



## Liner running procedures are outlined and recommendations are given for preparing the liner for testing

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ASSUMING A USABLE HOLE has been drilled and correct equipment has been selected, as discussed in the first three installments of this series, it is now time to run and cement the liner. In this installment a recommended running procedure is given in addition to the description of an unusual phenomenon that can occur and possibly startle the rig site supervisor. Finally, preparations for testing the liner are discussed.

### LINER RUNNING PROCEDURES

The following procedure is taken from API *Bulletin D17*. The reader will note that it should be modified if the intent is to reciprocate or rotate the liner. The procedure is as follows:

1. Run drill pipe and circulate to condition hole for running liner. Temperature subs should be run on this trip if bottomhole circulating temperatures are not known. Drop hollow rabbit (drift) to check drill pipe ID for proper pump down plug clearance. On trip out of hole, accurately measure and isolate drill pipe to be used to run the liner. Tie off remaining drill pipe on other side of the racking board.

2. Run \_\_\_\_\_ ft of \_\_\_\_\_ liner with float shoe and float collar spaced \_\_\_\_\_ joints apart. Run liner plug landing collar \_\_\_\_\_ joints above float collar. Volume between float shoe and plug landing collar is \_\_\_\_\_ bbl. Sandblast joints comprising the lower 1,000 ft and upper 1,000 ft of the liner. Run thread locking compound on float equipment and bottom eight joints of liner. Pump through the bottom eight joints to be certain that float equipment is working.

3. Fill each 1,000 ft of the liner while running, if automatic fill up type equipment is not used.

4. Install liner hanger and setting tool assembly. Fill dead space (if pack-off bushing is used in lieu of liner setting cups) between liner setting tool and liner hanger assembly with inert gel to prevent solids from settling around the setting tool.

5. Run liner on \_\_\_\_\_ (size, type connection, weight, and grade) drill pipe with \_\_\_\_\_ pounds minimum over pull rating. Run in hole at 1 to 2 minutes per stand in casing and 2 to 3 minutes per stand in open hole. Circulate last joint to bottom with cement manifold installed. Shut pump down. Hang liner five feet off bottom. Release liner setting tool and leave 10,000 pounds of drill pipe weight on setting tool and liner top.

6. Circulate bottoms-up with \_\_\_\_\_ barrels per minute to achieve \_\_\_\_\_ feet per minute annular velocity (approximately equal to previous annular velocities during drilling operations).

7. Cement liner as follows: \_\_\_\_\_

8. If unable to continue circulation while cementing, due to plugging or bridging in liner and hole wall annular area, pump on annulus between drill pipe and liner to maximum \_\_\_\_\_ psi and attempt to remove bridge. Do not overpressure and fracture the formation. If unable to regain circulation, pull out of liner and reverse out any cement remaining in drill pipe.

9. Slow down pump rate just before pump down plug reaches liner wiper plug. Drill pipe capacity is \_\_\_\_\_ bbl. Watch for plug shear indication, recalculate or correct cement displacement, and continue plug displacement plus \_\_\_\_\_ bbl maximum over displacement.

10. If no indication of plug shear is apparent, pump calculated displacement volume plus \_\_\_\_\_ bbl (100% + 1 to 3%).

11. Pull out 8 to 10 drill pipe stands or above top of cement, whichever is greatest. Hold pressure on top of cement to prevent gas migration until cement sets. (Note: The authors recommend circulating out at this point for reasons described late in this article.)

12. Trip out of hole.

13. Wait-on-cement \_\_\_\_\_ hours.

14. Run \_\_\_\_\_ in. OD bit and drill cement to top of liner. Test liner overlap with differential test, if possible. Trip out of hole.

15. Run \_\_\_\_\_ in. OD bit or mill and drill out cement inside liner as necessary. Displace hole for further drilling. Spot perforating fluid (if in production liner) or other conditioning procedures as desired.

