How to drill a usable wellbore

Why deviation occurs

Summary

Crooked wellbore troubles such as doglegs and key seats can increase drilling costs, destroy drilling equipment and cause problems in production operations. Thus operators and drilling contractors concentrate efforts towards drilling smooth, usable wellbores with minimum amounts of deviation.

This document presents a series of pages on controlling deviation, discusses reasons wellbores become crooked and the problems that can result.

When rotary drill commenced drill collars as we know them today did not even exist. Bit technology also did not have the capability in design or construction to apply heavy loads and only the weight of the drill pipe with a crossover sub (called a collar) between the drill pipe and bit, supplied the drilling weight.

Increased drilling depths and harder formations brought about development of new and improved rotary bit technology and identified the need to design bottom-wellbore assemblies to provided additional weight to make the bit drill.

Initially more weight on the bit was realised through slacking off additional drill pipe weight resulting in more drill pipe in compression. This resulted in an increased number of drill pipe failures. When drill pipe is run in compression for bit weight, it buckles and is subject to severe bending fatigue. Stress reversals in the thin wall of the drill pipe are created by rotating the pipe in compression while bent. Based on this theory, the idea emerged of using heavy thick-walled pipe between the bit and drill pipe to furnish the necessary bit weight. These heavy thick-walled joints were called drill collars after the crossover sub used earlier.

Only a few collars were used initially, but the quantity increased rapidly with improved bit design and deeper drilling. Very few problems were encountered when only six to nine drill collars were used. However, connection failures increased rapidly with the running of additional collars because collars buckled under the extra weight. Drill collars differ from drill pipe in that the highest points of stress are in the connection—the drill collar tube or body is much stiffer and stronger than the connection. The use of special bottom wellbore assemblies (BHA’s) to centralize the collars and stiffen the connections were not yet in use.

Initially, not much thought was given to deviation. It was believed that if the kelly were held straight in starting the wellbore, it would continue straight. No one realized wellbores were being drilled crooked until development of Seminole field, Oklahoma, in about 1928 and 1929. Suspicions arose when some wells required considerably more casing to complete than others. This was confusing since wells were assumed to be in the same producing horizon.
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Finally when two offset drilling wells actually intersected, causing numerous fishing jobs, it was realized that crooked wellbores were possible. The cost of additional tubing and casing to complete these crooked wellbores became a concern, and deviation became important.

After development of deviation-recording instruments, operators began writing specifications requiring that wellbore angle be maintained within some specified maximum. At first, deviation controls were liberal, with 100 to 15° being acceptable as maximum inclination from vertical. However, during this period, California courts ruled that wells crossing over lease boundary lines onto other properties were trespassing, and lawsuits resulted. Also about this same time, Dr. Fredrick Lahee advocated that, for geological information to be valid, deviation should not exceed 10 to 20.1,2 Operators over-reacted to both situations, and by the early 1930’s, 1° to 3° was the maximum permissible wellbore deviation from top to bottom.

Later, during the 1940’s, deviation restrictions in some areas were relaxed, because deeper and harder formations being drilled required more weight to make the bit drill, and therefore it was almost impossible to stay within a 1° to 30 contract. However, operators ignored the rate of wellbore angle change, and did not eliminate crooked wellbore problems caused by severe doglegs. During the 1950’s, both operators and drilling contractors became concerned about the additional amount of money required to stay within a 30 to 5° contract. In most wells a reduction of bit weight was necessary to stay within maximum permissible deviation, resulting in slower penetration rates and higher drilling costs.

What causes crooked wellbores?
While the exact root cause of crooked wellbores is perhaps difficult to recognize, some logical theories have been conceived.

Drill collar size
Henry Woods and Arthur Lubinski stated in 1954, that size of bottom-wellbore drill collars is the limiting factor for lateral movement, and minimum effective wellbore diameter (MEHD) could be calculated by the following equation:

MEHD — Bit Size + Drill Collar OD x 2

Hard ledges
This was followed by Robert S. Hoch’s theory that, while drilling with an non-stabilized bit, an abrupt change in wellbore angle can occur if hard ledges are encountered, Fig. I. He pointed out that a dogleg of this nature would cause an undersized wellbore, making it difficult or impossible to run casing. Hoch stated, “To
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minimize the possibility of sticking casing strings in wellbores drilled with non-stabilized or single stabilized drill collars, it is suggested that the minimum permissible bottom-wellbore drill collars outside diameter always be larger than twice the casing coupling outside diameter to be run, minus the bit size.”

*Fig. 1:* while drilling with an non-stabilized bit, an abrupt change in wellbore angle can occur if hard ledges are encountered. To correct this problem, it is recommended that the minimum drill collar OD be larger than twice the casing coupling OD minus the bit size.

Non-stabilized bits.

About this same time, H. E. Treichler theorized that the lateral movement of an non-stabilized bit in non-dipping formations tends to cut a spiralled wellbore, *Fig. 2.* Also, spiralling will be more severe in soft formations where penetration rate is greater, and this will produce an undersized wellbore.

*Fig. 2:* A spiral wellbore, caused by an non-stabilized bit drilling in non-dipping formations, will have a lower effective diameter than actual bit OD.

