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# Oil well drill bit failure during pull out: Redesign to reduce its consequences

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ABSTRACT

A drill bit with polycrystalline diamond (PDC) inserts lost one of its three blades when operating in an oil well, leading to a costly failure. Operating conditions and associated stresses were analyzed, bit core material in the failure and adjacent areas was analyzed and tested, and fracture surfaces identified.

Base material is a Ni-Cu-Mn matrix with tungsten carbide precipitates. Fracture surfaces showed cleavage planes and loss of particles, indicating a brittle fracture. Microstructures and hardness were similar in all analyzed regions, and according to specifications.

The symmetry and characteristics of the fracture surfaces allow defining that the loads that caused the failure were not applied during the drilling operation. The blade broke apart due to a downward force applied at its base. Finite elements numerical modeling allowed pinpointing a specific moment in the pulling operation, in which a 28 ton overpull force was recorded, as the immediate operational event that caused the failure.

Operating procedures that reduce the likelihood and amplitude of impact loads, are difficult to implement; more promising is the alternative for a redesign of the drill bit. Commercial designs focus mostly on the efficiency of the cutting cycle; blade geometry can be also optimized to take into account the pull out conditions. The most efficient redesign for this specific drill bit model relies in a re-machining of the blade base, so that a large overpull load would crack a small sector, on which a PDC insert is located. In this gecko-tail type solution, only one insert would be lost, preserving the integrity of the rest of the drill-bit. Subsequent repair would involve standard thermal spray base metal techniques, including reconstitution and brazing of a new insert.

## 1. Introduction

Deep wells for oil and gas production are drilled using a drill string to create boreholes. The main components of an industrial oil-well drill string are the top rotary mechanism (rotary table or top drive), drill pipes and bottom hole assembly (BHA). To turn the drill bit, the entire drill string is rotated at the surface using the top rotary mechanism. The segmented drill pipes are joined together to connect the top rotary mechanism with the BHA. The dynamics of drill strings has complex characteristics such as coupled axial, lateral and torsional vibrations as well as hysteretic downhole friction.

Rotary drills exert a combination of pressure, rotational speed and lavage, which have a decisive influence to achieve maximum drilling speed with minimum cost. Key to achieving maximum productivity and overall streamlining of the drilling is the use of PDC

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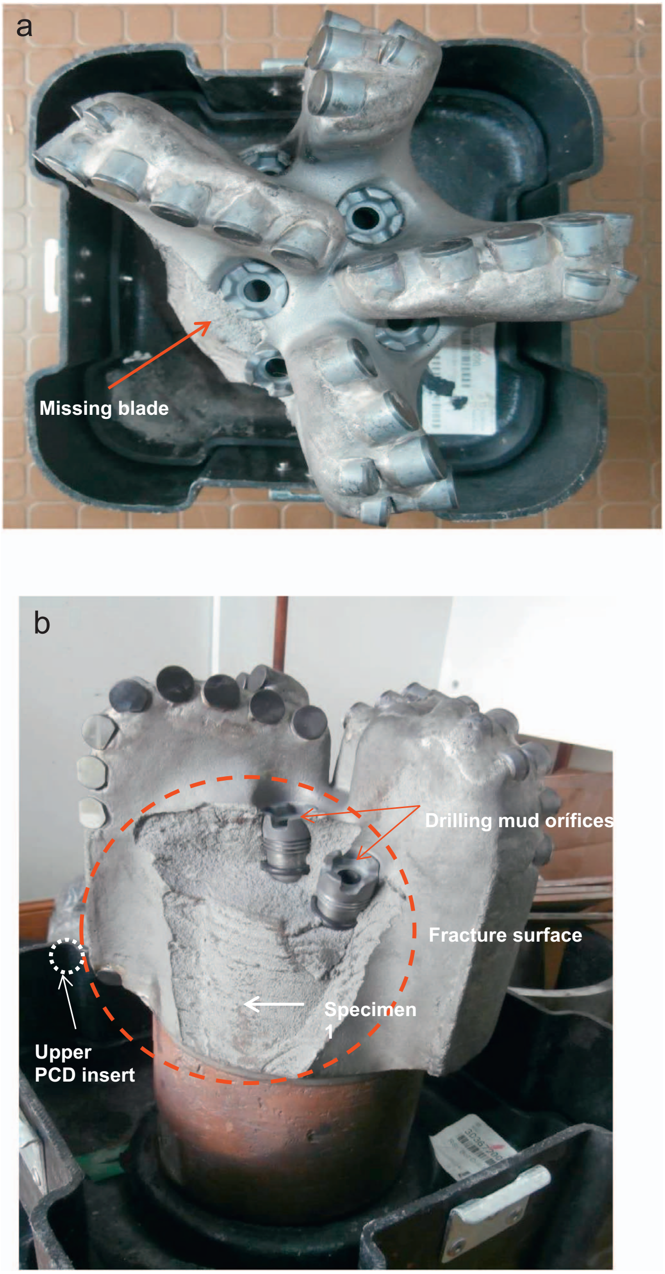


