Part 9 How to Run and Cement Liners

Five case histories of recent drilling and production liner jobs detail field procedures that provided acceptable results. Included are solutions used to solve operational problems encountered.

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IN THE PREVIOUS EIGHT INSTALLMENTS of this series, the authors have discussed many practical and theoretical aspects of liner cementing, such as rotation and reciprocation, getting liners to bottom, dealing with flash setting cement, preparing liners for testing, using packers, preventing annular gas flow, remedying lost circulation and cement squeeze techniques.

In this final part, five case histories are discussed where good liner cementing practices were used. Four wells are located on shore the Texas-Louisiana Gulf Coast and one on-shore California.

Case 1: *Production Liner, Wharton County, Texas.*

Ashland Exploration drilled its R. L. Fields No. 1 to a TD of 14,465 ft 9 5/8-in. casing was set to 7,589 ft, and a 7 5/8-in. drilling liner to 11,154 ft. A 6 ½-in. hole was drilled to 14,465 ft. Numerous lost-returns were encountered while drilling with 17.6-ppg mud to control shale. Reaming was necessary on all trips to go back to bottom. The well was logged and a decision made to run a mechanical set 5-in. liner. A "piggyback packer" was not run because this would preclude rotating or reciprocating. Since three zones close to bottom were to be tested, the operator decided it would be more economical to have a squeeze only the top of the liner if returns were lost. By rotating, it was felt that three or more squeeze jobs on the test intervals could be saved.

A pore pressure plot indicated no exposed sand had pressures close to the mud density, so no potential well control problems existed if returns were lost. A 3,614-ft, 5-in. LT&C liner was run with one slim-hole centralizer on every joint. Centralizers were allowed to float. As noted earlier, the heaving shale problem due to being underbalanced in pressured shales could not be solved. The liner was run to 13,665 ft, could not be washed deeper by rotating, and was pulled. All centralizers are intact. A conditioning trip was made, and the hole was reamed from 13,482 to 14,465 ft.

The hole was still making excess shale. It was believed heaving shale may have been trapped under bow springs on certain centralizers, preventing one of them from collapsing fully in a tight spot. To combat this, rigid body centralizers were run and allowed to float. This allows rotation but will not let hole debris become wedged under a centralizer. Hanger slips were removed and a 6 ½-in. bit was made up on the bottom of the liner.

The 5-in. liner was rerun. The hole had to be reamed numerous times at 13,665 ft. Mud was conditioned and the liner reciprocated. Mud weight was not reduced while circulating to prevent aggravation the heaving shale problem, and possibly pack off the annulus. When getting bottoms up, excess shale was again coming over the shaker.

The liner was cemented with 40 bbl of 17.6-ppg spacer followed by 140 sacks of batch mixed anti-gas-migration cement mixed at 17.9 ppg. The liner was rotated at 20 to 30 rpm until cement started filling the annulus. Rotation was increased to 40 rpm until the end of the job. Cement was pumped a 3 bpm to minimize the equivalent circulating density.

No cement was circulated on top of the liner because hole volume was underestimated, probably due to pressured shale sections washing out while circulating. The liner top had to be squeezed. Three zones were tested below 13,800 ft with no squeezing required. The bond log showed 95 to 100% bonding across test zones an estimated displacement efficiency to top of cement was 87%.

Case 2: *Production Liner, Cameron Parish, Louisiana.*

Ashland Exploration drilled Sweetlake Land and Oil Co, No. 4 to a TD of 12,500 ft; 9 5/8-in. casing was set at 8,900 ft. An 8 ½-in. hole was drilled to TD with 17.0-ppg mud and frequent lost returns. Even with 17.0-ppg mud, mud showed a gradual chloride increase and high background and connection gas.

A 4,007-ft 5 ½-in., LT&C liner was run with one slim-hole centralizer per joint. Centralizers were allowed to float to facilitate reciprocation or rotation. The liner was run successfully to bottom. Mud was conditioned two complete rounds. Mud weight was not reduced because of gas and a slow high pressure saltwater sand feed-in. The liner was reciprocated while conditioning.

The liner was cemented with 30 bbl of 17.0-ppg spacer followed by 630 sacks of anti-gas-migration cement mixed at 17.5 ppg. The liner was rotated at 50 rpm after the cement began filling the annulus. Cement was pumped at a high rate of 6 bpm because of the large annulus.