The whip-stock theory

The whip-stock theory, introduced by H. M. Rollins, was that formations drilled while searching for gas and oil are sedimentary formations, laminar in structure. If these formations are dipping, as the bit drills through each lamination it may reach a load at which that lamination can no longer support the load and it will fracture down to the next lamination. Most formations tend to fracture perpendicular to the bedding planes leaving, on the uphill side of the wellbore, a small wedge of material that is broken up and easily drilled. Or, the wedge may break away and not require drilling. Conversely, on the downhill side of the wellbore, a small wedge of material is left attached to the lamination. This wedge forms a small whip-stock that tends to force the rock bit laterally up dip or uphill.

*Fig. 3:* When formations dipping less than 450 are drilled, often the bit will tend to drill up dip causing a deviated wellbore. In theory, small whip-stocks formed at formation laminations cause the bit to drill off course.

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A variation of the whip-stock theory is that ledges, off sets and doglegs are formed when the bit drills hard and soft laminar formations one after the other and the soft sections wash out. Drill collars, being smaller in diameter than the bit, allow the bit to move laterally within the washed-out soft formations before drilling the hard sections. After drilling several hard sections, the wellbore through the hard sections may not be in line,

Fig. 4: Alternating hard and soft formations can result in offset ledges. Washouts in the softer formations allow the drillstring to change directions.

Drillstring bending characteristics

Another factor is the drillstring’s bending characteristics. In an already deviated wellbore, with no weight on the bit, the only force acting on the bit is the weight of the string between the bit and the tangency point. This force tends to bring the wellbore toward vertical. When weight is applied, the resulting force tends to direct the wellbore away from vertical. When combined, these two forces may increase angle, decrease angle or maintain constant angle. This theory was offered by Arthur Lubinski and was based on the assumption that the drillstring lies on the low side of an inclined wellbore, Fig. 5.

Fig. 5: Since the drillstring lies on the low side of an inclined wellbore, a slightly deviated well will become more highly deviated since the weight of the drillstring forces the bit toward the high side of the wellbore.

Formation drill-ability

Generally, soft formations make drilling a straight or nearly vertical wellbore much easier than do very hard formations. In particular, the effects of the drill stem bending and dip may be much less when drilling soft formations, while hard formations at high dip angles require high bit weights. All of these factors then work against drilling a straight or vertical wellbore.

Many problems can be prevented by obtaining the broadest possible limits for deviation. By relaxing deviation clauses in drilling contracts to reasonable limits, it is possible to drill a straight wellbore at high penetration rates and avoid the costly operations of plugging back and straightening the wellbore.

Also, it may be possible to select a location that will allow the well to drift into the target area. For example, if it is desired to reach a certain point on the structure and it is known that the well will drift in a certain direction up
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structure, it is desirable to have the surface location down dip so that when drilling normally, the bottom of the well will drift into the target area.

**Why restrict wellbore angle?**

Total wellbore angle should be restricted to keep the well on a particular lease, to insure a specific pay zone e.g. such as a stratigraphic trap, a lensing sand, a fault block, etc. is penetrated, or to drill a near vertical wellbore required by regulatory agencies. The restriction of total wellbore angle may solve some problems, but it is not a cure-all. As shown in Fig. 6, the typical 5° limit does not assure the well is free of troublesome doglegs.

Mr. Lubinski pointed out that the rate of wellbore angle change should be the main concern, not necessarily the maximum wellbore angle. In 1961, an API study group published a tabular method of determining maximum permissible doglegs that would be acceptable. The main objective is to drill a useful wellbore with a full gage, smooth bore and free of doglegs, key seats, offsets, spirals and ledges.

![Fig. 6: previously, limits to deviation included in drilling contracts did not eliminate the more serious problem of doglegs. The rate of angle change or dogleg severity is one of the most important factors in deviation control.](image)

**Doglegs and key-seats**

A key seat is formed after part of the drill pipe string has passed through a dogleg. Since the pipe is in tension, it tries to straighten while going around the dogleg thus creating a lateral force that causes the drill pipe to cut into the centre of the bow as it is rotated.

![Fig. 7: when rotated through a dogleg, drill pipe is subjected to extreme cyclic loading, left. Continued drilling through a dogleg can result in a key seat, right, a situation that causes even more problems later.](image)

The force is proportional to the amount of weight hanging below the dogleg. A key seat will be formed only if the formation is soft enough and the lateral force great enough to allow penetration by the drill pipe. When severe dog-legs and key seats are formed, many problems can develop.

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Drill pipe fatigue.
If a program is designed so that drill pipe damage is avoided while drilling, then the wellbore will be acceptable for conventional designs of casing, tubing and sucker rod strings. An example of the severe dogleg condition that produces fatigue failures in drill pipe can be seen in Fig. 7. The stress at Point B is greater than the stress at Point A, but as pipe is rotated, Point A moves from the inside of the bend to the outside and back to the inside again so that every fibre on the pipe goes from minimum tension to maximum tension and back again and again. Cyclic stress reversals of this nature cause fatigue failures in drill pipe, usually within the first two feet of the body adjacent to the tool joint where there is an abrupt change of section.