If reciprocation or rotation of the liner is planned, the authors recommend the following additional practices:

Generally speaking, drag<sup>19</sup> starts becoming excessive in wells whose maximum angle exceeds 35° and rotation should be planned for these holes if liner movement is desired.

▲ For wells with hole deviation 35° or less, one floating slim hole centralizer per joint is adequate to give the necessary standoff to minimize differential pressure sticking and the torque and drag reduction required.

▲ For wells with hole deviation over 35°, two floating slim hole centralizers are recommended for every other joint with one floating slim hole centralizer on the other joints.

▲ For wells with hole angles over 60°, the authors recommend two floating centralizers on every joint. However, starting forces of the centralizers should be checked when running this many centralizers. Consideration may have to be given to running drill collars on top of the liner in these type holes to provide sufficient weight to get them down. One of the authors has successfully rotated mechanically set liners in the 60° holes offshore Louisiana with this centralizer arrangement. (As discussed by Smith<sup>9</sup>, in direction holes the resistance to flow is the lowest on the upper side, but on the lower side, mud channels are formed. If during cementing on a long liner, the liner contains a rather heavy cement compared to the mud, the total load on the centralizers becomes greater than the simple weight of the liner. Since the heavy cement fills the annulus and the lighter displacing fluid is in the casing, this can cause the liner to float against the upper portion of the hole. The more centralizers that are used, the better the chances of having the liner centered in the annulus.)

The authors firmly believe that if the drill string can be turned to drill the well, a liner can be turned with less torque and drag with centralizers. Other authors report doing this successfully in horizontal and high angle wells at Prudhoe Bay, Alaska.<sup>19</sup> The authors have found that many more liners can be rotated than reciprocated and prefer rotation because of the possibility of sticking the liner off bottom (i.e., the pay zone or lost circulation zone could be left uncovered, or the mud and cement in the rathole could flip flop due to density differences and ruin the liner shoe job). Liner reciprocation also surges and swabs the hole while moving up and down. The liner could also become stuck while going down, leaving it frozen in a buckled position due to compression from the slackoff weight of the workstring. The authors normally use reciprocation to help initiate circulation and on some jobs have found that by working the liner, it has been possible to reduce torque and consequently begin rotating the liner again. One last point should be mentioned: If the liner is reciprocated, then plans should be coordinated so that the float shoe is on the bottom and stays on the bottom until the spacer is all the way out of the liner and cement has started filling the annulus. Otherwise, one could end up with cement, mud, and cement in the annulus, in that order.

The authors recommend that extremely careful considerations be given to what type of float equipment is used on a liner job. With the authors' practice of conditioning the mud for at least two complete circulations before cementing, the float equipment must be the best available, especially when using high density muds or cements with silica sand as an additive. Float equipment must also be both temperature and pressure resistant. The detrimental effects of mud abrasiveness can be reduced by using "state-of-the-art" solids control systems. Percent and size of solids in the mud must be minimized. One cannot afford to have float equipment fail after cementing after cementing a liner since its failure could ruin the cement job in the liner overlap, across a pay zone, around the shoe and necessitate the drilling of cement inside of the liner because of U-tubing. The longer the liner and the greater the density difference between mud and cement, the more U-tubing there will be. For any deep, hot, high pressured, high-mud density well in which a large amount of circulating time is expected, the authors recommend that two float collars be run with the float shoe and that they be the best float equipment available. If float equipment fails on a liner job, one does not have the luxury of closing the well in at the surface to prevent U-tubing and then waiting on the cement to set. Pressure integrity requirements of float equipment may be reduced by keeping the density difference between mud, cement and spacers as low as possible.

Finally, should circulation be lost while running the liner, the annulus should immediately be filled with water as soon as possible. In addition to leading to the possibility of a well kick, when returns are lost, a falling mud column can also reduce the hydrostatic pressure enough to let shales slough, which can impede getting the liner bottom. Filling the hole with heavy mud is a waste of valuable mud and may only aggravate the problem. The same bottomhole pressure will result whether water or mud is used.<sup>38</sup> Using water enables the actions of the well to be observed sooner (whether the loss is continuing or the well has begun to flow).

