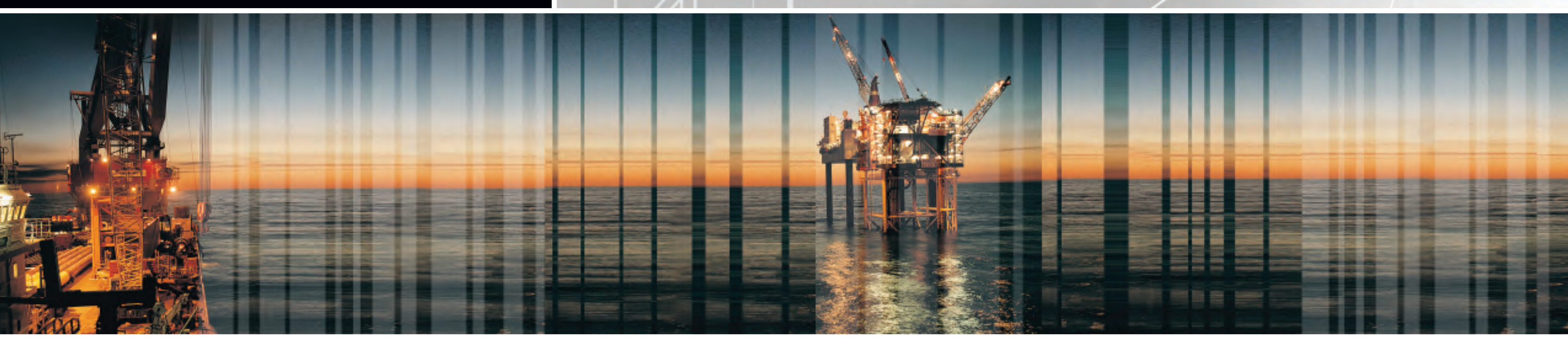
CEMENTING

Polycrystalline-Diamond-Compact (PDC) Bits Drill Out Casing-Float Equipment



WHITE PAPER

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HALLIBURTON

Fluid Systems

Business Challenge

The use of polycrystalline-diamond-compact (PDC) bits can allow operators to successfully drill out most casing-float equipment, and then continue to drill into the formation below the casing. This capability eliminates one drillstring trip because changing bits is no longer necessary. The elimination of a bit trip, particularly offshore, could save the operator several thousand dollars in rig time.

The performance of diamond cutting elements is well documented. The success of diamond technology led to the development of PDC bits. Helms et al. presented PDC technology and tests of the bits conducted at Halliburton, Duncan, Oklahoma.[1]

Bit Design

PDC bits have many sintered-polycrystalline-diamond studs on a single-piece body. Typically, 25 to 75 studs are found on a PDC bit, but the number varies with bit size. Normally, each stud is 0.5-in. in diameter, but larger studs are available.

To make a PDC bit, a wafer of sintered diamond 0.025 to 0.030 in. thick is formed onto a 0.115 to 0.140-in. substrate of tungsten carbide. Each wafer is then brazed onto either a tungsten-carbide stud or cylinder, which is then brazed or pressed into a steel or tungsten-carbide matrix body.

The structure of PDC bits can be described by the following terminology:

- Bit profile describes the geometric surface that contacts the formation. Profile types include concave, convex, stepped, full round, long taper, short taper, and parabolic.
- Cutter density refers to the number of cutters per unit area of bit diameter.

- Cutter placement describes the location of each cutter on the bit face. Each cutter is located on a separate diameter to provide redundancy such that in a single revolution, 100% of the cutters come in contact with the formation.
- Cutter exposure relates to the distance from the cutting edge of the stud to the body of the bit.

Bit hydraulics characteristics are extremely important because debris sheared away by the bit must be flushed out. If cuttings are left behind in the wellbore, the effectiveness of the bit is diminished. To aid in the flushing of debris, gauge reliefs or junk slots are often cut into the side of the bit body. Nozzles are required to provide turbulent jet flow through the bit to keep the cutting area clean.

Benefits

Several benefits can be derived from use of PDC bits for drilling out casing-float equipment.

Performance

PDC bits typically penetrate rock more quickly than conventional roller-cone bits. This increase in penetration rate is a function of the mechanism for rock failure. Conventional roller-cone bits crush the rock and rely on hydraulics to flush the debris from the wellbore. PDC bits, however, shear the rock with the diamond layer on each stud.

The structure of PDC bits allows them to be tailored to a given formation. Formation types suited to the use of PDC bits range from soft, sticky formations (IADC Code 111) to medium-hard formations (IADC Code 517). Most PDC bit manufacturers "customize" the design of PDC bits used in a particular well. This design customization provides maximum formation penetration at the lowest cost per foot (CPF).