To avoid rapid fatigue failure of pipe, the rate of change of the wellbore angle must be controlled. Suggested limits can be seen in Fig. 8.

This graph is a plot of pipe tension versus change in wellbore angle in degrees per 100 feet. This curve, designed for 4 1/2 -inch, 16.6 ppf, Grade E drill pipe in a gradual dogleg: Damage to the drill pipe is avoided when conditions fall to the left of the fatigue curve. If a dogleg is high in the wellbore with high tension in the pipe, only a small change in angle can be tolerated. Conversely, if the dogleg is close to the total depth, tension in the pipe will be low and a larger change in angle can be tolerated. If the stress endurance limit of the drill pipe is exceeded because of rotation through a dogleg, an expensive fishing job or junked wellbore could develop.

Stuck pipe
Sticking can occur by sloughing or heaving of the wellbore and by pulling large OD drill collars into a key seat while pulling the drill stem out of the wellbore.

Logging and wire-line tools
Logging tools and wire-lines can become stuck in key seats. The wall of the wellbore can also be damaged, causing wellbore problems.
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Running casing
Running casing through a dogleg can be a very serious problem. If casing becomes stuck in the dogleg before reaching the productive zone, it would be necessary to drill out the shoe and set smaller size pipe through the productive interval. Even if casing is run to bottom successfully, it could be severely damaged, thereby preventing running of production equipment.

Cementing
A dogleg will force casing tightly against the wall of the wellbore, preventing a good cement job since cement cannot circulate between the wall of the wellbore and the casing at the point of contact.

Casing wear
Drill pipe rotating against casing in the dogleg or dragging through it while tripping, can wear a wellbore in the casing.

Production problems
Rod wear and tubing leaks associated with doglegs can cause expensive repair jobs. It may be difficult to run packers and tools in and out of the well without getting stuck because of distorted or collapsed casing.
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Designing the bottom-wellbore assembly

Summary
Conditions in certain areas cause wellbores to deviate, but techniques are available to reduce or eliminate the deviation. A popular method is to use the packed-wellbore assembly. Equipment and methods for its selection are presented in the following article. Other deviation control measures are also discussed.

In first part of this document, causes of bit deviation and the problems associated with crooked wellbores were discussed. In this section, two possible solutions; pendulum and packed-wellbore assemblies are described.

Also included are:
- A description of tools making up a bottom wellbore assembly
- Methods of designing assemblies for mild, medium or severe crooked wellbore conditions
- A discussion of the combined packed pendulum theory.

Pendulum Theory
In the early 1950's, Woods and Lubinski collaborated in a mathematical examination of the forces on a rock bit when drilling in an inclined wellbore. To make the calculations, they made three basic assumptions, namely:

1. The bit is like a ball-and-socket joint, free to turn, but laterally restrained.
2. Drill collars lie on the low side of the wellbore and will remain stable on the low side of the wellbore.
3. The bit will drill in the direction in which it is pushed, not necessarily in the direction in which it is aimed.

Consequently, the forces which act upon the bit can be resolved into three components: Axial load, pendulum force and formation reaction.

Axial load
The axial load is supplied by the weight of the drill collars.

Pendulum force
The lateral or pendulum force results from weight of the drill collar between the bit and the first point of contact with the wall of the wellbore by the drill collar. Pendulum force is the tendency of the unsupported length of drill collar to swing over against the low side of the wellbore because of gravity.
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Formations reaction

It is the only force that tends to bring the wellbore back towards vertical, Fig. 9.

Fig. 9—The pendulum force or restoring force of drill collar weight results from the tendency of the unsupported length of drill collar to swing over against the low side of the wellbore.

The third is the reaction of the formation to these loads, which may be further resolved into two forces, one parallel to the axis of the wellbore and one perpendicular to the axis of the wellbore. This work indicated that gravity could be used as a means of controlling change in wellbore angle. Special tables were prepared to show the weight necessary for the bit to maintain a certain wellbore angle. Tables show the proper placement of a stabilizer to give maximum pendulum force and maximum bit weight. Effects of using larger drill collars can also be determined. Copies of the complete set of tables can be obtained from service company handbook or tables.

Packed-wellbore theory

Most companies use a packed bottom-wellbore assembly to overcome crooked wellbore problems, and the pendulum is used only as a corrective measure to reduce angle when maximum permissible deviation has been reached. The packed-wellbore assembly is sometimes referred to as the gun barrel approach because a series of stabilizers is used in the wellbore already drilled to guide the bit straight ahead. The bottom-wellbore assembly should be designed with the necessary stiffness and wall contact tools to force the bit to drill in the general direction of the wellbore already drilled. If the proper selection of drill collars and bottom-wellbore tools is made, only gradual changes in wellbore angle will develop, resulting in a useful, full-gage, smooth wellbore, free of dog-legs, key seats, offsets, spirals and ledges.