The bypass area around liner hangers should be checked on wells that have the potential for losing returns or wells that have not been adequately cleaned of cuttings that could cause bridging. There is quite a diversity of liner hanger by-pass areas that should be compared. This should also include a comparison of the lengths and ODs of the tieback receptacles immediately above the hanger. Some liner hangers have been redesigned to improve the bypass area around the hanger slips, but still have as great or greater circulating restriction around the tieback receptacle. Tieback receptacles can vary in length from 9 in. to 6 ft. Long tieback receptacles with large ODs can add significantly to the equivalent circulating density or the chances of bridging off in the overlap. This is often overlooked. This difference in restriction becomes even more pronounced if the hanger is hung off before

cementing. Short tieback receptacles can be used by simply cementing the tieback string around the bottom if plans are to fracture down the casing, for instance. Cementing liners in potential lost circulation areas will be discussed later in more detail.

## PREPARATION FOR LINER TESTING

Once everything has been done to ensure a good liner cement job, the next crucial operation is to prepare for testing the liner. Often, this is not done correctly.

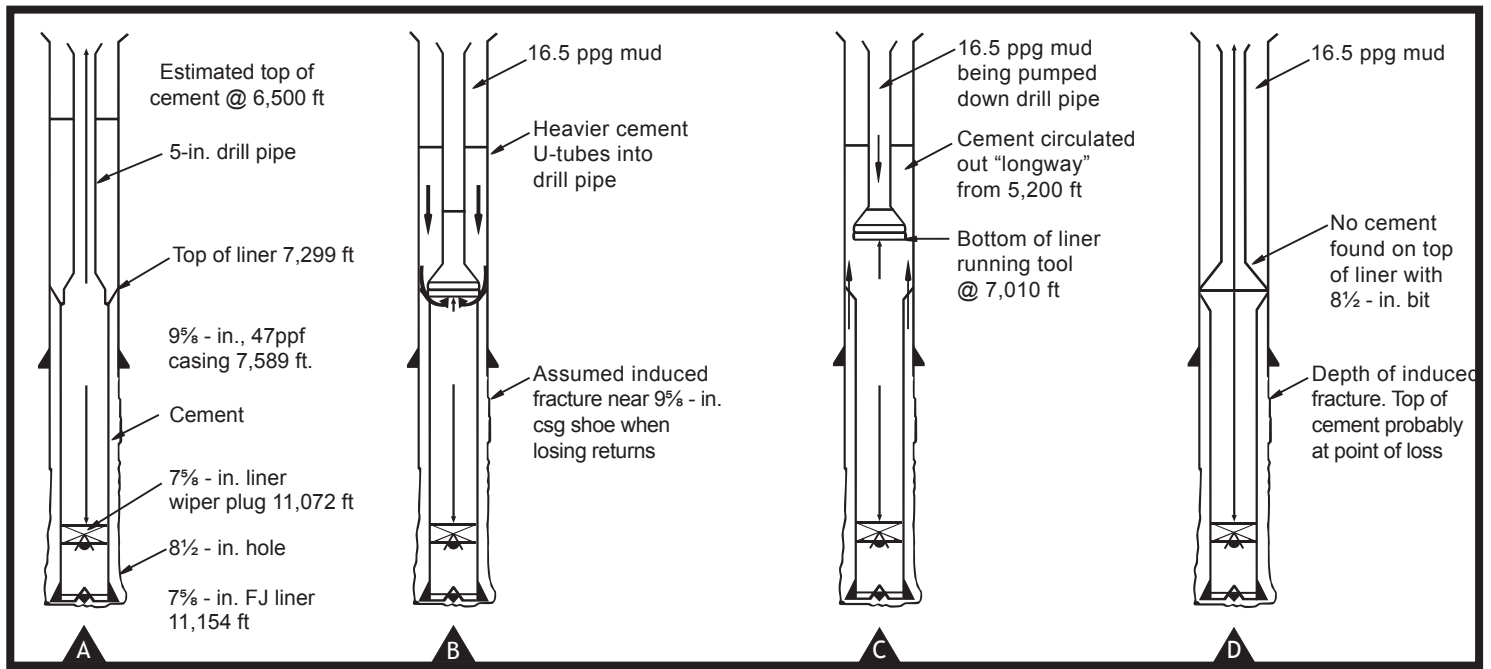
The first procedure is to check for any cement that may be on top of the liner. Indication of cement may be noted when the setting tool is pulled out of the top of the liner and flow back occurs on the drill pipe. This may result from heavy cement on the outside of the drill pipe causing the annulus hydrostatic pressure to be higher than the hydrostatic pressure of the mud inside the drill pipe. If there is a lot of cement on top of the liner, this flow back can be very strong and for a few moments, one might think that the well may be trying to come in or that the float equipment has given away. If the float equipment has given way or there is cement on top of the liner around the drill pipe, the flow should decrease and the mud in the annulus should be falling (U-tubing) until equalization occurs. If the well is trying to kick, both the drill pipe and annulus side should be trying to flow.

