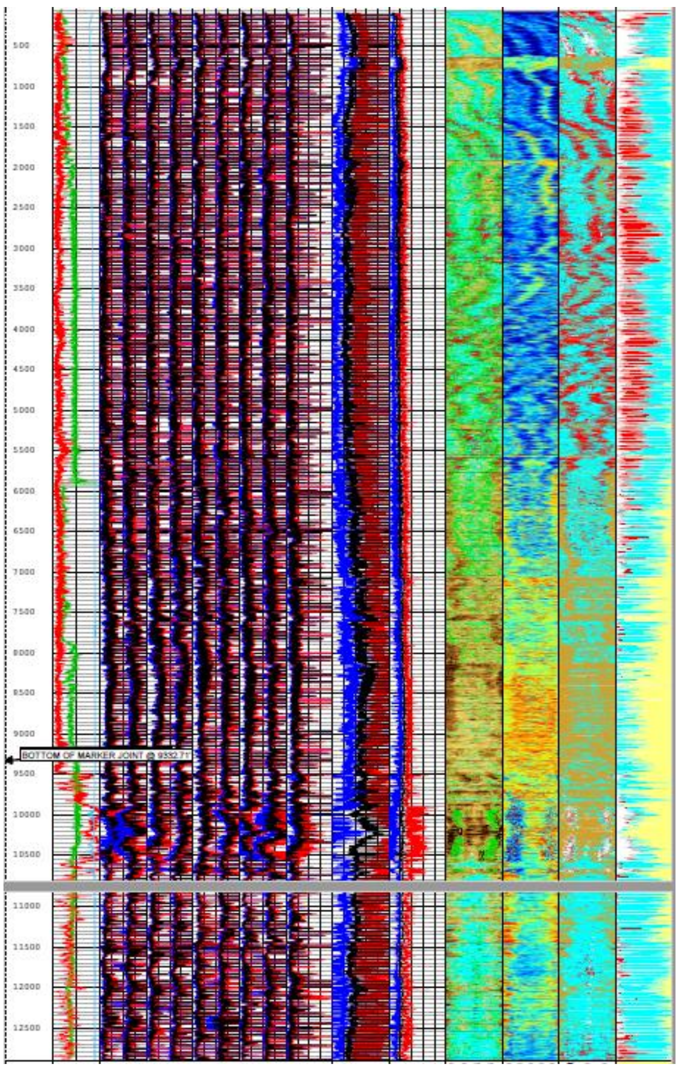


Figure 2 – Cement Bond Log from Casing that was not rotated

As part of a three well test, it was decided to rotate the 5.5" casing string on the next well and to incorporate a cement additive that limits fluid migration through mud channels. The following considerations were made before the job to ensure rotating success:

- Casing connection
- Torque and Drag (T&D) modeling
- Surface equipment limitations
- Centralizer type and placement

Typically, an API buttress connection is considered for this casing type because it is readily available and inexpensive, however, when rotation is needed during the cement job to achieve the desired zonal isolation results, a casing connection with a higher operating torque needs to be utilized. Knowing the amount of torque it will take to rotate the casing can be determined by performing T&D modeling. Since rotation throughout the cement job yields the best results for the cement placement, the T&D model must not only be run as the casing is landed but the torque should be evaluated throughout the entire cement job. For this well, a preliminary T&D model was run showing the anticipated torque when the casing reaches total depth (Mud In, Mud Out), when cement is about to exit the casing at the shoe (Cement In, Mud Out), half way through displacement (Cement In, Cement Out), and then at the end of the cement job (Displacement Fluid In, Cement Out). Looking at these points allows the operator to understand and anticipate the changes in torque while pumping the job. Figure 3 shows the torque results from the pre-job T&D model.

