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Circulating the hole clean: Illusion or reality?

What you see at the shakers can be deceiving.

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	GAL/MIN	AV	CV	REYNOLDS NO.
Drilling	324	154.3	253.1	3942
Circulating	546	259.1	253.1	6622

Turbulence improves hole cleaning. Most operators tend to avoid turbulent flow above the bottomhole assembly (BHA) due to a perception that it can cause massive hole erosion. However, short-term turbulence achieved by increasing the pump rate can be beneficial without inflicting wellbore damage. This method normally is not applied because small hole mud motors and measurement-while-drilling (MWD) tools generally cannot tolerate the high pump rates needed to reach turbulent flow. This leaves operators with potential hole cleaning issues, especially on high-angle and horizontal wells. To overcome these issues, operators resort to short trips, clean-out trips, bit trips, and extra sweeps. These remedies are somewhat effective, but a more significant improvement can be realized by temporarily bypassing the restrictions in the BHA.

Hole cleaning: Practice versus proof

Orders to "circulate bottoms-up to clean hole prior to running casing (or tripping)" appear on rig reports every day. The implication is that after those orders are executed, the hole will be clean. The problem is that often the hole is not clean. Drillers hit tight spots and fill while tripping, and getting casing to bottom can be challenging. The difficulty increases with hole angle to the point where work in a high-angle or horizontal section – most likely the reservoir – is performed with the expectation that a percentage of wells simply will not be completed as planned.

The bottom line is that tripping, circulating, and pumping sweeps to clean the hole is time-consuming. Drillers have learned to live with it because the alternatives – reaming, stuck pipe, casing not on bottom, etc. – only add non-productive time (NPT) and ultimately threaten their ability to complete and produce a well. So the conventional hole-cleaning practices are carried out in the oil field every day with the understanding that it is the best way to prepare the well bore for running casing.

