Causes of wear of PDC bits and ways of improving their wear resistance

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Abstract. The scope of the paper encompasses basic factors that influence PDC bit efficiency. Feasible ways of eliminating the negatives are illustrated. The wash fluid flow in a standard bit is modeled, the resultant pattern of the bit washing is analyzed, and the recommendations are made on modification of the PDC bit design.

A rational approach to selection of a rock drilling tool ensures considerable savings of capital costs in drilling and construction of oil and gas wells, while optimization of drilling techniques promotes introduction of new types and designs of drill bits. In recent years, PDC bits increasingly gain popularity as they step up penetration rate per drill bit and cut down the trip in/out time, superseding roller cutting bits thereby [1].

When drilling in variable hardness rocks, drill bits experience with axial, radial and tangential vibrations. Under such conditions, drill bits continuously operate in percussion mode. The increment loads exerted on a drill bit increase the bit wear. Due to progressive wear of drilling tools, load per unit area of rocks lowers, which results in a decrease in the rate of penetration [2].

The key negative factors to affect drilling capability with PDC bits are wear of teeth, teeth holders and jet nozzles, reduction in bit diameter, defect of thread connections, vibration, packing and improper pattern of drill bit positioning.

Let us discuss each individual factor, starting with the most substantial influence and showing possible ways of eliminating negative impacts on drilling.

1. Wear of teeth. Among the listed above factors, this is the dominant factor for:
   —first, wear of teeth governs coverage of teeth at well bottom, which conditions efficient drilling;
   —second, wear of peripheral teeth conditions rated diameter of a drill bit;
   —third, replacement of damaged teeth is the most expensive part of repair;
   —fourth, evaluation of drilling characteristics of a drill bit consumes much time as it is necessary to examine individual teeth and, then, their ensemble, and to count the damaged teeth.

   To assume a drill bit unworkable, it is required that more than 60% of teeth are damaged. When many teeth are worn-out, drilling performance drops while rate of wear of other members of a drill bit grows until complete failure.

   From practice of drilling with drill bits, sides of a drill bit are subjected to major wear (see Figure 1a—wear of a drill bit with a diameter of 220.7 mm). Teeth arranged at different spacing along the
radius from the drill bit axis deteriorate utterly unevenly. Peripheral teeth are in the most unfavorable conditions.

![Image of drill bit wear](image)

**Figure 1.** Wear of drill bits: (a) side of a drill bit; (b) fatigue grooves due to cyclical heating and cooling.

Wear of peripheral teeth is most often represented by chippage, galling, wear of underlayer with the concomitant symptom of thermal overload. Wear of drilling teeth after cutting in variable hardness rocks is of the mixed abrasive and impact-abrasive nature. Cyclical heating and cooling of surface during operation and, consequently, alternate expansion and contraction of surface layers causes the so-called fatigue grooves (Figure 1b).

It is known that downhole fluid motors are also sources of vibration due to disbalance of rotating rotor, clearings of radial supports and distortion of rotor shaft and housing. Amplitude of transverse vibrations may reach 10 mm and above, and frequency is equal to one vibration per revolution. High-rate wear of peripheral teeth is an aftereffect of this factor, too.

2. Wear of teeth holders. Replaceability of a tooth depends not on the depreciation of the tooth but on the integrity of the tooth holder characterized by percentage of damaged surface of the holder. Accordingly, when the surface of a holder is completely covered by the tooth body, housing and alloying material, the holder is assumed unworn (Figure 2a) [3].

![Image of tooth holder wear](image)

**Figure 2.** Schematic representation of surface of teeth holders: (a) unworn holder; (b) and (c) repairable holder (surface wear from 10 to 50%); (d) unrepairable holder (surface wear more than 50%); 1—diamond plate; 2—tungsten–carbide underlayer; 3—surface of tooth holder; 4—PDC bit body; 5—hard-alloy welding.
If the damage of a tooth holder makes 1/10 (i.e. visible) to 1/2 of the overall surface area, the holder is assumed repairable as it is yet possible to fix a new tooth in it.

Figures 2b and 2c illustrate typical partial damage of surface of a tooth holder with the lost portion of the tooth body or failed alloying material that protects the holder. Exposure and damage of surface of a holder usually take place simultaneously.

