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INNOVATIONS IN DRILLING BITS TO IMPROVE ITS LIFE AND THE RATE OF PENETRATION (ROP)

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A drilling bit is the cutting or boring tool which is made up on the end of the drill string. The bit drills through the rock by scraping, chipping, gouging or grinding the rock at the bottom of the hole. Drilling fluid is circulated through passageways in the bit to remove the drilled cuttings. The drilling engineer must be aware of the drillbits design variations in order to be able to select the most appropriate bit for the formation to be drilled. The engineer must also be aware of the impact of the operating parameters on the performance of the bit. The performance of a bit is a function of several operating parameters, such as: weight on bit (WOB); rotations per minute (RPM); mud properties; and hydraulic efficiency.

There are basically three types of drilling bit. These are Drag Bits, Roller Cone Bits and Diamond Bits.

Drag bits were the first bits used in rotary drilling, but are no longer in common use. A drag bit consists of hard steel blades shaped like a fish-tail.

Roller cone bits (or rock bits) are still the most common type of bit used worldwide. The cones provide cutting action by either steel teeth or tungsten carbide inserts. Rock bits are classified as milled tooth bits or insert bits depending on the cutting surface on the cones.

Diamond bits are divided into Natural Diamond bits and Polycrystalline Diamond Compact (or PDC) bits. The cutting action of a diamond bit is achieved by scraping away the rock. Despite its high wear resistance diamond is sensitive to shock and vibration. The major disadvantage of diamond bits is their cost (sometimes 10 times more expensive than a similar sized rock bit).

The major components of PDC bit design are Cutting Material, Bit Body Material, Cutter Rake, Bit Profile, Cutter Density, Cutter Exposure, and Fluid Circulation.

- Cutting Material

Problem: PDC bit cutters were sometimes chipped during drilling due to internal stresses.

The improvement: Thermally Stable Polycrystalline - TSP - Diamond bits were introduced. These bits are more stable at higher temperatures because the cobalt binder has been removed and this removes internal stresses.

- Fluid Circulation

Removing the cuttings efficiently and cooling the bit face may be satisfied by increasing the fluid flowrate and/or the design of the water courses that run across the face of the bit.

Problem: increased fluid flow may cause excessive erosion of the face and premature bit failure.

Solving: more than three jets are generally used on a PDC bit.

New Bits Speed Drilling In Unconventional Plays:

- Rotating Cutter

Problem: With a traditional cutter, most of the cutting edge is fixed into the bit blade, which means that only a small part comes into contact with the formation. In fact, more than 60 percent of the cutter’s peripheral edge goes unused during the run. It does not seem optimal to have 360 degrees of diamond, but use only a portion of it.

Improvement: To use more, Smith Bits developed a mechanism that allows the cutter to rotate 360 degrees and suffer the most wear leads to dramatic improvements in durability. Rolling cutters have higher durability not only because they use more of the diamond edge, but also because they protect the diamond from heat.

- Conical Element

Problem: the cutter at the center of the bit cut less efficiently than the ones at the outer edge. PDC bits drill by a scraping action, and it is difficult to scrape away the middle of a formation, in part because the bit's center rotates at a slower speed than the outer edge.

Improvement: Smith Bits research showed that crushing the central part of the formation is the best way to destroy it. To achieve that goal, they developed the Stinger conical diamond element, a thick and durable feature that can be placed in the center of the bit to fracture the central part of the hole, and then crush it. The Stinger element helps to centralize the bit and improves stability. It produces larger cuttings that make formation evaluation easier. In many applications Stinger element-equipped bits have delivered much greater ROP improvements.

Bit performance:

The performance of a bit may be judged on the following criteria:

- how much footage it drilled (ft)
- how fast it drilled (ROP)
- how much it cost to run (the capital cost of the bit plus the operating costs of running it in hole) per foot of hole drilled.

Since the aim of bit selection is to achieve the lowest cost per foot of hole drilled the best method of assessing the bits' performance is the last of the above. This method is applied by calculating the cost per foot ratio, using the following equation:

$$C = \frac{C_b + (R_t + T_t)C_r,}{F}$$

where: C = overall cost per foot ($/foot),
C_b = cost of bit ($),
R_t = rotating time with bit on bottom (hrs),
T_t = round trip time (hrs),
C_r = cost of operating rig ($/hrs).

This equation can be used for post drilling analysis to compare one bit run with another in a similar well, and for real-time analysis to decide when to pull the bit. The bit should be pulled theoretically when the cost per foot is at its minimum.

References

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