Packed wellbore design factors

Tool assembly length

It is important that wall contact assemblies provide sufficient length of contact to assure alignment with the wellbore already drilled. Experience confirms that a single stabilizer just above the bit generally acts as a fulcrum or pivot point. This will build angle because the lateral force of the non-stabilized collars above, will cause the bit to push to one side as weight is applied. Another stabilizing point, for example, at 30 feet above the bit will nullify some of the fulcrum effect. With these two points, the assembly will stabilize the bit and remove some of the angle-building tendency, but it would not be considered a
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good packed-wellbore assembly. A good assembly requires three stabilization points. As shown in Fig. 10, two points can contact and follow a curved line, but adding one more point eliminates this tendency.

Fig. 10: the packed bottom wellbore assembly results from the basic idea that three points cannot contact and follow a curved wellbore

Stiffness

Stiffness is probably the most misunderstood of all drill collar design considerations. Few realize the importance of diameter and its relationship to stiffness—if the diameter of a bar is doubled, its stiffness is increased 16 times. For example, if an 8-inch diameter bar is deflected 1-inch under a certain load, a 4-inch diameter bar will deflect 16 inches under the same load. Table 1 lists the moments of inertia (I), which are proportional to stiffness for popular drill collar sizes.

Large diameter drill collars provide the most stiffness, so it is important to select the maximum diameter collars that can be run safely. Drill collars increase in stiffness by the fourth power of the diameter. For example, a 9½-inch collar is four times stiffer than a 7-inch drill collar and is two times stiffer than an 8-inch drill collar.

Clearance

There needs to be a minimum clearance between wall of the wellbore and stabilizers. The closer the stabilizer is to the bit, the more exacting are clearance requirements. For example, if a clearance of 1/16" under-gage from wellbore diameter is satisfactory just above the bit, then 60 feet above the bit, 1/8" clearance may be sufficient. In some areas, wear on contact tools and clearance can be a critical factor for a packed wellbore assembly.

Wall support

Bottom-wellbore assemblies must adequately contact the wall of the wellbore to stabilize the bit and centralize drill collars. Length of contact needed between the tool and wall is determined by the formation. The surface area in contact must be sufficient to prevent the stabilizing tool from digging into the wall. If this should happen, stabilization would be lost and the wellbore would drift. If the formation is hard and uniform, a short narrow contact surface is adequate and will insure proper stabilization. However, if the formation is soft and unconsolidated, a long blade stabilizer may be required. Wellbore enlargement in formations that erode quickly tends to reduce effective alignment of the bottom-wellbore assembly. This problem can be reduced by controlling annular velocity and mud properties.
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**Bottom wellbore assembly design**

Proper design of a packed-wellbore assembly requires that crooked wellbore tendencies and degree of formations drill-ability be considered. In this article, crooked wellbore tendency will be considered as either mild, medium or severe. Formation firmness is rated as either soft to medium hard or medium hard to hard, which is further divided into abrasive or non-abrasive.

**Mild crooked wellbore**

The packed-wellbore assembly for mild crooked wellbores, Fig. 11; left is considered minimal for straight wellbore drilling and bit stabilization.

Fig. 11—Additional string stabilizers are added to the packed wellbore assembly as deviation conditions increase from mild to medium and to severe. The short drill collar size, located between zone 1 and zone 2, is determined by wellbore size. The wellbore size in inches should approximate the short drill collar length in feet, plus or minus two feet.

Three points of stabilization are provided by zone 1 immediately above the bit, zone 2 above the large diameter short drill collar and zone 3 above a regular length, large diameter collar. A vibration dampener (when used) should be placed above zone 2 for best performance. If crooked wellbore conditions are minimal, the vibration dampener may be run in place of the short drill collar between zone 1 and zone 2. When rough drilling conditions are encountered, a vibration dampener will increase penetration rate and add life to the bit.

Wear and damage to the drilling rig and drill stem will also be reduced.

**Medium crooked wellbore**

A packed-wellbore assembly for medium conditions is similar to the preceding except for the addition of a second stabilizing tool in zone 1, Fig. 11-center.

The two tools run in tandem provide increased bit stabilization and add stiffness to limit angle changes caused by lateral forces.

**Severe crooked wellbore**

In severe crooked wellbore areas three stabilization tools are run in tandem in zone 1 to provide maximum stiffness and wall contact to aim and guide the bit. In 8 3/4-inch and smaller wellbore sizes, recommendations call for a large diameter short collar between zone 2 and zone 3. This increases stiffness by reducing deflection of the total assembly and allows tools in zone 1 and zone 2 to function without excessive wear caused by lateral thrust or side-loading from excess deflection above, Fig. 11-right.

As a general rule of thumb for all three conditions, short drill collar length in feet should be about equal to wellbore size in inches, plus or minus two feet.
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For example, a short collar length of 6 to 10 feet would be satisfactory in an 8” wellbore.

Stabilising tools

The three basic types of stabilizing tools include the rotating blade, non-rotating rubber sleeve and the rolling cutter reamer. Some variations of these tools are as follows:

A rotating blade stabilizer can be a straight blade or spiral blade configuration, and in both cases the blades can be short or long, Fig. 12.

Rotating blade stabilizers are available as either shop repairable or rig repairable. Shop repairable tools are either integral blade, welded blade or shrink-on sleeve construction. Welded blade stabilizers are popular in soft formations, but are not recommended in hard formations because of rapid fatigue damage in the weld area.