This same kind of situation can occur if the well is "giving back mud." This is a common occurrence in open-hole sections where mud weight approached the fracture gradient and the exposed sections are shale or tight sands. When this occurs the author feels that the hydrostatic pressure increases due to circulating initiates a fracture and the hole takes mud until the pressure loss down the face of the fracture is equal to the increase of pressure loss up the annulus. Once this balance is reached, the fracture quits extending and the hole quits taking mud. When circulation is stopped and the circulating pressure on the induced fracture is removed, the fracture closes and gives back to the mud. The lost mud volume is gotten back in full because of the zone's lack of permeability to dehydrate the mud. Dehydrated mud would not be able to flow back into the well bore and would probably help keep the fracture open. Thus, no mud would be gotten back in this scenario.

"Getting back mud" is a common occurrence in Central and South Texas and if it occurs while drilling, it can certainly occur while cementing a liner. That is why it is so important to observe the annulus if the well is flowing on the drill pipe side. If the well flows on the annulus and cement density is as heavy or heavier than the mud, then the well is probably "giving back mud" and not trying to kick. In this event, cement in the overlap area can be displaced up the hole after circulation is stopped. That is why the authors believe in "running from the cement" and then circulating out. Running from the cement a "safe" distance, closing the well in, and not circulating out is considered very risky.

On a well (Fig. 21) in Wharton County, Texas, Ashland ran a 7-5/8" in. liner from 7,299 to 11,154 ft. Mud weight was 16.6 ppg. While running the liner, complete returns were lost, but the annulus was kept full of water and it took a total of 40 bbl before the liner reached bottom, partial returns were gotten back and eventually, full returns were achieved after reducing mud weight to 16.5 ppg. The liner was cemented with 450 sacks of Class H cement, plus additives, with apparent full returns until the final 75 bbl of displacement. (Note: slurry weight of the cement was 16.8 ppg.)

The Liner was rotated at 30 rpm while cementing and hung off with its top at 7,299 ft. The drill pipe was pulled up the hole 7,010 ft. There was good backflow on the drill pipe while pulling the first two strands. The annulus was not monitored as it should have been. No one checked to see if it was flowing. Circulation