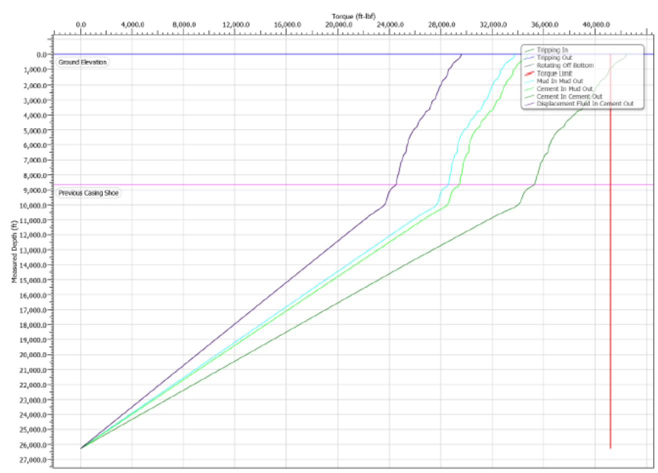


Figure 3 – T&D Modeling Results showing rotation is possible through most of the cement job

After running the modeling and determining the torque required to rotate the casing, the operator then must consider what surface cement head will allow them to achieve the torque requirements. A typical cement manifold used to drop casing wiper plugs does not allow for rotation while pumping cement. A manual cement head with swivel will allow for rotation but requires rotation to stop to drop plugs and close or open isolation valves. Once rotation is stopped, it is difficult to re-establish, due to the static friction that needs to be overcome to get the casing moving again. It is important to establish rotation as soon as possible to when the casing is landed and to continue rotation throughout the cement job (M.A Arceneaux et al, 1986). A fully-automated cement head that can quickly be made up to the casing running tool (CRT) or top drive and allows for rotation to continuously occur during the cement job, gives the operator the best chance of rotating throughout and achieving their primary cement job objectives. Rotating casing provides essentially the same results as increasing the displacement rate. It allows for lowering the gel strength of the mud and improves the ability to displace it while cementing (Cowthran 1982).

It is well known amongst cementers and operators that centralizing the casing and proper centralizer placement is an important component to achieving a competent cement bond (Sauer 1987). However, some centralizers can increase the torque required to rotate the casing, thus impeding the operator's ability to continue rotation as the cement is pumped and displaced. A T&D model run during pre-job planning can help an operator determine the proper centralizers and placement needed to achieve both good standoff and the torque required to rotate.

Taking the above items into consideration, the operator opted to utilize a fully-wireless cement head, solid body centralizers, and a casing connection that allowed for an operating torque of 41,180 ft-lbs.

The second well (Well #2) was drilled to 26,280' MD with a ~16,000' lateral length. 5.5" casing was run to TD with solid body centralizers. At 19:00, a safety meeting was held to review the cement head lifting and makeup procedure and then at 19:30 the cement head was lifted into the derrick and made up to the top drive and casing stump. The lo-torque was wirelessly closed and circulation commenced at 19:35 through the top drive, limiting the well static time to 35 minutes. After the cement line test, the lo-torque was wirelessly opened and the cement job commenced. The bottom plug was launched wirelessly with 100 BBL of spacer, rotation of the casing was started at 15 RPM and 21,000 ft-lbs. Then 367 BBL of lead and 642 BBL of tail cement was pumped. Pumping was then shut down to wash pumps/lines. Rotation continued during this time at 15 RPM and 20,000 ft-lbs. The top plug was launched wirelessly from the cement head and cement was displaced with 555 BBL (first 20 BBLS w/ sugar) 180 BBLs fresh, 375 BBLs production water. The top plug landed at 3 BPM and 3,750 psi. Pressure was increased to 4,350 psi (600 psi over bump pressure) and held for 5 minutes. Pressure was then bled back 7 BBL to the pump truck to check the floats and it was confirmed that the floats were holding. Full returns were observed during the job. The top of the tail cement was calculated to be at 10,554', with the top of the lead cement at 2,423'. Pipe rotation stalled out at 625 bbls into tail cement. Figure 4 shows the cement bond log from this job. In this scenario, competent cement quality and zonal isolation were obtained through pipe rotation while cementing. Channeling has been reduced and turbulent flow achieved with the addition of pipe rotation. Additives pumped in the cement blend seemed to further increase zonal isolation and were validated with higher breakdown pressures.