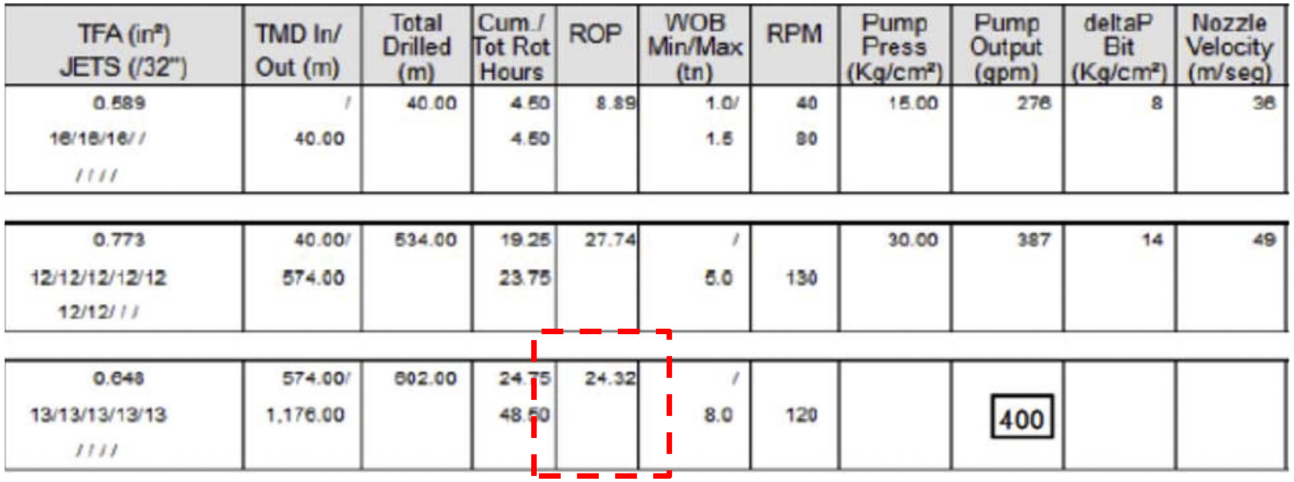
**Fig. 1.** (a,b) Failed 8,5″ oil well drill bit.

inserts, strategically shaped and placed around the drill bit, in order to optimize drilling efficiency [1]. Polycrystalline-diamond-compact (PDC) cutter technology includes a new generation of hybrid bits that is based on proven PDC-bit designs with rolling cutters on the periphery of the bit.

These are now preferred for many applications over conventional PDC and roller-cone bits, especially to drill shale and other plastically behaving formations, and in directional drilling. The penetration rate of a hybrid bit responds linearly to rotary speed, while torsional oscillations are lower and stick/slip is reduced. Lavage is accomplished with a suitable drilling fluid, most usually water-based, although sometimes gas is used. Gas drilling has some advantages in preventing circulation losses, faster drilling speeds and reservoir protection [2]. Particular rock conditions such as hard carbonates with chert inclusions [3] and conglomerates [4], and Interbedded formations [5] have led to recurring failures and other drilling difficulties, and therefore to continuous improvements in drill bit designs [6].

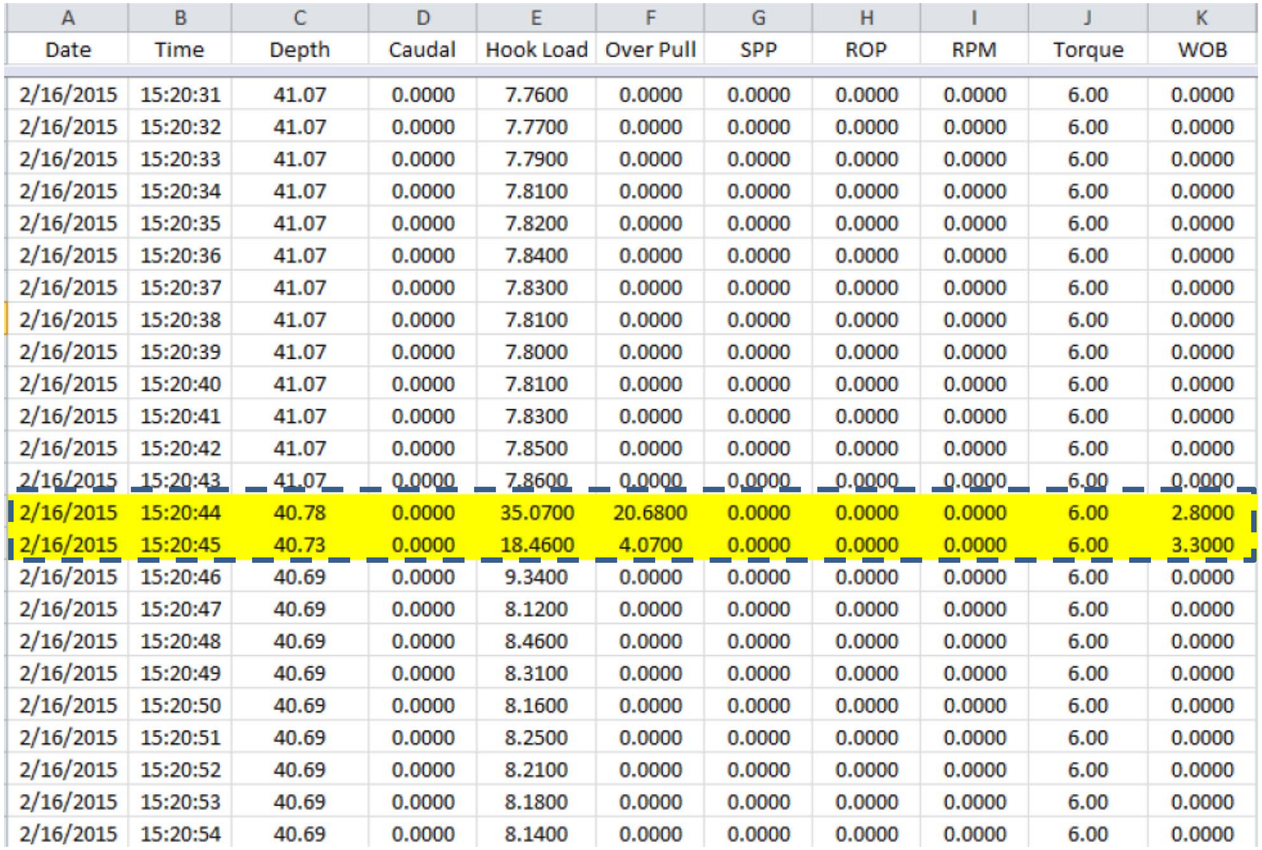
An 8,5″ oil well drill bit with PDC inserts lost one of its five blades when operating in an oil well, leading to a costly failure (Fig. 1). The drill bit is built around a central tubular, into which a strong metallic body is cast and machined. This body can have