**Figure 21** - Sequence of liner job: **A** - Liner wiper plug is displaced to float collar at 11,072 ft. Returns are lost during the final 75 bbl of displacement. **B** - Liner is hung off after cementing and the drillstring is disengaged. Strong flowback is noted on the top of the liner and is equalizing due to the cement's higher density. Condition of the annulus (whether flowing or failing) was not monitored. **C** - The 5-in. drill pipe is pulled to 7,101 ft to circulate out any excess cement the "long way" (down the drill string and up the annulus). By monitoring volume of mud pumped, cement returns were noted at the surface from a calculated depth of about 5,200 ft. **D** - While going in the hole to drill cement on top of the liner, no cement was found. Apparently an induced fracture that took mud while cementing closed up and gave back the mud after cementing was completed. This inflow of mud must have displaced the cement up the hole through the liner overlap. If the drillstring had been pulled to a calculated "safe" distance above the cement top, say 6,000 ft for instance, and left there while waiting on cement to set without circulating out, the drill pipe would have been cemented in the well.

was initiated the "long way" (down the drill pipe and up the annulus) and cement returns arrived at the surface from a calculated depth of 5,200 ft. After going back in the hole to check for cement, there was none found on top of the liner. Apparently, this well had given back the mud it had taken during the final 75 bbl of displacement while cementing. This apparently moved the cement up the hole at least 5,200 ft while the drill pipe was being pulled. If the drill pipe had only been pulled part way out of the hole, say to 6,000 ft, and the well closed in while waiting on cement without circulating out, it is most certain that the drill pipe would have cemented the hole.

Anytime cement is circulated out above the liner top with full returns, and no cement is found on top of the liner, then this type problem should be suspected, especially when the mud weight is near the estimated fracture gradient and no permeability exists in the open hole where the fracture occurred. Also, it is felt that circulating out should be done the "long way" and the drill pipe rotated to ensure that cement lying on the low side of the hole is displaced by mud-to-cement drag forces while rotating. This is especially crucial in directional holes over 40°. Reversing out would require rotating the drill pipe with the annulus packed off. If there is flowback and mud in the annulus is falling, it is safe to assume that the well is not trying to kick. The authors allow some equal

ization to occur before "running from the cement" if plans are to not reverse out cement due to fear of breaking down the liner top. If well conditions permit, cement can be reversed out near the top of the liner to save time. When reversing out, it should not be done too fast because excessive pump pressures could be created that exceed the burst rating of the intermediate casing or breakdown the liner top.

Pressure can become excessive for two reasons. First of all, the hydraulic area of the work string is smaller, thus causing a higher circulating pressure loss. Secondly, the density difference between mud and cement can contribute to a higher reversing pressure because the height of the cement column is increased inside the drill pipe. For example, a 500-ft column of cement on the outside of 4 1/2-in. drill pipe in 9 5/8-in. casing will become a 1,962-ft column once it is completely reversed into the drill pipe. If the cement slurry weighs 6 ppg more than the mud, the increase in reversing pressure from this alone will be 600 psi or more. For this reason, if there is excessive backflow, the authors recommend "running from the cement" to a safe distance above the top of cement (the backflow should cease once the liner running tool is above the top of cement unless the spacer density is heavier than the mud density).

This is also why the authors recommend that the spacer be mixed at no more than 0.1 to 0.2 ppg heavier than the drilling fluid. The authors have seen no adverse affects by keeping this density difference low when using heavy muds. Others have reported the same results.<sup>25</sup> The lower the spacer density, the lower the pump rate are needed to get in turbulent flow. If lost returns are a concern, circulation again should be done the long way, if pumping time permits, to ensure that cement around the drill pipe, if any, is circulated out. The well should then be closed in and cement allowed to set for the specified period (pressure may be put on the top of the cement, but it should not be high enough to break down the formation at the intermediate casing shoe nor exceed the burst rating of the casing). This is done to keep the well from flowing while drill pipe is being pulled out of the hole. As pointed out by Goins,<sup>27</sup> gas is no respecter of the mud's hydrostatic pressure above it once it enters the wellbore. (The well is monitored while closed in. Should pressure develop, it may not necessarily mean that the well is trying to kick. Rather, it may be trapped pressure due to heat expansion. This can be checked by bleeding off small amounts (1/4 to 1/2 bbl) at a time. (Note: This should be done only after cement has had time to set. Continue to alternate the bleeding and subsequent pressure observation procedures as long as pressure continues to decrease. An absence of pressure