Cost

Of great interest to the driller is the cost per foot of hole drilled. Because PDC bits cost up to five times more than conventional bits, the PDC bits must provide outstanding performance to offset bit costs. The following equation provides a way to determine these costs:

$$CPF = \frac{BC + HRC\,(TT+DT)}{FD}$$

where CPF = cost per foot of hole drilled

BC = bit cost

HRC = hourly rig cost

TT = tripping time

DT = drilling time

FD = footage drilled

To be cost competitive, PDC bits must require fewer trips, have higher penetration rates, or drill more footage without being replaced. Drilling with PDC bits often results in a much lower CPF. It is not uncommon to use PDC bits in some sections of the hole while using conventional roller-cone bits in other sections. The optimum use of drilling bits is to produce the lowest CPF, using PDC, roller cone, or a combination of types.

PDC Testing

PDC bits were successfully tested at the Halliburton research center. Goals of the testing program were to

- Determine drillability of casing equipment using PDC bits. Floating equipment tested included some with aluminum components.
- Develop recommended procedures for drilling out casing equipment.
- Evaluate drillability of NR™ nonrotating cement plugs and float collars.

Testing was carried out at the research center’s test well. The test well has a 112-ft derrick with 140,000-lb lift

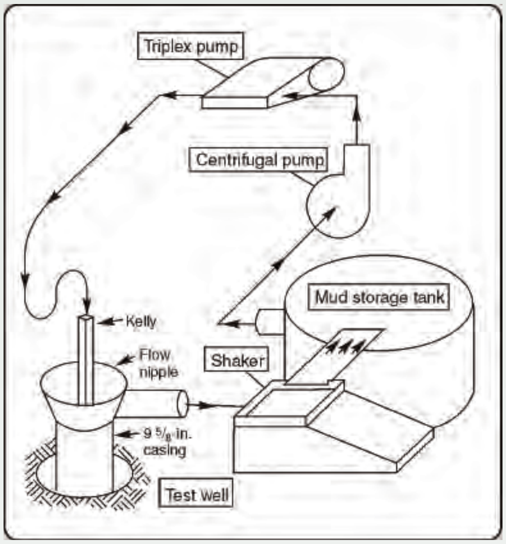

Figure 1 – Flow loop for drillout test.

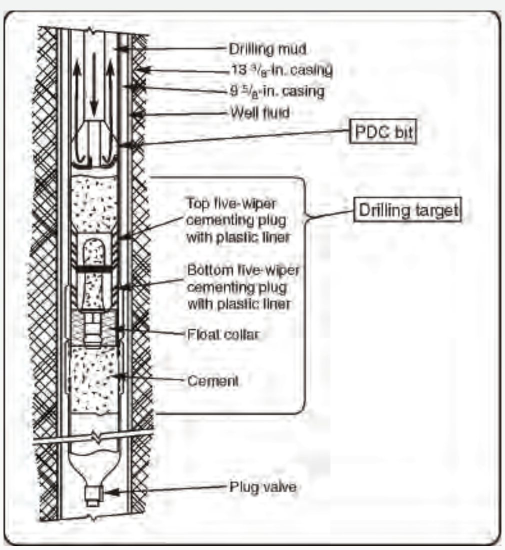

Figure 2 – Drillout test.

capacity. **Fig. 1** is a diagram of fluid flow; **Fig. 2** illustrates the drillout test setup. All testing used 12.2-lb/gal water-based mud to simulate field conditions and provide circulation that might be found in a typical drilling operation.

Three 8 3/4-in. PDC bits were used in the drillout tests. Bit 1 was a concave, or flat-bottom, bit containing forty-two 0.50-in. cutters. Bit 2 was a convex-profile bit containing more than fifty 0.50-in. cutters. Bit 3 was a semiparabolic-profile bit with sixteen 0.75-in. cutters and four 0.50-in. cutters.

The convex-profile bit is frequently used in North Sea operations. The semiparabolic-profile bit is used predominantly in soft, sticky formations, such as those found in the Gulf of Mexico.

The tests were conducted in four series:

- **Series 1** – Drill out two float collars cemented in place within 9 5/8-in. casing.
- **Series 2** – Drill out top and bottom five-wiper cementing plugs with plastic inserts, cemented in place on top of a 9 5/8-in. float collar.
- **Series 3** – Drill out top and bottom five-wiper cementing plugs with aluminum inserts, cemented in place on top of a 9 5/8-in. float collar.
- **Series 4** – Drill out NR top and bottom five-wiper cementing plugs cemented on top of the mating float collar.

During testing, weight on bit (WOB), rotational speed, and circulation rate were continuously monitored. This data, along with the bit type, determined the capability of the bits to penetrate targets.

WOB ranged from 1,000 to 6,000 lb. WOB was monitored carefully because application of excessive WOB while drilling out shoe joints can promote shoe-joint failure and damage the bit.

Rotational speed of the drillstring ranged from approximately 40 rev/min to approximately 110 rev/min, with most of the testing ranging between 60 and 70 rev/min. Too much rotational speed can also promote shoe-joint failure and interfere with the technique required to drill out the casing equipment.