Rig repairable stabilizers

Rig repairable stabilizers either have a replaceable metal sleeve or replaceable metal wear pads such as the RWP Stabilizer. These tools were originally developed for remote locations, but have received wider acceptance in normal use during the last few years.

All rotating blade stabilizers have fairly good reaming ability and because of recent improvements in hard-facing, they have a very good wear life. Hard facing materials used include granular tungsten carbide, crushed sintered tungsten carbide, sintered tungsten carbide (in laid) and pressed in sintered tungsten carbide compacts.

The rig replaceable non-rotating rubber sleeve

The rig replaceable non-rotating rubber sleeve stabilizer is safe to run from the standpoint of sticking and wash over, Fig. 12; centre. It is most effective in hard formations such as lime and dolomite. Since the sleeve is stationary, it acts like a drill bushing and will not dig into and damage the wall of the wellbore. However, the sleeve is made of rubber and should not be used in temperatures over 250° F. It has no reaming ability and sleeve life may be short in wellbores with rough walls.
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Roller cutter reamers
Rolling cutter reamers, Fig. 12; right, are used for reaming and added stabilization in hard formations. Wall contact area is very small, but it is the only tool that can ream hard rock effectively. Any time rock bit gage problems are encountered, the lowest contact tool should definitely be a rolling cutter reamer.

**Stabilizer selection**

**Mild, medium, severe crooked wellbores, hard to medium formations**
Mild, medium, severe crooked wellbores, hard to medium formations, selection are illustrated in Fig. 13.

Fig. 13: in mild, medium and severe crooked wellbore areas with hard to medium formations, these stabilizing tools are suggested. A rolling cutter reamer should be used in abrasive formations. In zone 2, a non-rotating rubber sleeve stabilizer may be used.

In zone 1-A (directly above the bit) a rolling cutter reamer should be used when bit gage is a problem in hard and abrasive formations. A six point tool would be required for extreme conditions. In non-abrasive formations, a rotating blade tool with hard-facing is desirable.

Rotating blade type tools would be good in zone 2 for all three conditions of crooked wellbore tendencies. In very mild crooked wellbores, a non-rotating sleeve type tool would suffice.

With the slightest deviation from vertical, drill collars will lie on the low side of the wellbore because of their enormous weight. Thus, the function of zone 3 is to pull the collars away from the wall and prevent any lateral force from being transmitted to the bit. Both rotating blade and non-rotating rubber sleeve stabilizers may be used for this job in hard to medium hard formations. Any stabilizers run above zone 3 would be used only to prevent the drill collars from buckling or becoming "wall stuck." In most cases these stabilizers would have little effect on directing the bit.

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Medium & severe crooked wellbores hard to medium hard formations

Medium and severe crooked wellbores hard to medium hard formations are presented in Fig. 14. A rotating blade stabilizer is recommended in zone 1-B under these conditions. For severe crooked wellbore drilling, the same type of tool could be used in zone 1-C.

Fig. 14—Shown are suggested tools for use in medium and severe crooked wellbore areas when formations are hard to medium hard. The same tool shown here for zone 1-B would be used in zone 1-C for severe wellbores.

Mild, medium & severe crooked wellbores, medium hard to soft formations

Mild, medium and severe crooked wellbore, medium hard to soft formations tools in these formations, where bit gage is no problem, must provide maximum wall contact length for proper drill collar and bit stabilization. For all degrees of crooked wellbore tendencies, rotating blade stabilizers are recommended, Fig. 15.

Fig. 15; when formations are soft to medium hard and wellbore conditions run from mild to medium and severe deviation, these stabilizers are recommended.

Modern packed-wellbore assemblies, when properly designed and used, will reduce rate of wellbore angle change. Also, they will improve bit performance and life by forcing the bit to rotate on a true axis about its design centre, thus loading all cones equally. Packed-wellbore assemblies allow use of more drilling weight through formations which cause abnormal drift. The desired wellbore angle and course are maintained in directional drilling. In this controlled situation, high angles can be drilled with minimum danger of key seating or excessive pipe wear.

Packed pendulum

Because all packed-wellbore assemblies will bend, however small the amount of deflection, it is impossible to drill a perfectly vertical wellbore. The rate of wellbore angle change will be kept to a minimum but occasionally conditions will arise in which total wellbore deviation must be reduced. When this condition occurs, the pendulum technique is employed. If it is anticipated that the packed wellbore assembly will be required after reduction of the wellbore angle, the packed pendulum technique is recommended, Fig. 16.
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Fig. 16: The packed pendulum assembly is used to decrease wellbore angle especially when a packed-wellbore assembly will be required after wellbore angle is reduced.

In this technique, the pendulum length collars are swung below the regular packed-wellbore assembly. When wellbore deviation has been dropped to an acceptable limit, the pendulum collars are removed and the packed-wellbore assembly again is run above the bit. It is only necessary to ream the length of the pendulum collars prior to resuming normal drilling.

If a vibration dampening device is used in the packed pendulum assembly, it should remain in its original pickup position during the pendulum operations.