would indicate that the well is most likely dead.)<sup>39</sup> The gas, due to its lower density, can lubricate up through the mud and cause the well to unload mud as the gas expands near the surface. With the drill string in the hole rather than in the derrick, a kick, should one occur, can be circulated out and the well killed. Because of recent studies showing how cements may not transmit hydrostatic pressures effectively, it is considered a prudent practice to wait six to eight hours while monitoring the well before pulling the drill pipe out of the hole. After pulling out of the hole, the normal procedure is to pick up a bit and drill collars and go in the hole to look for the top of the cement using the weight indicator.

The authors consider looking for the top of cement an important operation that should be carefully planned. There have been three different jobs in which the bit and drill collars were cemented in the well because the bit was run into contaminated cement before the operator noticed any change in bit weight indicator. Attempts to break circulation through the bit failed in all three cases and the strings could not be moved. On one job, 97 rig days were spent cleaning out a drill string that was run into the cement accidentally. The authors use four techniques to guard against this eventuality:

▲ Assume a 20 to 30% displacement efficiency (cemented area divided by annular area) on all liner jobs, which gives a possible top of cement that is most probably too high, but theoretically possible (channeling was discussed earlier in this series along with possibility that when liners are hung off before cementing, packoff bushings or swab cups have been known to leak cement).

▲ With a conservatively high estimate of the top of cement, lay down enough drill pipe (during the trip out for a bit) to enable washing and reaming one joint at a time during the trip back into the hole. This keeps the bit from plugging and the drill pipe from sticking while looking for the cement top using the weight indicator only, without washing. This also allows more time for the cement to set.

▲ To avoid losing track of drill pipe measurements, use the same pipe used to run the liner for drilling cement. No drill collars are used since the cement is relatively "green" anyway, and this also minimizes any chance of pipe measurement errors. More than one liner top has been drilled on inadvertently (when thought to be good hard cement) because of confusion on drill string measurements. Once the top of cement is located, it should be drilled until it is determined to be hard. If cement is soft, drill to within 100 ft. of the liner top and then allow remaining cement to harden before it is drilled out.

▲ Wait on cement longer to allow it to harden more. One author recommends waiting on cement 18 to 24 hours, while circulating and rotating, before drilling it.<sup>14</sup>

After all cement above the liner has been drilled, a trip with a packer can be made to pressure-test the liner overlap, but a packer is not always necessary. This decision should depend on the estimated burst rating of the intermediate casing after it has been drilled through. A packer is recommended on all liner top tests in high permeability areas such as the Gulf Coast, regardless of intermediate casing burst strength.

If a packer is not used, the following problems could occur. If the intermediate casing shoe breaks down while the liner top is being tested and the mud level drops, the hydrostatic pressure of the mud column could be reduced enough to let sand (not isolated by cement) feed in from behind the liner. The amount the mud level can drop varies tremendously from area to area. This is due to a large divergence sometimes between rupture pressures and fracture extension pressures. Generally speaking, there are larger divergences in Texas and hard rock areas. The smaller diver-

gences occur in South Louisiana type environments. The larger the divergence, the more the mud level can drop.

A potential kick should not necessarily be a concern if sands behind the liner have pressures well below the mud weight being used, if long shale sections exist above the top of cement behind the liner or if the liner is run in hard rock, low-permeability areas. But if there is a gas sand near the liner top or near the bottom of the liner, but not isolated properly, and its reservoir pressure is close to mud hydrostatic pressure, the well could kick if a formation breakdown occurs and the mud level drops. If the kick is a gas sand, pressures resulting from circulating to kill the well could easily exceed intermediate casing burst pressure. If the well kicks with a packer, however, it is "bottled up" and can be killed without putting potentially serious pressures on the intermediate casing. The authors prefer that packers be used on all liner top and shoe tests. This affords testing the liner top with both positive and negative differential pressures.

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