The circulation rate ranged from 84 gal/min to approximately 336 gal/min. Insufficient circulation during drilling is detrimental because low circulation rates will not remove the drilled-up materials from the bit face, and may allow heat buildup that can damage the cutters.

Test Results

In Series 1, each bit was used to drill out two float collars cemented in place within 9 5/8-in. casing. Bit 1 drilled through each target in approximately 35 minutes. Bit 2 required slightly less than 25 min, and Bit 3 required only 12 min to drill through each float collar.

Series 2 and 3 tests were designed to drill out top and bottom five-wiper cementing plugs with both plastic and aluminum inserts. All tests were carried out with the plug sets cemented in place on top of a float collar. Drillout times ranged from 1 1/2 to nearly 5 hours, causing drillers to become frustrated with their inability to drill out the casing shoe joint in a timely manner. This problem was traced to rotation of the cementing plugs in relation to each other and to the floating equipment, and to insufficient cleaning of debris from the bit. The plug rotation was caused by two factors: (1) insufficient cement placed around the top plug, allowing the plug to spin freely, and (2) the aggressive nature of PDC bits, which sometimes seized the plugs and caused them to spin freely with the bit. Additionally, the debris that is allowed to accumulate around the bit can have the same effect as the spinning plug.

Although lighter weight on bit (WOB) and frequent flushing of the bit helped solve drilling problems, results indicated that aluminum-inserted cementing plugs should not be drilled out with PDC bits. Although the aluminum itself was drillable, the inserts broke into large pieces that tore free from the rubber during drilling, causing severe impact damage to the cutters-an unacceptable risk. By contrast, bit damage sustained when drilling out plastic-inserted plugs was inconsequential, and the Series 4 testing was performed successfully.

Conclusions

- Although PDC bits can outperform conventional roller-cone bits in many applications, they do have limitations.
- Because the diamond surfaces are extremely hard, they are inherently brittle. Impact with hard metals can cause major damage to the cutters.
- PDC bits are unstable when they are subjected to high temperatures. Friction can cause excessive heat buildup if the cutters are not sufficiently cooled through circulation.

These factors make PDC bit performance unsatisfactory in heterogeneous formations and for drilling floating equipment containing cast-iron flapper valves or steel springs. Use in these applications can cause excessive wear to the bit or, more likely, cause damage to the point of limiting the economic benefit of the bit.

Recommendations

Recommendations presented in this white paper will help ensure successful drillout of Halliburton cementing plugs and float equipment using PDC bits.

After a casing string is cemented in the wellbore, the shoe track or shoe joint (distance between the top of cement inside the casing and the float shoe or guide shoe) is commonly drilled out.

During the past several years, fixed-cutter bit designs have improved significantly. Technology and manufacturing processes have improved bit performance and reliability to the extent that PDC bits are being used in hard-rock drilling applications. PDC bits have also become more commonly used to drill out cementing plugs and float equipment.

The following key factors affect bit performance while drilling cementing plugs and float equipment:

- Bit style (i.e., cutter size and angle, blade layout, bit profile)
- Bit hydraulics and hole-cleaning issues (flow rate, number of blades)
- Drilling procedures (i.e., weight on bit, pump rate, rev/min)
- Target materials being drilled (rubber, cast or wrought aluminum, bronze, plastic, concrete, etc.) Note: All target materials are best drilled with fixed-cutter bits when the target itself is not allowed to rotate. Proper cementing procedures can help ensure effective placement of cement near and around the target.

Procedures for drilling NR cementing plugs and float equipment vary greatly among locations and geographical areas. Procedures differ, depending on the type of formation being drilled and bit type being used. In the case of fixed-cutter bits, more specifically PDC bits, much has been learned from operators who have tried different procedures and have developed a successful pattern.

Some lessons-learned highlights are listed:

- Apply weight on bit (WOB) of 300 to 500 lb per inch of bit diameter.
- Allow WOB to drill off before applying more weight. Sudden addition of WOB may cause the bit to stick or slip. Increased WOB is not necessarily the solution to increased penetration rate.
- Drill at 40 to 100 rev/min.
- Maintain maximum flow rate at the bit (5 to 10 gal/min per sq in. of bit area) to aid in debris removal from the bit. Insufficient hole cleaning near the bit can cause debris to build up below and around the bit, acting as a "bearing" and reducing penetration rate.
- Reciprocate the bit only if penetration stops. Reciprocate while maintaining circulation and rotational speed to help ensure proper removal of debris.

The key to successful drillout of cementing plugs and float equipment is careful attention to penetration rates. If, at any time, the penetration rate decreases, consider a change in procedure (WOB, pump rate, or rev/min).

Bibliography

1. Helms, L., Sullaway, B., and Sherrill, J.: "PDC Bits Drill Out Casing-Float Equipment." Oil & Gas J. (August 1989) 32-36.

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