**Table 1**
Field parameters during drilling.



| TFA (in²) JETS (/32") | TMD In/ Out (m) | Total Drilled (m) | Cum./ Tot Rot Hours | ROP | WOB Min/Max (tn) | RPM | Pump Press (Kg/cm²) | Pump Output (gpm) | deltaP Bit (Kg/cm²) | Nozzle Velocity (m/seg) |
|---|---|---|---|---|---|---|---|---|---|---|
| 0.589<br>16/16/16/ /<br>/ / / / | /<br>40.00 | 40.00 | 4.50<br>4.50 | 8.89 | 1.0/<br>1.5 | 40<br>80 | 15.00 | 276 | 8 | 36 |
| 0.773<br>12/12/12/12/12<br>12/12/ / / | 40.00/<br>574.00 | 534.00 | 19.25<br>23.75 | 27.74 | /<br>5.0 | 130 | 30.00 | 387 | 14 | 49 |
| 0.648<br>13/13/13/13/13<br>/ / / / | 574.00/<br>1,176.00 | 602.00 | 24.75<br>48.50 | 24.32 | /<br>8.0 | 120 |  | 400 |  |  |

**Table 2**
Field parameters during pulling over (POOH, drill bit retrieval).



| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| Date | Time | Depth | Caudal | Hook Load | Over Pull | SPP | ROP | RPM | Torque | WOB |
| 2/16/2015 | 15:20:31 | 41.07 | 0.0000 | 7.7600 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:32 | 41.07 | 0.0000 | 7.7700 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:33 | 41.07 | 0.0000 | 7.7900 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:34 | 41.07 | 0.0000 | 7.8100 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:35 | 41.07 | 0.0000 | 7.8200 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:36 | 41.07 | 0.0000 | 7.8400 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:37 | 41.07 | 0.0000 | 7.8300 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:38 | 41.07 | 0.0000 | 7.8100 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:39 | 41.07 | 0.0000 | 7.8000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:40 | 41.07 | 0.0000 | 7.8100 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:41 | 41.07 | 0.0000 | 7.8300 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:42 | 41.07 | 0.0000 | 7.8500 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:43 | 41.07 | 0.0000 | 7.8600 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:44 | 40.78 | 0.0000 | 35.0700 | 20.6800 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 2.8000 |
| 2/16/2015 | 15:20:45 | 40.73 | 0.0000 | 18.4600 | 4.0700 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 3.3000 |
| 2/16/2015 | 15:20:46 | 40.69 | 0.0000 | 9.3400 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:47 | 40.69 | 0.0000 | 8.1200 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:48 | 40.69 | 0.0000 | 8.4600 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:49 | 40.69 | 0.0000 | 8.3100 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:50 | 40.69 | 0.0000 | 8.1600 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:51 | 40.69 | 0.0000 | 8.2500 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:52 | 40.69 | 0.0000 | 8.2100 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:53 | 40.69 | 0.0000 | 8.1800 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |
| 2/16/2015 | 15:20:54 | 40.69 | 0.0000 | 8.1400 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6.00 | 0.0000 |

different shapes, according to the type of service and technology chosen. In our case, it has five blades.

The contractor performing the drill reported that at the time of the rupture the entire section was drilled with good rate of penetration (ROP) and that there were no symptoms of any failure. Table 1 summarizes field data. We can see that the average ROP was almost 25 m/h, mostly constant, which could not have been achieved with a drill bit with a missing blade. On the other hand, Table 2 shows that during the retreat of the string (POOH), an overload (overpull) was detected at 40.78 m and the hook load (load reported at the top of the string) increased from 7.86 ton to 35.07 ton almost instantly.

With this evidence, the contractor concluded that the failure may not have happened during drilling, but rather during the withdrawal of the tool. The operator, however, was not convinced; such an event would have been a very infrequent situation. Taking into account the cost associated with the incident, it was decided to carry out a failure analysis in order to determine whether the mentioned hypothesis was physically possible.

Drill pipe failures, due mostly to fatigue and related mechanical damage, sometimes also influenced by corrosion and abrasion, are the most common reasons for drilling failures. Maximum cyclic stresses occur at the bottom of the drill string. Failure history and mechanical analyses show that the drill collar thread is the most prone region for multi-axial fatigue failure in of standard API drill connections [7]. Improved shoulder designs aim to improve fatigue life of drill strings. On the operative side, reducing the amplitude of cyclic bending stresses by controlling abrupt changes in well bore direction (doglegs) can be difficult in complex, layered and fractured soils. Broken formations and strong water-sensitive shale formations are particularly prone to this type of accidents [8].

Failures of drill bits can be classified into several categories; the most common is severe abrasion of during drilling complex rock layers. This type of failure results in increasing consumption of bits, delays and eventually borehole instability. Seldom of this type of failure results in a catastrophic accident [9]. Thermal damage affects the wear performance of PDC inserts. Excessive drilling load (as in drill sticking) is the primary threat to bit failure.