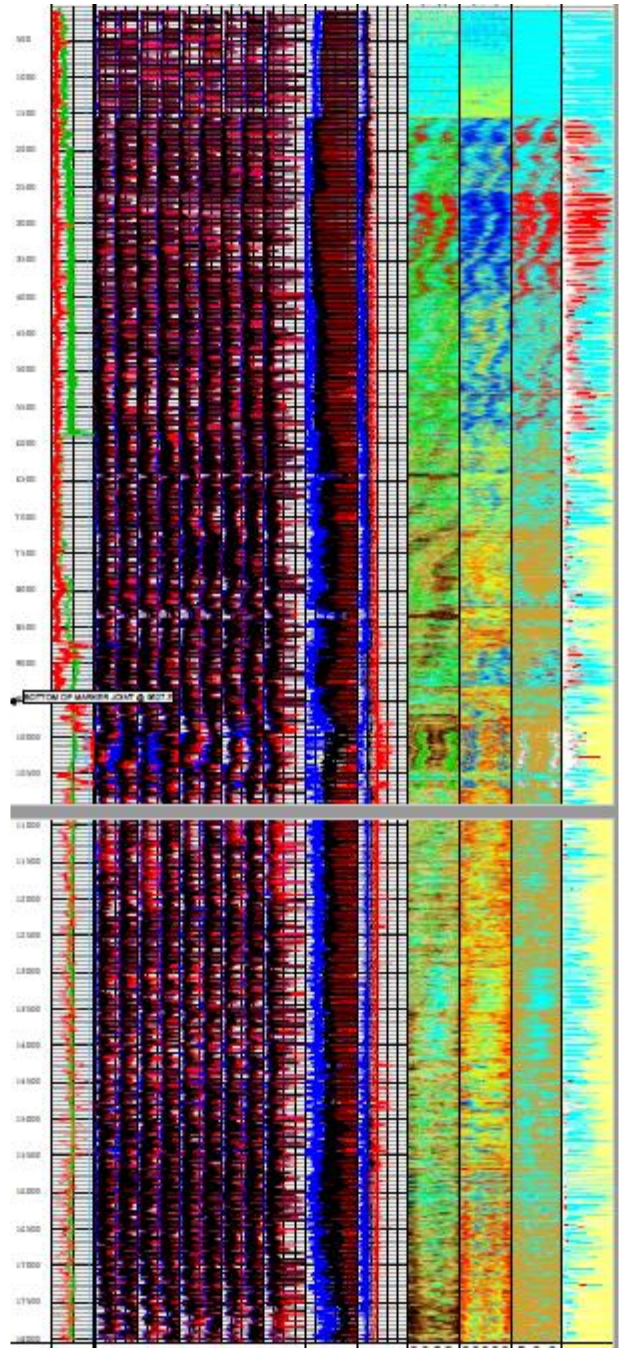


Figure 4 – Cement Bond Log from Casing that was rotated through most of the tail cement

As part of a three well test, it was decided to rotate the 5.5" casing string on the next well and to review the results of the job without the cement additive.

On the third well (Well #3) the casing was run to 26,620' MD with 142 solid body centralizers. The lateral length was ~ 16,000'. The following T&D model was performed to determine the anticipated torque during the cement job. See Figure XX for results of the torque model.

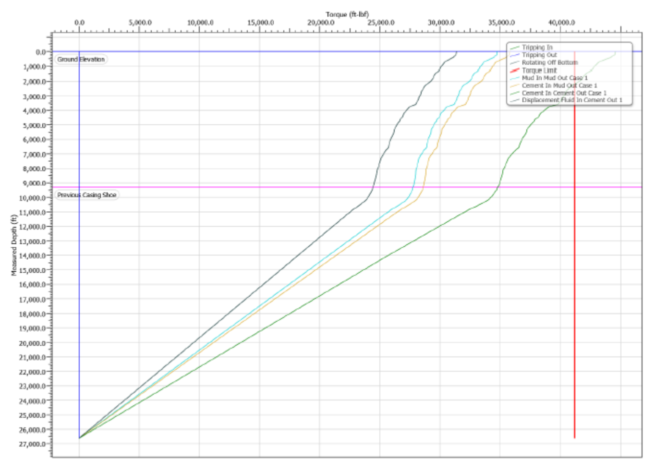


Figure 5 - T&D Modeling Results showing rotation is possible through most of the cement job