Turbulent flow GPM

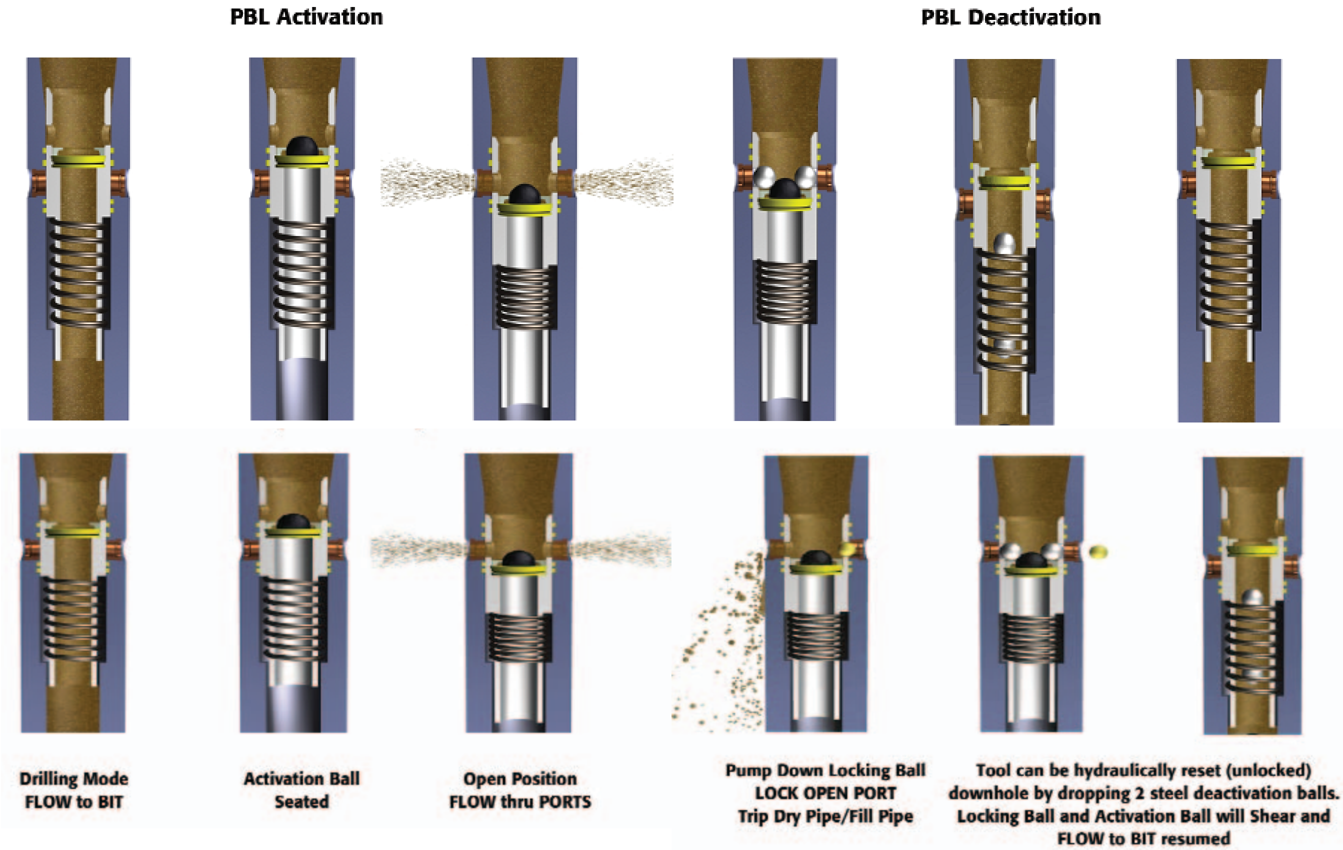
If the perception of causing hole enlargement is set aside temporarily, the idea of putting drilling fluid in turbulent flow to clean the hole makes sense. Field performance data demonstrate that short-term turbulence achieved by increasing the pump rate can be beneficial without inflicting wellbore damage. Turbulence around the BHA already is common. Depending on well depth and rate of penetration, this exposure can last for several hours as the BHA passes one particular point in the well bore. Increasing the flow rate beyond critical velocity for two bottoms-up would expose the well bore to turbulence for a small fraction of that time.

However, this method normally is not applied due to limitations in the BHA.

Bypassing BHA flow-rate limitations

A major operator on the West Coast has reduced NPT related to hole-cleaning operations by eight to 10 hours on each well by running a multi-action bypass sub (PBL tool) above the motor and MWD tools. Results obtained with the first application of this practice were significant.

The well in the Wilmington Basin was drilled to a measured depth (MD) of 8,200 ft (2,499 m, total vertical depth of 3,165 ft or 965 m), achieving an 88-degree angle prior to reaching total depth (TD). With 9⅝-in. casing set at 6,000 ft (1,829 m) and a 7-in. liner at 7,468 ft (2,276 m), it was thought during the well-planning stage that extra attention should be paid to hole cleaning after reaching TD.



Activating and de-activating of the PBL tool is shown. (Images courtesy of Downhole Devices LLC)

Annular velocities in the 9⅝-in. casing were calculated to be 154 ft/min (47 m/min). In a vertical well, this normally would be sufficient, but in the eccentric annulus of this 88-degree well, it was considered marginal at best.

Pros and cons were discussed for both increased flow rate and pumping-weighted scouring sweeps. Increased flow rate offered fewer risk-lost returns in shallow sands, especially with the ability to bypass annular restrictions around the BHA. Partial bypass tools could allow increased flow rate while drilling, but these tools were not available in the correct size. The total multicycle bypass tool was chosen as the best approach for this application. It was positioned in the drillstring to be 70 ft (21 m) into the 7-in. liner when the bit reached TD. With this placement, the entire 9⅝-in. casing could receive increased flow rate.

After reaching TD in the 6⅛-in. production interval, the operator circulated two complete bottoms-up at 324 gal/min with a standpipe pressure (SPP) of 2,422 psi. A "dribble" of solids came across two shakers. Conventional thinking would deem this a sufficient indication that the hole was clean and ready for casing operations.