When more than a half of the holder surface is damaged (see Figure 2d), the holder is assumed unrepairable as it fails to preserve initial guiding base to orient a tooth.

3. Wear of jet nozzles. During operation of a drill bit, it is necessary to control jet nozzles and the absence of erosion. Under erosion or when any jet nozzle is lost, pressure difference in the bit reduces, washing fluid flow rate slows down and quality of cleaning of the drill bit and the well bottom deteriorates. Erosion of bit housing is understood as generation of holes in the housing, aside from drilling-bit fluid discharge ports.

The loss of a jet nozzle is sufficient to assume the jet nozzle unit is in want of repair. When a jet nozzle is come down, or initial diameter of the jet nozzle hole is eroded by 4 mm and more, the jet nozzle unit is unrepairable.

4. Reduction in bit diameter. This factor is an aftereffect of wear of peripheral teeth, which results in the gage loss of a drill well, and is to be controlled using a set of two specially manufactured gage rings with the diameters smaller than the rated diameter of a drill bit. Diameters of the first and second gage rings are selected based on geological features of the drill log, rigidity of the bottom of the drill-stem assembly and process steps scheduled for implementation in the course of drilling.

If a drill bit does not get through gage ring 1, the drill bit is assumed unreduced in diameter.

Passage through gage ring 1 and nonpassage through gage ring 2 defines the range of repairable drill bits. In this case, the operation of a drill bit is stopped, wear of other elements of the drill bit is evaluated and, based on this, a decision on the drill bit repair or disposal is made.

If a drill bit passes through gage ring 2, the drill bit gage loss is assumed and the drill bit is unrepairable.

5. Wear of thread connection. Any damage of thread, preventing from screwing a drill bit, is a sufficient condition for assuming the thread connection inappropriate for further operation of the drill bit.

6. Vibration. Vibration complicates the control over technical data of drilling, optimal drilling mode is failed and power consumed to rotate the drilling assembly sharply grows [2].

Among possible approaches to combating vibration, the most promising way seems to be installation of vibration dampers at the bottom of the drill stem assembly. It is highly important to stabilize a drill assembly during operation of drill bits, as this governs the drilling efficiency in variable hardness rocks and stabilization can ensure even loading of all teeth. Currently, bottomhole bumpers enjoy no wide application, and no studies have been carried out to examine PDC bit operation under conditions of vibration damping. In the East Siberia, bottomhole vibration dampers are the mandatory requirement for operation of drill bits. This method of damping vibrations is a promising technique to be used in drilling and construction of oil and gas wells in other regions of Russia. Also, it is possible to suppress vibration of a drill stem assembly and to enhance efficiency of drilling in variable hardness rocks though installation of a hydraulic pulsator in the drill bit body.

The hydraulic pulsator placed in a counterbore in the drill bit body periodically catches drilling fluid in the drill bit cavity, pressure in the drill bit cavity grows, and opening of the cavity initiates an impulse in the drilling fluid flow. This allows transmission of impulses of axial dynamic loads directly to the drill bit with avoiding absorbing effect of intermediate units, including a downhole drilling motor. When a damper is installed between a drill bit and a downhole drilling motor, the impact exerted by the axial dynamic loads on the drilling motor is considerably reduced, which extends the motor service life. At the same time, transmission of high axial dynamic forces to a drill bit at the seam rpm enhances the cutting force of the drill bit, especially the vertical force component. Thus and so, with the increased cutting force, the rate of penetration grows.
7. Packing. This obstacle appears in PDC drilling in argillaceous deposits. As a consequence of adhesion of clay to metal surface of a drill bit, packing can coat entire drill bit, which totally blocks drilling (refer to Figure 3).

Packing is mostly prevented by modification of drilling mode (reduction in axial load on drill bit, increase in flow rate) or design of drilling tool. Also, it is possible to use drilling fluids with the improved antiadhesion characteristics.

In case of sticking of a drill bit, a borer has to try to remove a ball from a drill bit in the hole, or to move up an untreated drill bit.