Stick–slip vibrations occurs in drilling deep wells when the borehole assembly (BHA) is momentarily caught by the bit-rock interaction friction torque (i.e., stick) and then suddenly released (i.e., slip). The sudden release of stored potential energy in the flexible drill strings during the slip phase can vary the rotational speed of the BHA. Further, the severe torsional vibrations in drill strings result in large centrifugal accelerations that excite the coupled lateral vibrations, which can make the drill string hit the borehole wall. These undesired torsional and lateral vibrations result in excessive bit wear, premature tool failures and poor drilling rates [10]. The shedding of diamonds from the cutting rim and related premature wear, destruction of the entire drilling tool results in inefficient drilling and high cost of labor and drilling tools [11].

## 2. Experimental procedure

Experimental testing was carried out in samples or specimens taken from (Fig. 1b):

1. Fracture zone: adjacent to the fracture, at different possible initiation sites.
2. Base material: isolated near – surface zones, far away from the fracture.

Results from EDS chemical analyses and Vickers hardness testing [12] are shown in Table 3. Although matrix compositions differ, both matrix materials are Ni–Cu-Mn alloys, with similar mechanical strength. Composition of tungsten carbides is analogous in both areas, also with similar hardness.

Results from the metallographic analyses of samples 1 and 2 as per ASTM E 3 [13] are depicted in Fig. 2. The drill bit material is a matrix metal (binder) plus a dispersion of tungsten carbides; microstructures are similar in both samples. This design gives a material with high wear resistance but poor impact toughness. An alternative frequently used is a fully metallic base material, which is usually less wear-resistant but tougher.

Visual observations with stereoscopic magnifying glass of the fracture surface are reproduced in Fig. 3 and Fig. 4. Fracture surface morphology gives valuable information:

- The edges of the fracture surfaces have sharp, faceted characteristics. The smooth, curved central surface in Fig. 3 corresponds to

**Table 3**
Chemical composition and Vickers hardness (HV) of matrix metal and carbides.

| | Fracture zone | Base material |
|---|---|---|
| Matrix | | |
| %Ni | 40.76 | 13.46 |
| %Cu | 35.72 | 53.50 |
| %Mn | 17.59 | 23.84 |
| %Zn | 5.93 | 9.20 |
| HV hardness | 358 | 320 |
| Carbides | | |
| %C | 5.96 | 5.83 |
| %W | 94.04 | 94.17 |
| HV hardness | 1678 | 1708 |