At 08:20 the safety meeting was held, and circulation commenced at 09:15, limiting static time on the well to 55 minutes. Rotation commenced with 19,000 ft-lbs of torque. The cement job was then performed. The bottom plug was launched wirelessly with 100 BBL of spacer followed by 1,020 BBL of tail cement. After shutting down to wash pump and lines, the top plug was wirelessly launched as rotation of the casing continued. The cement was then displaced with 562.7 BBL (200 BBL Fresh water, 363 bbls Prod water first 20BBLS w/ sugar). The top plug was landed at 3.8 BPM with 3,670psi. The pressure was then increased to 4,300 psi (630 psi over bump pressure) and held for 5 minutes. Pressure was bled back 7.0 BBL to the pump truck to check the floats, confirming they were holding. Full returns were observed during the job. Estimated top of tail cement was determined to be at 2,477'. Pipe rotation stalled out at 32,000 ft-lbs, ~50 bbls into displacement with top of Tail cement estimated @ 13,900'. Figure 6 shows the cement bond log from this job. This bond log showed similar characteristics from a cement quality and zonal isolation standpoint comparable to the second well. Again, pipe rotation created turbulent flow increasing mud displacement and significantly reduced channeling. Increased zonal isolation was confirmed during completions with higher breakdown pressures.

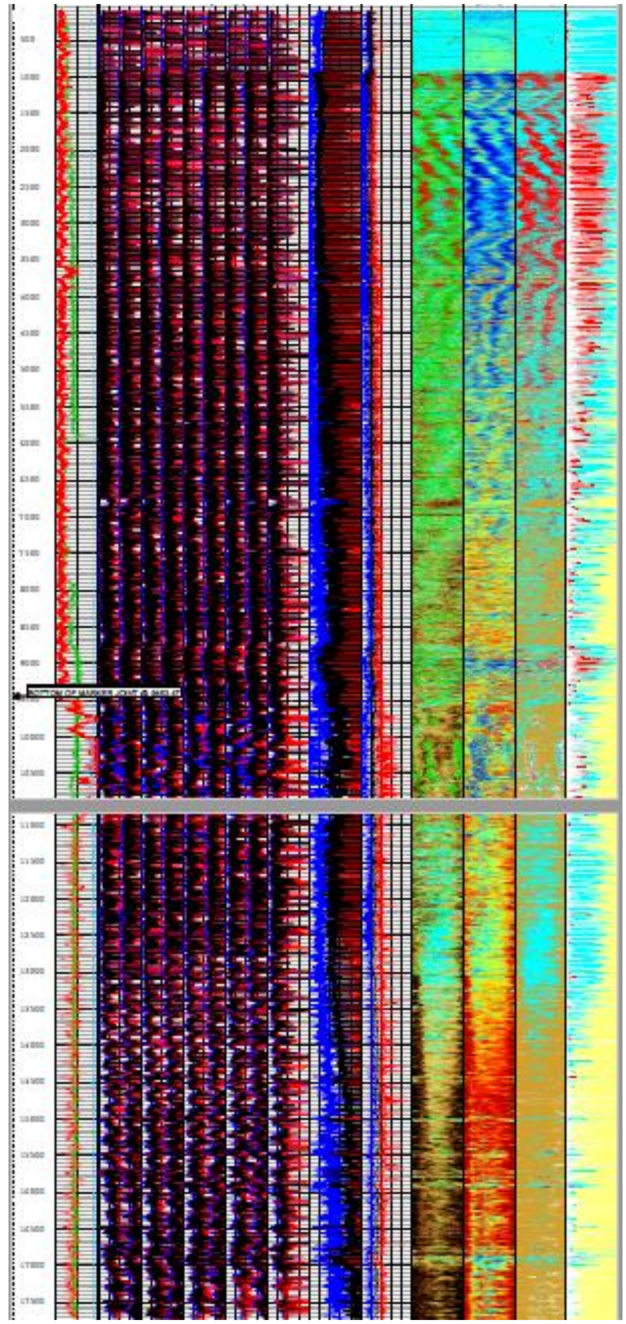


Figure 6 – Cement Bond Log from Casing that was rotated up to 50 bbls into displacement