Reduced bit weights

By reducing the bit weight, bending characteristics of the drill string are changed and the wellbore will tend to be straighter. One of the oldest techniques for wellbore straightening was to reduce bit weight and increase rotary speed. In recent years, it has been found that this is not always the best procedure because reducing the bit weight sacrifices considerable penetration rate. Worse, it frequently causes doglegs, Fig. 17.

Fig. 17—Reduced bit weight can be used to reduce wellbore angle, but it can frequently result in doglegs. Wellbore angle reduction by reducing bit weight should be carried out very gradually.

A point of caution: wellbore straightening accomplished by reducing bit weight should be done very gradually so that the wellbore will tend to return to vertical without sharp bends. A reduction in bit weight is usually required when changing from a packed-wellbore assembly to a pendulum or packed pendulum drilling operation.
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Selecting the drill collar string

Summary
The proper choice of a drill collar string is important to obtaining the best quality wellbore at minimum cost. Collars, available in many combinations of sizes and thread types, should be selected based on the wellbore size to be drilled and expected drilling conditions. Other considerations include special features such as spiral grooving and elevator recesses.

The selection of a properly engineered drill collar string is a primary requirement for achieving minimum cost drilling. A well matched drill collar string aids in achieving a trouble free, usable wellbore, provides bit weight in the amount needed, assists in obtaining and maintaining desired wellbore direction and insures prolonged drill pipe life and performance. Factors that should be considered in designing the drill collar string include:

- Collar size
- Type of connection
- Special collar features
- Transition zone equipment.

Drill collar size
The wellbore size and bit program will determine the best drill collar size, but collars selected usually have the largest OD and maximum permissible wall thickness that can be safely run in the wellbore.

Several benefits will be derived from this general rule, namely:

- Fewer drill collars are needed for required weight
- Fewer drill collar connections are required
- Less time is lost handling drill collars during trips
- Factors governing good bit performance favour close fitting stiff members
- Fatigue damage of connections is less with drill collars that fit the wellbore closely.

The buoyed weight of the collar string should be at least 15% greater than maximum anticipated bit weight. The neutral point between tension and compression should always be kept within the drill collar string.

There are some exceptions to the recommendation of selecting drill collars that fit the wellbore closely. As discussed later, two or more different sizes of drill collars are often used in large diameter wellbores. In highly deviated directional wellbores, excessive torque and drag are encountered with conventional drill collar strings. In such cases, two or three drill collars with stabilizers placed as required may be used directly above the bit. Remaining weight then is supplied by 30 to 33 joints of heavy wall drill pipe, which has the same OD as standard drill pipe and can be handled in the same manner on trips. Wall thicknesses from /8 to 1 inch allow pipe to be run in compression.
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The drill collar bore, primarily a hydraulic consideration, is determined by the minimum size that will handle required circulation without excessive pressure drop. Drill collars of 2’4” inch ID and larger will handle most tools that must pass through the bore. Remember, manufacturers only guarantee a drill collar bore will drift one eighth of an inch smaller than the nominal internal diameter of the collar.

Small diameter free point indicators, string shots and survey instruments have been designed to go into very small drill collar bores. However, small instruments often are not as reliable as the larger ones. If horizontal angle measurements are required, a larger bore is needed than for strictly vertical angle measurements. Hot wellbores may require insulated barrels on instruments and thus, require a larger bore for passage. Some special work may require extra large bores for gyro instruments or wire-line core barrels.

Programs for various wellbore sizes

Combinations of drill collar sizes and connections now being used in common wellbore sizes are listed in Table 2. This is not a complete list of all sizes, but a large percentage of wellbores now being drilled will fall into these classifications.

Table 2: popular wellbore and drill collar sizes

<table>
<thead>
<tr>
<th>Hole size, inches</th>
<th>Drill collar sizes and connections</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Soft formation</td>
</tr>
<tr>
<td>4½-4¾</td>
<td>3½” OD x 1¼” ID with 2½” PAC or 2½” Reg.</td>
</tr>
<tr>
<td>5½-6¼</td>
<td>4½” OD x 2½” ID with 2½” IF</td>
</tr>
<tr>
<td>6½-6¾</td>
<td>6¾” OD x 2¼” ID with 2½” IF</td>
</tr>
<tr>
<td>7½-7¾</td>
<td>7½” OD x 2¼” ID with 2¼” IF or 4” H-90</td>
</tr>
<tr>
<td>8½-8¾</td>
<td>8½” OD x 2¼” ID with 2¼” IF or 4” H-90</td>
</tr>
<tr>
<td></td>
<td>Hard formation</td>
</tr>
<tr>
<td>4½-4¾</td>
<td>3½” OD x 1½” ID with 2½” PAC or 2½” Reg.</td>
</tr>
<tr>
<td>5½-6¼</td>
<td>4½” OD x 2” ID with 3½” XH or 2½” IF</td>
</tr>
<tr>
<td>6½-6¾</td>
<td>6½” OD x 2½” ID with 3½” IF</td>
</tr>
<tr>
<td>7½-7¾</td>
<td>7½” OD x 2½” ID with 4” H-90 or 4” H-90</td>
</tr>
<tr>
<td>8½-8¾</td>
<td>8½” OD x 2½” ID with 4½” IF or 4” H-90</td>
</tr>
<tr>
<td>9½-9¾</td>
<td>9½” OD x 2½” ID with 5½” IF</td>
</tr>
<tr>
<td>10½-11</td>
<td>10½” OD x 2½” ID with 6½” H-90 or 6½” Reg.</td>
</tr>
<tr>
<td>12½</td>
<td>12½” OD x 2½” ID with 8½” H-90 or 8½” Reg.</td>
</tr>
<tr>
<td>14½</td>
<td>14½” OD x 2½” ID with 9½” H-90 or 9½” Reg.</td>
</tr>
<tr>
<td>16½</td>
<td>16½” OD x 2½” ID with 11½” H-90 or 11½” Reg.</td>
</tr>
<tr>
<td>18½-20</td>
<td>18½” OD x 3” ID with 15½” H-90 or 15½” Reg.</td>
</tr>
</tbody>
</table>