The difference on this well came about because the PBL tool was in the BHA.

The operator activated the PBL tool by dropping an Ertalyte plastic ball. The flow rate was increased from 324 gal/min (2,422 psi SPP) to 546 gal/min (1,700 psi SPP). Flow rate was increased to slightly above the calculated critical velocity.

Approximately halfway through the bottoms-up cycle, all four shakers were flooded with fine (sugar sand) cuttings after the hole had been declared "clean." An estimated 15 to 20 bbl of this fine, silty material (nearly half of the cuttings volume generated in the final hole section) was removed from the cased hole.

Although the operator followed through with a predetermined cleanout trip, zero additional cuttings were seen at the shaker. Post-well analysis and discussions led to the conclusion that two bottoms-up through the bypass sub, less than an hour on these wells, would be more beneficial than a wiper trip of eight to 10 hours.

The 3½-in. liner was run to TD without incident.

A new routine

On previous wells, the operator had

encountered problems running the liner due to hole conditions related to hole cleaning. Liners have been pulled out of the hole when they failed to reach bottom. Liners have been stuck off bottom, requiring either a smaller liner than designed or sidetrack operations.

Due to the success of this well, the PBL tool now is more widely used by the operator in California as an efficient way to prepare the highly directional and horizontal wells for completion. In addition to enhancing the odds of a successful operation, the average savings of eight to 10 hours rig time has conservatively lowered overall well costs by US $20,000 to $25,000/ well and enhanced the probability of successful completion operations.

The ability to divert the flow through the PBL tool has helped minimize or eliminate time spent on other methods such as tripping and sweep regimes. By eliminating sweeps, the need to manage the sweep volume when it returns to the surface (i.e., dilution, isolation, or disposal) also has been eliminated. Although wiper trips could continue to be used for confirmation in the short term, eventually, as confidence grows in applying turbulence to the hole-cleaning process, wiper trips could be deemed unnecessary. E&P

How to know when the well bore is clean

Monitoring the shaker – One traditional method of validating a "clean" well bore is monitoring returns at the shaker. No one can justify circulating indefinitely, so output at the shakers is linked to a predetermined number of circulations. When the volume of cuttings coming across the screens decreases to the acceptable level within the prescribed period of circulation time, many drillers are satisfied that the well bore is ready for the next operation. However, accounting for silt beds and cuttings buildup left behind on the low side of the hole is tricky. Logic and physics dictate that these beds always accumulate and are hard to dislodge.

In addition, trying to circulate and "clean the hole" with the mud motor and directional drilling assembly at the end of the drillstring automatically restricts the pump rate that can be applied. Much of the scouring force is lost in pressure drops, and increasing pipe rotation speed cannot fully overcome the deficiency. Further, many argue that if a high pump rate can be applied, it is not a prudent choice because pushing returns into turbulent flow will cause severe hole erosion and only exacerbate problems with wellbore workability.

Hydraulics modeling – Some operators attempt to address the cuttings bed problem through application of good hydraulics modeling. If the model is built with accurate data on hole size, pipe eccentricity, flow rates, mud properties, and cuttings size, then it may provide a semblance of actual downhole conditions. But if the hydraulics model can accurately address the existence and character of the cuttings beds, removal options are limited in terms of efficacy and practicality.

Sweeps – Implementing a high-density and/or high-viscosity sweep program often is the strategy under difficult hole conditions, particularly where flow rates are limited because of MWD tools and mud motors. In recent years, high-density sweeps have gained wide acceptance as an aid to bringing up settled silt and cuttings. There are rules that must be observed when running these sweeps if they are to function as intended. One of the most important rules is that pumping remain continuous from start to finish. The sweep must be allowed to make the full round trip without stopping the mud pumps.

Cleanup trip – Short trips, cleanup trips, and bit trips to remove the directional drilling equipment also are added into the operation mix. The physical effects of tripping are thought to assist in shaping up the well bore, and the intermittent circulations involved contribute to cuttings removal.