Shallow Water Case Study

An international operator was running a long deviated 9-5/8" casing section where they were experiencing gas migration and annular casing pressure buildup. Their pre-job cementing analysis showed that even with ideal centralization of the casing (2 per joint in horizontal and 1 per joint in vertical) and proper wellbore conditioning, the only way to achieve a competent cement job would be with casing movement. See Figure 7 showing preliminary analysis.

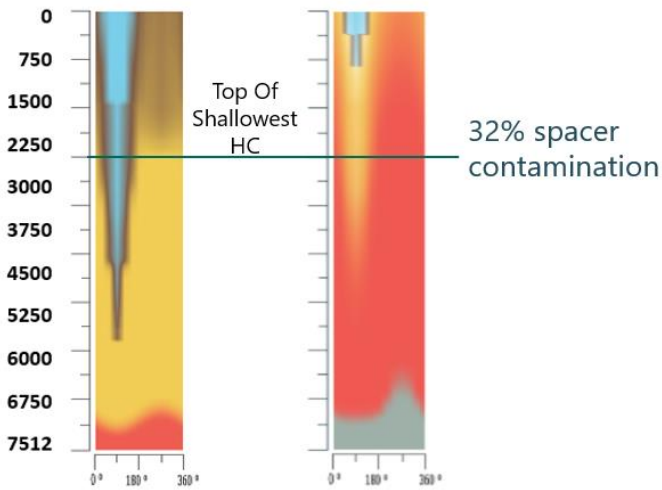


Figure 7 – Preliminary cement modeling showing cement contamination

There are several key factors in achieving a competent cement job for wellbore isolation once the casing is on bottom that the operator explored:

- Properly conditioned wellbore fluids (pre-job conditioning)
- Proper ccentralization
- Proper spacer type and volume
- Pipe movement (reciprocating and/or rotating during cementing)

The primary objective for the operator was to achieve their primary cement job objectives safely and efficiently, by minimizing fluid static time and moving the pipe. Due to the casing wellhead design which prevented rotation, reciprocation was the only pipe movement option. In order to accomplish this goal, a surface cementing head that allowed them quickly rig up, circulate almost immediately, drop 9-5/8" plugs, and keep personnel out of the red zone by providing wireless actuation was necessary. To see if the wellbore would allow for reciprocation, a T&D model was performed with the plan centralization program. The hook load results of the T&D model can be seen in Figure 8.

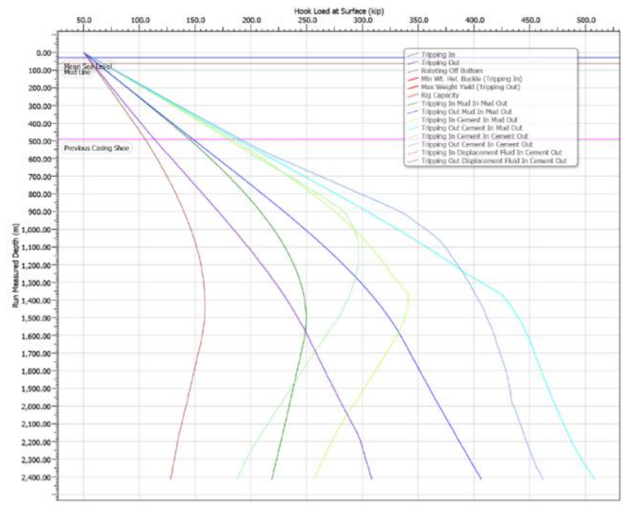


Figure 8 - T&D Modeling Results showing hookload results through the cement job

After determining that the hook load results were within the operating limitations of the rig and casing, a site survey was conducted to determine the best way to handle the cement head for the job. The 9-5/8" plug launching cement head was picked up with the CRT and slip type elevators. The tool was made up to the casing stump and circulation was established to condition the wellbore for cementing in approximately 30 minutes versus 2-3 hours with conventional manifold, improving fluid condition for better cementing. The well was conditioned at the maximum rate possible, to obtain turbulent flow in the annulus, without exceeding the equivalent circulating density (ECD) that could fracture the formation and induce cement losses.