Since the zone of interest was a gas sand, no effort was made to get cement on top of the liner in the event the anti-gas-migration cement did not work. This would facilitate a liner top squeeze with anti-gas-migration cement, if needed. There was no annular gas flow, and the liner top was squeezed with 30 bbl of water followed by 300 sacks of low-water-loss cement pumped in place below the squeeze packer at 8 bpm. Cement was displaced to 8,393 ft, or 100 ft above liner top.

Breakdown pressure before squeezing the overlap was only 50 psi with 17.0 ppg mud. Final SI squeeze pressure was 1,300 psi as a 2.500 partial water cushion was utilized to assure that cement would stay in place when pumping stopped. The liner top was successfully tested both positively to an EMW of 19.0 ppg and negatively to an EMW of 9.0 ppg. The bond log confirmed a satisfactory job. Estimated displacement efficiency to the top of the cement was estimated at 81%.

Case 3: *Production Liner, Cameron Parish, Louisiana.*

Ashland Exploration's Sweetlake Land and Oil Co. No. 2 developed a sand-control problem that collapsed its 5½-in liner. A window was cut in the 7 5/8-in. liner set at 12,225 ft from an anchored whipstock with its top at 11,944 ft. A 6 ½-in. hole was drilled to 12,460 ft. with 16.7-ppg mud. A packed hole assembly was used to ensure the replacement liner would to through the window and into the 6 ½-in. hole.

A 729-ft, 5-in., LT&C liner was run with one slim hole cetralizer per joint, which were allowed to float between collars. Four seal rings of deformable rubber were run in the overlap area to allow use of a 9.0-ppg brine packer fluid, which would cause the liner to contract.

Liner and centralizers were run slowly through the window and 6 ½-in. hole to 12,460 ft. with no problems. Centralizers did not bunch up, as many have claimed they will do. Mud was conditioned while reciprocation the liner. Mud weight was cut from 16.7 to 16.5 ppg to lower equivalent circulating density and improve chances for circulating cement on the liner top.

The cement job began with 38 bbl of 16.5-ppg spacer. After batch mixing 67 of the 155 sacks of cement on location to 17.2 ppg, a P-tank valve twisted off and the remaining 88 sacks could not be mixed. Because the liner might stick while waiting on more cement, the job proceeded with the 67 sacks mixed.

When cement started to fill the annulus, the liner was rotated at 40 rpm. Cement was pumped at 3 bpm. Due to insufficient cement being mixed, it was not circulated on top of the liner.

The liner top was squeezed with 150 sacks of low-water-loss cement, and then tested to an EMW of 18.6 ppg and 9.0 ppg, respectively. The 16.5-ppg mud was replaced with 9.0-ppg brine. No gas was detected from the 5-in. liner top, and no squeezes were needed across the pay despite only 5 min of contact time. The bond log again confirmed a good job. Estimated displacement efficiency across the payzone was 95 to 98%.

Case 4: *Drilling Liner, Wharton County, Texas.*

Ashland Exploration drilled 8 ½-in. hole in its R. L. Fields No.1 to 11,154 ft with 16.5 ppg inhibited water base polymer mud. A "packed pendulum"[29] with stabilizers 66 ft and 80 ft above the bit was used to control deviation. Thus, only the bottom 66 ft of hole required reaming with a short pony drill collar above the near-bit stabilizer.

After logging, the BHA was modified to have a near-bit stabilizer, pony drill collar and another stabilizer 9 ft above the bit. It again was considered imperative that a packed hole assembly be used to ensure getting a 7 5/8-in. FJ liner with centralizers to bottom. A four-arm dipmeter showed hole was nearly gauge. The bottom 93 ft was reamed with the packed hole assembly in case of hole spiralling due to drilling with a pendulum hookup.

A string of 9 5/8-in. intermediate pipe was set at 7,589 ft. A 3,855-ft, 7 5/8-in., 39-ppf P-110 FJ liner with one slim-hole centralizer per joint, free to float between slip type stop collars, was used. The hole began taking mud when the liner was at 9,100 ft. The hole was kept filled with water on the backside, while running the liner. Fill was washed from 11,146 to 11,154 ft. Circulation was started with partial returns, then increased to full returns by rapidly picking up the liner and swabbing the hole. Full returns would not have been achieved had the liner been hung off before cementing. Mud was conditioned for two complete circulation to minimize rhelolgical properties.