Wellbores smaller than 6½”, are uncommon in planned drilling programs. These are applied more commonly during work-over, deepening operations or in special cases in which small liners are set. The most serious drill collar problem in these small sizes is insufficient connection torsional strength.

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A large percentage of drilling is in wellbore sizes from 6½” inches through 8¾”. In this size range, problems are minimal. Drill collar and tool joint OD are basically the same and clearance between pipe and wellbore is usually just sufficient to allow easy wash-over operations. Practically all rigs have adequate equipment to handle the largest drill collar used in this range of wellbore sizes. The wall of the wellbore supports the drill stem very well, reducing excessive joint bending. Connections and the body of the pipe will usually withstand drilling torque developed.

Wellbore sizes from 9½” through 17½” inches require larger diameter wellbores to greater depths and much of the drilling is in medium to harder rock formations. Highly productive wells as in the Middle East require much larger production casing than normal. This is where drill collar problems increase and planning deserves extra attention. Large diameter, more difficult-to-handle drill collars are needed. The large change in cross section from drill collars to drill pipe requires an additional transitional section. More clearance between pipe and wellbore allows more flexing which accelerates fatigue damage.

The extra large sizes from 18 ½” through 26 inches currently present no unusual problems because there are not many of these wellbore sizes being drilled. Wellbores in this range rarely extend into hard rock formations. Drill collar assemblies used are normally the same that will be used in drilling the next smaller wellbore.

The difference in typical drill collar sizes used in soft and hard formation wellbores is shown in Table 2. As a rule, smaller drill collars are used in soft formation drilling because more flow area is required for higher circulation rates and sticking is a greater hazard. Most drilling will fall between the two extremes of hard or soft formations, and a mixture of practices will be found.

Transition zones

Wellbore sizes 9½” and larger require special treatment because large diameter drill collars are required on bottom for efficient drilling. A gradual transition is almost essential to reduce drill pipe fatigue damage resulting from the stiffness change. The transition zone is obtained by reducing drill collar sizes in the upper end of the drill collar string and/or by using thick-walled pipe at the bottom of the drill pipe string. Unfortunately, there is no standard that tells exactly how much stiffness change is acceptable or when trouble stops and starts. The ideal design would call for a reduction of many collars by small increments but would require too many different sizes for practical application. The transition zone design usually is based on past experience.

The 8-inch drill collar is one of the most popular sizes used today. Stiffness change from 8-inch to 41/2 or 5-inch standard weight drill pipe is very severe and it is recommended that either two or more stands of smaller collars be placed on top, or that several stands of extra thick drill pipe be run on the lower end of the drill pipe string. Drill collars 9 inches in diameter and larger should always be tapered with smaller collars on top before connecting to any...
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kind of pipe, including thick wall pipe. Typical examples of tapered strings are as follows:

- Nine 8-inch drill collars, fifteen 7-inch drill collars
- Eighteen 8-inch drill collars, 18 joints of heavy wall pipe
- Six 9-inch drill collars, twelve 7-inch drill collars
- Nine 10-inch drill collars, twelve 8-inch drill collars, 18 joints of heavy wall pipe
- Three 11-inch drill collars, six 9-inch drill collars, twelve 7-inch drill collars.

Two types of thick-walled drill pipe are available for transition sections. Conventional drill pipe can be purchased with a wall thickness of 7/16-inch for 4 OD pipe and with ½” for 5-inch. Special transition pipe with one-inch wall thickness also is available.

Selecting connections

Design of the best rotary shouldered connection for a drill collar calls for the pin and box to be balanced in bending fatigue. It has been found that the pin and box are equally strong in bending if the section modulus of the box in its critical zone is 2 ½ times greater than the section modulus of the pin at its critical zone. These zones are shown in Fig. 18.

**Fig. 18:** the section modulus, 1, of the box should be 2½ times greater than the section modulus, z, of the pin in a drill collar connection. On the right side of the connection are the spots at which the critical area of both the pin (Ar) and box (Ab) should be measured for calculating torsional strength.