A wireless lo-torque valve and wireless cement line make-up device allowed the operator to commence circulation while making up the cement line. The casing was reciprocated a distance of 5 m (16.4 ft) at approximately 3 m/min (9.8 ft/min). The stroke length was determined by the distance between the wellhead and BOP. Caution was taken to avoid picking the hanger up into the BOP stack or slacking off to the hang off point in the wellhead. Reciprocation began immediately after the tool was made up to the casing string and continued until the hanger was landed into the wellhead, when the calculated volume of lead cement entered the previous shoe during displacement. Figure 9 shows the surface cement head configuration after make-up.

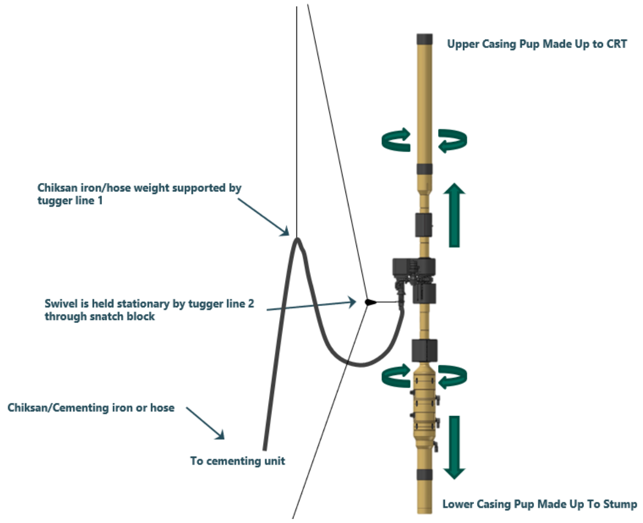


Figure 9 – Cement head makeup diagram

Once the cement head was rigged up, the string was reciprocated 5m during fluid conditioning, improving rheological properties of the downhole fluids and enhancing filter cake removal in preparation for cementing. Circulation continued while the cement line was lifted wirelessly into position and only stopped to switch from rig pumps to cement unit. The bottom plug was dropped wirelessly and cement was pumped. The top wiper plug was released wirelessly, and reciprocation continued until lead cement entered the previous 13-3/8" casing shoe in the annulus and wellhead was landed. The top plug bumped at calculated displacement volume. Pressure was then increased to 3,000 psi to test the casing. Casing was reciprocated during entire cement job, drastically improving cement displacement efficiency. There were no losses recorded during the cement job and cement returns were observed at surface. The entire cement job was conducted without sending personnel into the red zone or at heights above the rig floor. Figure 10 shows the cement bond log that confirms cement placement objectives were achieved.