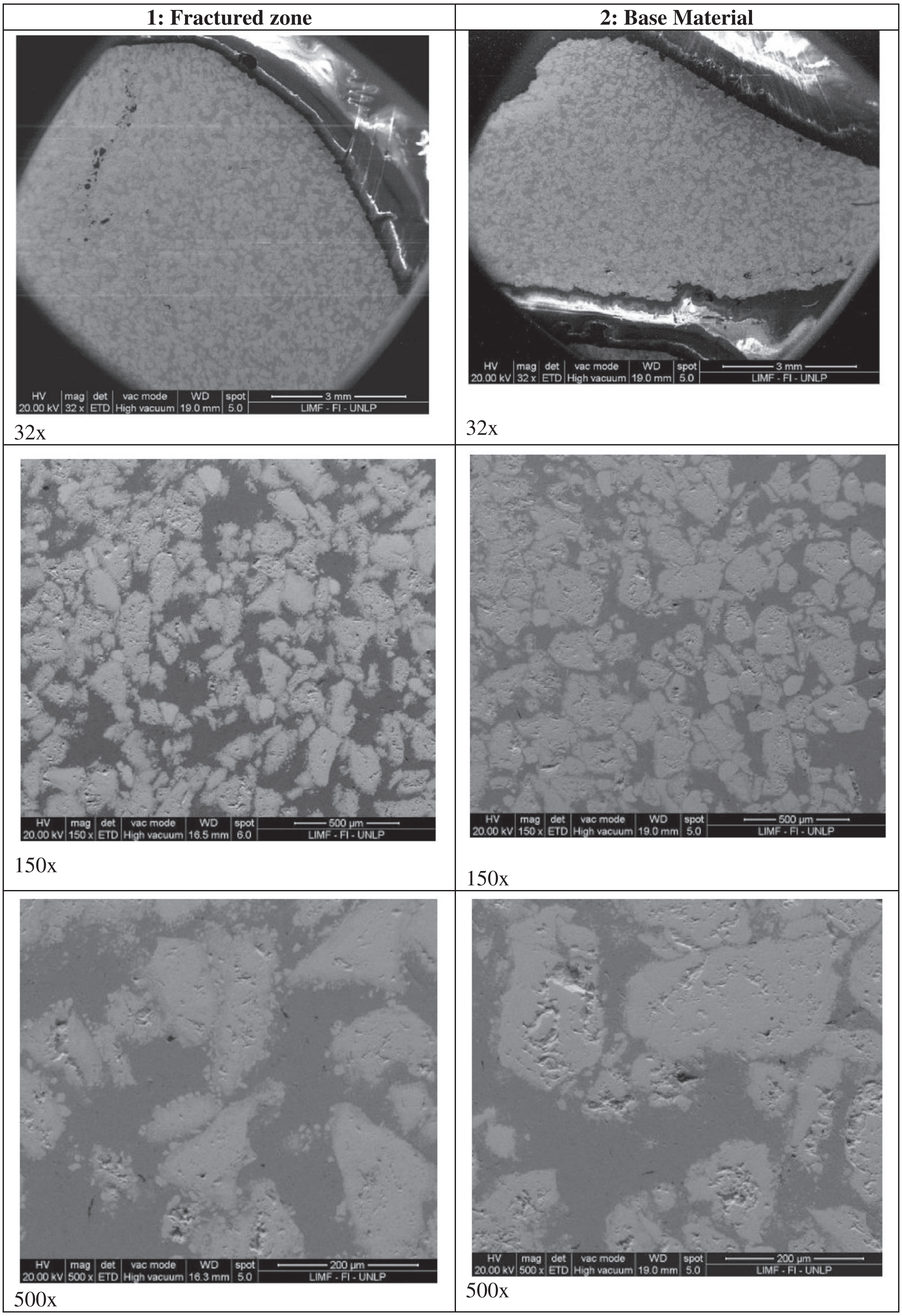


**Fig. 2.** Fractured zone and base material microstructures.

the interface between the central tube and the drill bit material applied to it.

- Close to the transition with the tubing (top of Fig. 3) the edges of the fracture surface are straight; the upper part of the fracture shows ratchet marks indicating initiation sites.

**Fig. 3.** Fracture surface of failed 8,5″ oil well drill bit: initiation sites at the top.

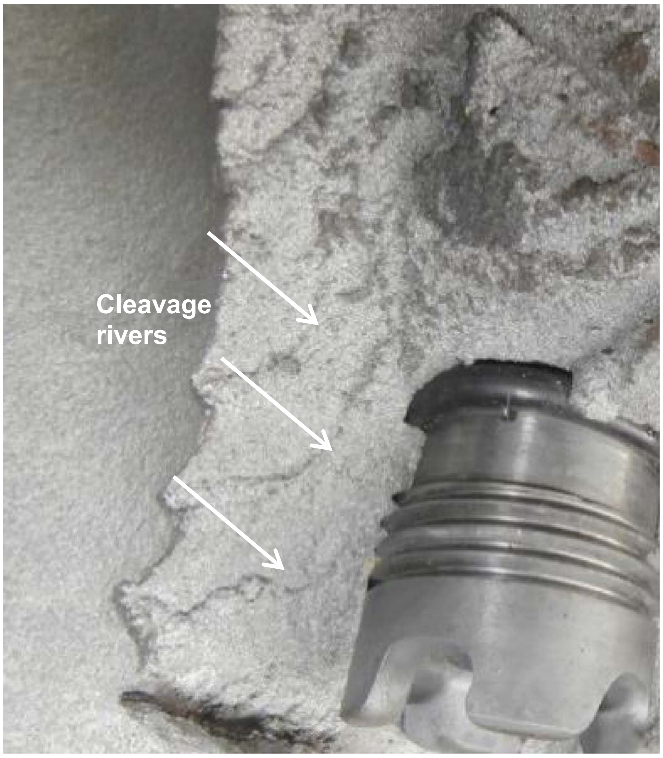


**Fig. 4.** Fracture surface, cleavage marks in the last part of fracture propagation.

- In the area of the lubrication holes (bottom of Fig. 3) there are oscillations, which indicate decay in fracture energy, and thus, represent the last part of fracture propagation.
- The fracture is brittle and symmetrical, which suggests that the failure was not torsional (due to torque), but rather due to traction forces.
- Cleavage rivers (Fig.4) indicate the final fast propagation areas.

Figs. 5–8 show results from the fractographic analysis by scanning electron microscopy (SEM). Fig. 5 (a: × 500, b: × 2000) shows the fracture surface near crack initiation, at different magnifications. Fig. 6: (× 500), taken half way intro crack propagation shows