The liner was reciprocated to help displace all dehydrated mud while conditioning, and then was cemented with 30 bbl of 16.6-ppg spacer and 450 sacks of batch-mixed low-water-loss cement mixed at 16.8 ppg. Full returns occurred throughout the entire displacement until the final 75 bbl of mud were pumped. No cement was found on top of the liner. (This job was described in Part 4, July 1988.).

Since this was a drilling liner, and higher mud weights and temperatures were expected, it was important not to leave a large uncemented interval behind the pipe because of potential buckling. A retrievable squeeze packer was run and set at 7,047 ft to test the liner top at 7,299 ft.

The liner top had to be pressured to an EMW of 19.1 ppg to breakdown the formation. After break down, the formation bled off to an EMW of 18.1 ppg. The liner top was squeezed with 20 bbl of fresh water followed by 400 sacks of batch-mixed low-water-loss cement. Pumping rate was 7 bpm, final squeeze pressure was 1,300 psi, and SI dill pipe pressure was 1,025 psi. A large volume of cement was mixed in case the weakest formation was well below the 9 5/8-in. casing shoe to cover as much of the back side of the liner as possible with cement. Cement was displaced with 88 bbl of 16.6-ppg mud and 14 bbl of fresh water.

After eight hours WOC, pressure was bled off and the drill pipe reversed out. An 8 ½-in. bit was run and found top of cement at 7,185 ft. Firm cement was drilled to the top of the liner at 7,299 ft. Liner top an liner shoe were successfully tested to an EMW of 21.8 ppg. Because this was a drilling liner, no bond log was run.

Case 5: *Production Liner, Lake Tulare Field, Kings County, California.*

KCDC 17-9 was directionally drilled to measured TD of 13,550 ft. A string of 9 5/8-in.casing was set to 11,342 ft. and 8 ½-in. hole was drilled to 13,550 ft. Maximum angle was 14 1/2° and hole angle was gradually brought back to 2° at TD. Mud weight at TD was 10.4 ppg.

A decision was made to run a 7-in. production liner. Operators of other wells drilled in this field had never been able to rotate or reciprocate liners. All previous liners had been run without centralizers, because everyone was convinced they would keep the liner form reaching bottom. Total rounds of backlash from the drill string with 5-in. drill pipe and 6 ½-in. drill collars was eight at 40 rpm.

The authors decided to run slim hole centralizer on every joint, and, because of liner length, planned only 50% excess cement over the hole caliper. Centralizers were allowed to float between collars. A 2,686 ft. 7-in. 32-ppf, P-110, LT&C liner was run to TD. Backlash with liner in the hole was only 3 ¼ rounds at 40 rpm.

The liner was cemented with 100 bbl of 11.0 –ppg spacer followed by 650 sacks of low-water-loss cement. A large spacer was used because of liner length and the directional hole. There was concern about pumping too much cement and having it channel 2,000 or 3,000 ft above the top of the liner. It was considered prudent to use excess spacer to achieve adequate contact time across payzones and the liner overlap. The liner was rotated at 40 rpm throughout the job, and full circulation was maintained.

Due to a low mud weight and high fracture gradient at the 9 5/8 shoe, cement was reversed out at the top of the liner. About 10 bbl of cement were reversed out. Top of cement was left at 10,852 ft. Hard cement was drilled to top of the liner at 10,863 ft. (The liner top was found at 10,869 ft, or 6 ft deeper. This occurs on all liners because the drill pipe stretches while it is being run due to the added weight of liner. Once the liner was hung off, stretch in the drill pipe was reduced approximately 6 ft. This should be kept in mind when spacing out, for instance, a tie-back stinger. New pipe measurements should be obtained or stretch calculations made after liner is hung off. This is more pronounced the longer an heavier the liner is.) The liner was both positively and negatively tested to EMWs of 20.0 and 8.3 ppg, respectively, as per state regulations. A bond log was run and showed good bonding for the entire length of the liner. A test set of perforation did have to be squeeze later at 13,401 ft due to extraneous water production during a flow test. Estimated displacement efficiency was 73%.

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The authors would also like to state that we have read so much literature and talked to so many people concerning the subject matter that they realize that the manuscript does not completely constitute original thinking. Any credit not given to previous authors where credit is due is regretted and unintentional.

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ADDITIONAL INFORMATION

For more information regarding high rpm liner rotation, centralization, and primary cementation please visit our website at the bottom right corner of this page.

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