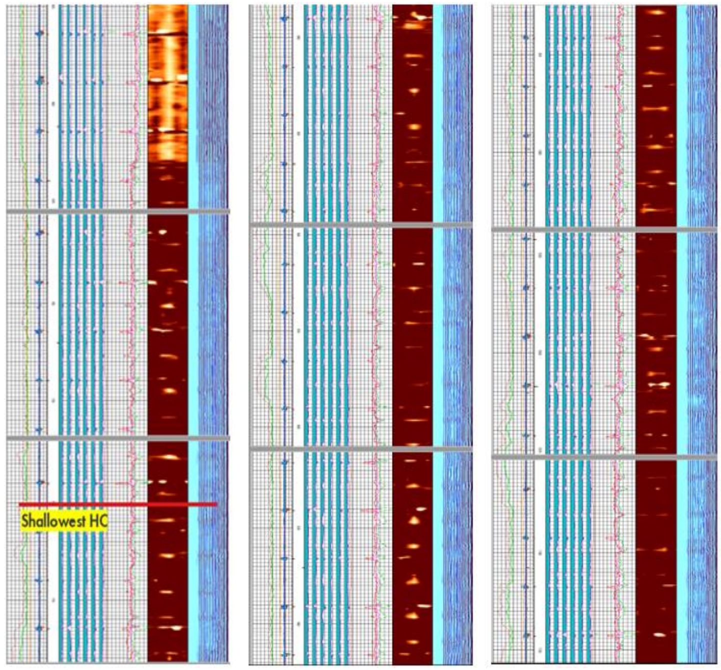


Figure 10 – Final cement bond log showing cement above the shallowest hydrocarbon zone

Best Practices and Lessons learned

To accomplish the best results on a primary cement job and minimize the risk of future remedial operations, pre-planning is crucial. The following items should be considered if pipe movement is required to achieve a competent primary cement job the first time.

- Use a high torque casing connection that is in line with the pre-job torque and drag modeling
- Consider a rotating cement head that allows for automated actuation and quick make-up time to minimize wellbore fluid static time
- Use centralizers that allow for rotation of casing while reducing drag forces and proper standoff.
- If CRT is to be used during casing running, make sure it is compatible with the torque values for casing rotation or reciprocation.
- Plan to start pipe movement and circulation as soon as the cement head is made up to the string. This will allow the filter cake to be broken up while cementing equipment is being moved into place.
- Plan to rotate throughout the cement job by launching plugs or darts remotely. This will allow rotation to be maintained until the fluid coupling effect increases the torque to the point that rotation needs to be stopped.

Conclusions

When faced with the challenges of longer and deeper wellbores, operators benefit from utilizing new technologies that allow them to accomplish field proven practices to ensure a competent primary cement job. Fully automated cement heads that allow for reduced wellbore fluid static time, rotating while cementing or pipe movement while cementing, and keeping personnel out of the red zone can enable the operator to achieve their primary cement job objectives while safeguarding their rig personnel against increased risk during the operation. The case histories studied in this paper show that the benefit of rotating or reciprocating the pipe to get the wellbore mud moving and breaking up the filter cake leads to a better cement bond and an improved chance of meeting zonal isolation and well barrier objectives the first time.

Acknowledgments

The authors of this paper wish to thank the operator for their permission to publish and present this paper using actual data from their wells. The authors would also like to thank Frank's International management

Nomenclature

BBL = Barrels
BPM = Barrels per Minute
PSI = Pounds per Square Inch
RPM = Revolutions per Minute
CRT = Casing Running Tool
CBL = Cement Bond Log

References

1. Arceneaux, M.A., Smith, R.L. 1985. "Liner Rotation While Cementing: An Operator's Experience in South Texas" – SPE/IADC Drilling Conference, New Orleans, LA, Mar 6-8, 1985. SPE 13448
2. Cowthran, J.L. 1982. "Technology Used To Improved Drilling Performance and Primary Cementing Success in Katy Field" – 57th Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME, New Orleans, LA, Sept 26-29, 1982. SPE 10956
3. Enayatpour, S., Van Oor, E., 2017. "Advanced Modeling of Cement Displacement Complexities" – SPE-184702-MS
4. Haut, R.C., Crook, R.J. 1979. "Primary Cementing: The Mud displacement process" – 54th Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME, Las Vegas, NV, Sept 23-26, 1979. SPE 8253
5. Holt,C., Lahoti, N., Fortier, V. 2013. "New cementing method uses pipe movement to maximize displacement" – Article Innovating While Drilling, March 18, 2013 https://www.drillingcontractor.org/new-cementing-method-uses-pipe-movement-to-maximize-displacement-21248
6. Sauer, C.W. 1987. "Mud Displacement During Cementing: A State of the Art" – Journal of Petroleum Technology – SPE Distinguished Author Series, Sept 1987. SPE 14197
7. Sutton, D.L., Ravi, K.M. 1991. "Low-Rate Pipe Movement During Cement Gelation to Control Gas Migration and Improve Cement Bond" – 66th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, TX, Oct 6-9, 1991. SPE 22776