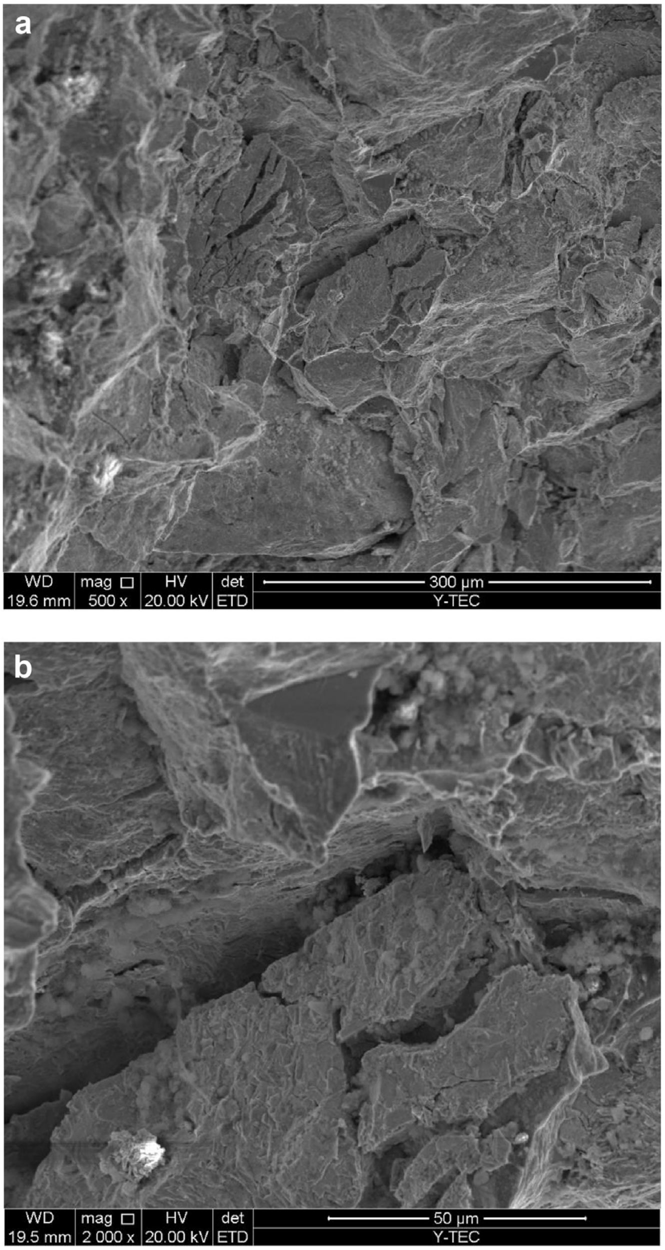


**Fig. 5.** (a × 500, b × 2000) SEM fractography near crack initiation.

some decohesion of tungsten particles. At a larger magnification, Fig. 7: (× 2000) allows identifying secondary cracks, typically formed as a result of the inability of the collapsed to accommodate lateral contraction as being broken in traction. An even closer look (Fig. 8, × 8000) gives a good image at some neatly defined cleavage planes.

The ultimate strength of drill bit material is estimated around 1200 MPa. This value is a rather conservative bound estimation from flexural strength results reported in the literature [14,15]. Albeit its brittleness, the material does not show any particular non-conformity. Tungsten carbides in the fracture surface show partial decohesion in some sectors, some degree of microporosity in other sectors, and yet other sectors show characteristic cleavage planes.

The fracture is symmetrical, which suggests that the failure was not torsional. The brittle fracture propagated from top to bottom, a likely result of some downward vertical load applied on the top of the blade, and the characteristic low toughness of the drill bit material. A brittle fracture is expected in this type of hardened material, which is designed for wear resistance but not to resist impact loads; and therefore is not attributable to any material deficiencies specific for this individual component.

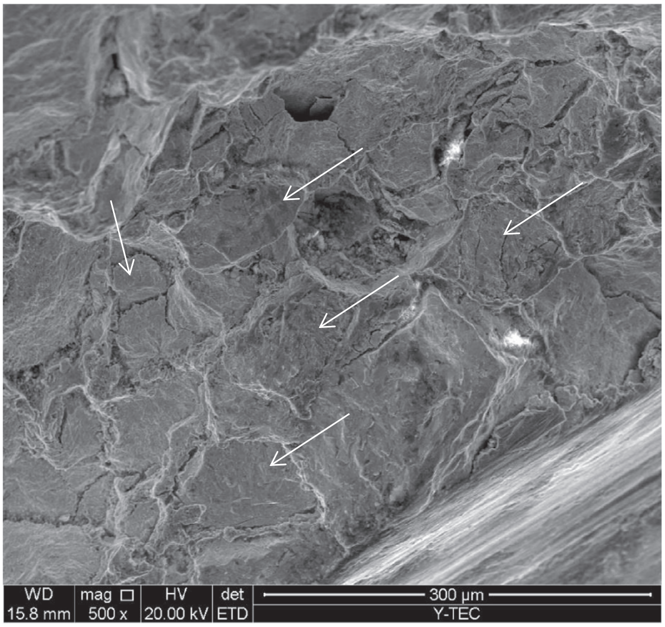


**Fig. 6.** (× 500) SEM fractography of crack propagation, decohesion of tungsten particles.

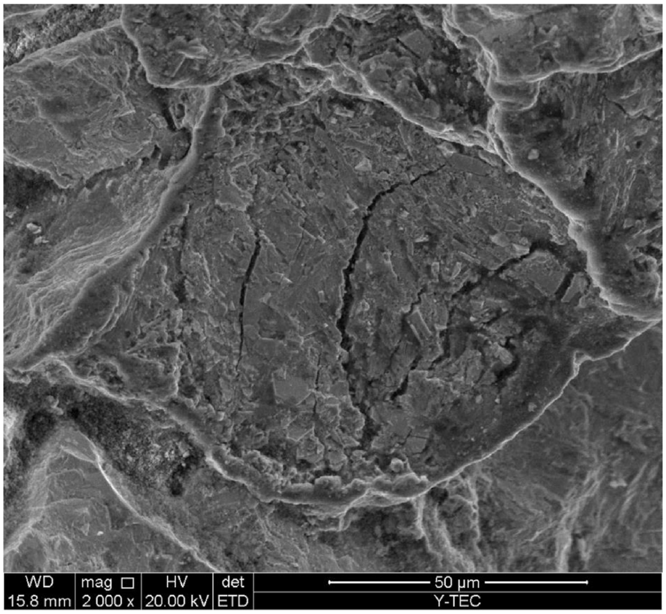


**Fig. 7.** (× 2000) SEM fractography of crack propagation, note secondary cracks.

## 3. Mechanical modeling and redesign

The fractographhic analysis concluded that the failure was not due to torsional (torque) loads, but rather due to a traction force applied on the top of the blade.

A linear elastic finite element model was performed, in which the 28 ton overpull force defined in in Table 2 was applied to the top of a single blade. This load was applied on the top surface of the blade, as shown in Fig. 9.

The stress map in Fig. 9 shows that maximum predicted stresses are located in the joining radius between the inner tube and the drill bit material, are normal to the trace of the fracture, and located at fracture initiation. Disregarding any load transferred by friction by the other blades, a 28 ton. Overpull load would lead to a maximum tensile stress of 2000 MPa, which is almost twice the breaking strength estimated for the drill bit material (1200 MPa). Therefore it is inferred that the measured overpull load was enough to cause the fracture under study.