There are some case histories when penetration stopped right after a drill bit was run down a well. It is thought that the cause of this is PDC bit packing as a result of its contact with the well walls. The chief problem in this case is chocking of space between blades with compacted rocks.

![Figure 3. General view of a PDC bit with clay packing.](image)

In this case, a drill bit is elevated above the well bottom by 15–20 cm, and pumps are switched on/off a few times. It is thought that fluid repelled from the bottom breaks down the packing by means of hydraulic impact; however, this method is not always effective in cleaning a drill bit [4].

8. Pattern of drill bit positioning. There single-station, many-station and multi-position drill bits.

In case of a single station PDC drill bit, each tooth of the bit is given unique radial position determined relative to the central bit axis outward in the direction of the bit diameter. One of the common methods of single-station drill bit arrangement is placement of teeth at the intersections of the spiral line, drawn from the drill bit axis, and each blade. In this case, each intersection point of the spiral and blades occurs at different radial distance from the drill bit axis.

Single-station PDC drill bits demonstrate higher rate of penetration; however, when a tooth is damaged or lost, wear of the nearest radial teeth quickens. This results in early failure of a drill bit.

In many-station drill bits (“backup tooth” or “accompanying tooth” schemes), teeth are actuated in groups of two or more teeth, and teeth in a group are placed at the same radial distance from the drill bit axis. In view of smaller area, fewer blades can be arranged at the drill bit end, and not every tooth can be a member of a group arranged along the same radius; and still, most of teeth belong in the same group. A typical pattern of teeth is when grouped teeth (along the same radius) are arranged, e.g., on opposite blades.

Multi-position PDC drill bits are, as a rule, highly wear resistant as against single-station bits but exhibit slower penetration rates [5].

A multi-position drill bit is better balanced as compared with the single- and many-station bits. With the closely spaced backup secondary blades in combination with the equivalent arrangement of backup teeth along the contour of a drill bit, the backup teeth cut minimum amount of rock per each rotation of the drill bit. Single-station primary teeth on the primary blades fulfill much work, and the backup teeth on the secondary blades only cut groove bottom after the primary blade.

All factors discussed above exercise considerable influence on efficiency and service life of PDC drill bits. Furthermore, reduction in wear of members of a drill bit is feasible through correct operation
of mud system, which is intended to ensure both timely removal of chipping and prompt and efficient cooling of cutting tools.

It is known that drilling temperature at the cutting tool and rock contact may reach 1000°C, and inefficient cooling can cause critical wear of diamond-bearing cutting layer and underlayer, and can induce fall of teeth from holders.

Efficient cooling of cutting tools requires that a mud system ensures required and sufficient washing fluid flow rate and high flow rate along active faces of blades.

Aimed at adjustment of drill bit design and determination of rational geometry with a view to enhancing drilling efficiency, the process of flushing-out of well bottom has been modeled using SolidWorks Flow Simulation [6].

After the analysis of the model of washing fluid flow in a drill bit (Figure 4), it has been concluded that:

1. The mud system does not ensure direction flow of washing fluid (Figure 4, positions 1 and 4), which results in poor cleaning of well bottom, in probability of extra interaction with chipping and, eventually, increased wear of cutting tools.

2. The inter-blade space has an expanding cross-section, which conduces to speed drop (Figure 4, position 4) and turbulence (Figure 4, position 1) of washing fluid in the inter-blade space, and causes packing.

3. The washing fluid flow rate is high along the well walls (Figure 4, position 5) but is lower along the active faces of blades (Figure 4, positions 2 and 6), which ends with insufficient cooling of cutting tools.

4. The main flow of washing fluid (Figure 4, position 3) is directed to the well bottom, along the inactive face of the blade, which is worsens heat withdrawal.

Elimination of the listed shortcomings requires to increase washing fluid velocity along the active faces of blades of PDC drill bits. Efficiency of cooling of cutting elements will grow in this case, and wear of cutting tools will abate as a result, which will extend service life of drill bits. It is possible to

![Figure 4. Velocity of washing fluid at the flow rate of 30 l/min.](image)
speed-up washing fluid flow at the periphery of the inter-blade space by ensuring uniform cross-section of the inter-blade space to prevent packing and to improve removal of chippings.

References

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