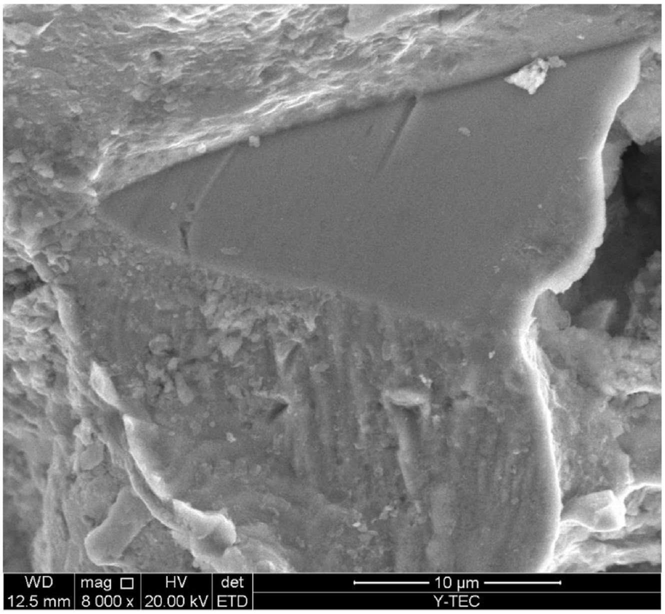


**Fig. 8.** (× 8000) SEM fractography of crack propagation, note cleavage plane.

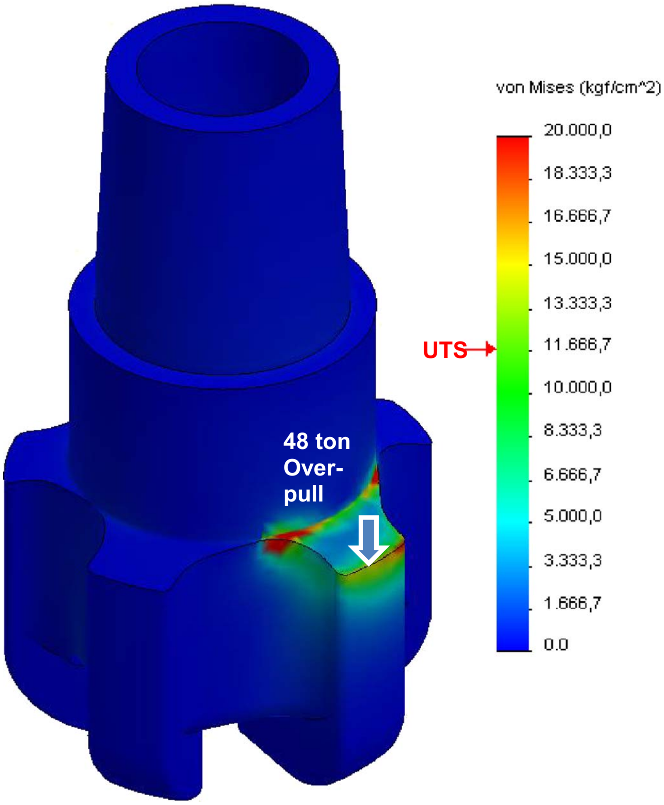


**Fig. 9.** Linear elastic FEM; stresses at failure initiation site due to overpull load.

One alternative to mitigate this problem is to avoid protrusions and other barriers within the well bore. This involves operational considerations. Regardless of the physical barrier in the well bore that produced this load during overpull, alternatives to reduce the costs of this type of failure would include reshaping the blade “elbow” to avoid the blade to stick in any obstacle protruding from the inner casing surface within the well bore. Possible redesigns of the drill bit were analyzed, such that a serious overload during an

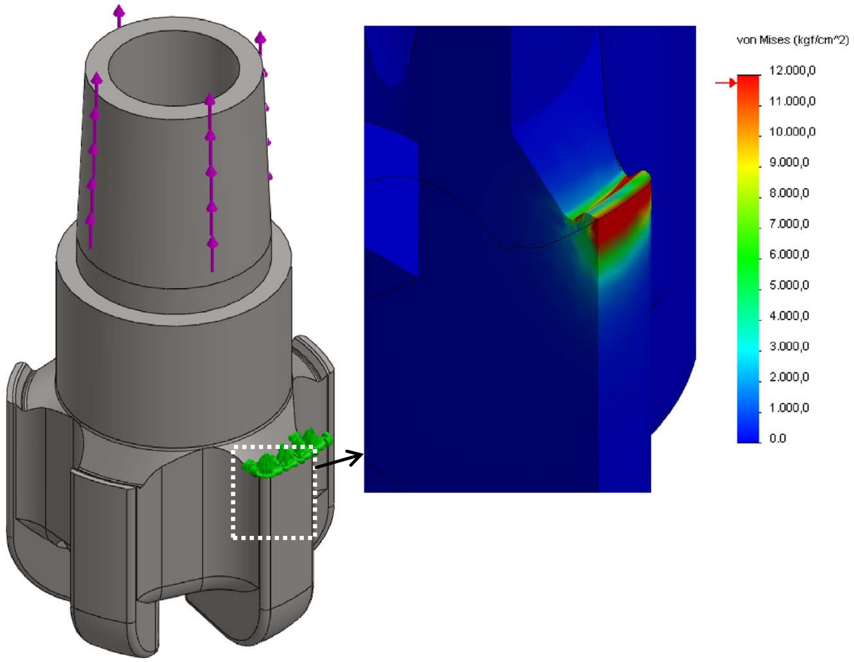


**Fig. 10.** Proposed redesign, with taper and sacrificial protuberance, maximum stresses localized at "fusible" protuberance.

overpull would not mean the complete loss of the drill bit. Tapering or making a round transition would be the first choice. But the drill bit design includes a PDC insert right in the upper - outer extreme of the blade, see Fig. 1b. While keeping this insert, it would be possible to introduce a sort of "fuse" or sacrificial piece of reduced volume, on which this insert is placed, and that would be broken free from the rest of the blade.

A stress analysis for this type of piece is shown in Fig. 10. Mechanical loads and constraints are analogous to those that would cause the studied fracture, see Fig. 9.

The proposed redesign includes a tapered upper blade shoulder, on top of which the sacrificial protuberance houses the upper PDC insert. Note that maximum stresses in the case of an overpull impact load as the one that provoked the failure has been reduced to around the strength of the material, and pretty much localized in a plane close to the "fuse" tip.

## 4. Discussion of results

Operative and material characteristics that promoted the failure were identified. Operating conditions were analyzed, bit core material in the failure and adjacent areas was analyzed and tested, and fracture surfaces identified. A stress analysis was done to confirm the conditions for failure.

Base material is a Ni-Cu-Mn matrix with tungsten carbide precipitates. Fracture surfaces showed cleavage planes and loss of particles, indicating a brittle fracture. Microstructures and hardness were similar in all analyzed regions, and according to specifications. Brittle fracture is expected in this type of hardened material, which is designed for wear resistance but not for resist impact loads; and therefore is not attributable to any material deficiencies specific for this individual component [16,17].

Failures in drill bit material have previously been related to geometrical discontinuities causing stress concentration along the tooth profiles while under effect of continuous twisting and axial impact. Even small cracks initiated in carburized, brittle matrix materials cannot be effectively restrained and propagate quickly [18].

The symmetry and characteristics of the fracture surfaces allow defining that the loads that caused the failure were not applied during the drilling operation. The blade broke apart due to a downward force applied at its base. Finite elements numerical modeling allowed pinpointing a specific moment in the pulling operation, in which a 28 ton overpull force was recorded, as the immediate operational event that caused for the failure.

One obvious recommendation would be to implement operating procedures that reduce the likelihood and amplitude of impact loads. However, these are difficult to implement in most field conditions, and could lead to serious increases in drilling times and costs [19].

More promising is the alternative for a redesign of the drill bit. There are many commercial designs for drill bits, geometries and materials vary depending on soil type and other field conditions. All these designs focus mostly on the efficiency of the cutting cycle.

The geometry of the blades can be also optimized to take into account the pull out conditions. The proposed redesign should minimize the likelihood or the costs of a failures in the case of a larger than allowable overpull load. The most efficient redesign for this specific drill bit model relies in a re-machining of the blade base, so that a large overpull load would crack a small sector, on which a PDC insert is located. In this gecko-tail type solution, only one insert would be lost, preserving the integrity of the rest of the drill-bit. Subsequent repair would involve standard thermal spray base metal techniques, including reconstitution and brazing of a new insert.

Our gecko, however, would have to make sure of the adequate disposal of its missing tail.

This is a very hard piece and regular drill bits cannot drill through it. Should a “fish” or “junk” fall into a well, “fishing” is required to remove it. Dropping stuff into a well, is a problem as old as mankind and wells [20]. The oil and gas industry has developed a variety of “fishing tools”. Each tool is specially crafted to perform a specific function, or retrieve a certain type of fish. Most fishing tools are screwed into the end of a fishing string, similar to drill pipe, and lowered into the well. There are several options to recover large pieces, most commonly, broken pipe sections [21].

Fishing a well may take days to complete, and during this time, drilling cannot occur. The cost of fishing would then be larger than the cost of the lost drill bit, so retrieving the lost piece should be fast and easy; the fishing procedure must be an integral part of the “improved drill bit” package. When a fish is small, as would be this case, drilling fluid and a boot basket are used to retrieve the small debris from the wellbore. Drilling fluid is pumped into the well, the small parts of the fish are raised into the basket and then to the surface by the boot basket. To help determine the best procedure to retrieve the fish, an impression block is often previously used to get an impression of size and position of the missing part(s).

## 5. Conclusions

The failure analysis described in this article concluded that the loss of one of the three blades of the oil well drill bit did not occur during the drilling operation. The blade broke apart during the pulling operation.

One obvious recommendation is to implement operating procedures that reduce the likelihood and amplitude of impact loads during pull back. But these are difficult to implement in most field conditions and could lead to serious increases in drilling times and costs. More promising is the alternative for a redesign of the drill bit.

There are many commercial designs for drill bits, geometries and materials vary depending on soil type and other field conditions. All these designs focus mostly on the efficiency of the cutting cycle. The geometry of the blades could also be optimized to take into account the pull out conditions. A redesign that could minimize the cost of a drill bit failure in the case of a larger than allowable overpull load is proposed and discussed.

The most efficient redesign for this specific drill bit model was found to rely in a re-machining of the blade base, so that a large overpull load would crack free a small sector, on which a PDC insert is located. In this gecko-tail type solution, only one insert would be lost, preserving the integrity of the rest of the drill-bit. Subsequent repair would involve standard thermal spray base metal techniques, including reconstitution and brazing of a new insert.

The lost piece would go down to the well bottom, and must also be taken care of. This is a very hard piece and regular drill bits cannot drill through it without suffering some further damage. The cost of recovering the missing part from the wellbore would be larger than the cost of the lost drill bit, so retrieving the lost piece should be fast and easy: the “fishing” procedure must be an integral part of the “improved drill bit” package. The oil and gas industry has developed a variety of fishing tools and methods. For recovering small pieces, fluid is pumped into the well, the parts are raised into a basket and then to the surface.

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