In the box, it is just short of the end of the pin at the root of the last engaged thread. It is not supported by the mating pin threads and it is the weakest section in the box. The critical zone of the pin is about ¾-inch from the shoulder, at the root of the thread.

Section modulus ratios from **2.25 to 2.75** will work very well in most conditions. In some cases, satisfactory performance is experienced with ratios from 2.0 to 3.2. These numbers for bending fatigue balance are only true in service conditions if the connection is tightened properly so that the pin gets sufficient shoulder support.

The other structural property of importance is the connection’s torsional strength. Critical areas of pin and box which are used for torsional strength calculations are shown in Fig. 18. Required make-up torque is determined from torsional strength. Complete information and tables can be found in many publications for all sizes of connections and collars. A good reference is API RP 7G, “Recommended practice for drill stem designs and operating limits.”
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The difference in the treatment and properties of drill collar connections and tool joint connections is often misunderstood. A drill collar connection can never be made as strong as the drill collar body and thus is a sacrificial element—when bad, it is cut off and replaced by machining new threads. Drill pipe tool joint connections are much stiffer and stronger than the pipe and seldom experience bending fatigue damage. Tool joint connections are selected to get the best torsional strength. The most common damage occurring to tool joint threads is caused by leaking joints, handling, thread wear and swelled boxes made thin by OD wear. Damaged tool joint threads often can be reworked and returned to service by chasing the threads, thus losing only a fraction of an inch in length.

Historically, the nominal size of a rotary shouldered connection was the actual drill pipe OD that the tool joint was designed to fit. The same connections have been used on drill collars, but the size has no meaning when applied to drill collars. Recently, API numbered connections were developed and many old connections were incorporated into the new numbered series. New connections were designed to fill gaps where sizes to fit a popular diameter drill collar did not exist. The number size is simply the size of the pitch diameter in inches at the gage point of the threads rounded off to one digit past the decimal point.

For example, gage point of the pin in Fig. 19, measured 5/8” from the shoulder, is 5.616 inches giving a number size of 56. Details of numbered connections on sizes and interchangeable equivalents to old existing joints can be found in API Specification 7.

Fig. 19: in the API method of measuring or numbering connections, the diameter of the connection is measured 5/8ths of an inch from the shoulder. The measurement obtained is rounded off to the first two digits and the decimal point removed. The API number for this connection is 56.

The new numbered series gives a good selection of connections for almost any size drill collar. Any other API connection with 4 threads per inch works well. A thread with 0.038-inch root radius will have less notch effect than a thread with a smaller radius. Avoid using connections with 5 threads per inch on drill collars. The 90° threads make good drill collar connections, but relative to API threads, recommended make-up torques result in reduced shoulder loads. Higher hoop stresses are developed and thin boxes must be avoided.
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Connections for large OD collars

Good connections are designed to fit drill collars through 11-inch OD. But a problem arises in that only large rigs may have tongs and line pull capacities to handle a 7 5/8” joint that would be used on 9 or 9¾-inch drill collar. And, only a very few can handle an 8 5/8” connection on a 10 or 11” drill collar. Two methods are used to alleviate this problem. The drill collar diameter can be reduced for about one foot on the pin end and three feet on the box end, Fig. 20.

Fig. 20: special features available on drill collars include fishing or handling necks, upper left, stepped bores, lower left, and slip and elevator recesses and spiral grooves, right

For example, a 9-inch drill collar may be reduced to 8¼” for a 6.5/8” connection. A 10” drill collar may be reduced to 9¼” for a 7.5/8” connection.

Another way to lower the required make-up torque is to use a low torque face as in Fig. 21.

Fig. 21: for very large diameter collars, recommended connection torque may exceed rig capability. Thus, a low torque face is used on large diameter collars to reduce the required make-up torque

In some cases a combination of necks and low torque faces are used. The important thing to remember is that sufficient torque on a modified end and possibly smaller joint is far better than inadequate torque on a full size end and a larger joint.

Special features on threaded connections

A feature recommended without exception on all joints is cold rolling of thread roots. Cold rolling forces metal fibres into compression in the thread root area making the connection more resistant to bending fatigue. Most manufacturers universally do this on drill collars, and good repair shops are also equipped to cold roll re-cuts. Resistance to notch fatigue can always be improved and there never seems to be any adverse effects.

Fig. 22: stress relief features are recommended for drill collars 5 inches OD or larger. Stress relief features reduce torsional strength only slightly, but collars with 2 internal flush joints and smaller should not be supplied with stress relief features

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Stress relief features are highly recommended and they are almost universally used on drill collars 5 inches in diameter or larger, Fig. 22. The only disadvantage to these features is that more stock must be removed to re-cut the joint. However, a damaged drill collar joint is usually so serious that it is good practice to remove most of the old joint before re-cutting. Drill collars smaller than 5-inch OD are seldom damaged by fatigue. Most damage while in service results from high torque. Drill collars 4¾ inches OD x 2 inches ID are manufactured about equally with and without relief features. In this case, no set rules apply and conditions will dictate the preference. Stress relief features reduce torque rated strength of a connection only slightly. Magnitude of reduction is insignificant on medium and large connections. On small connections which are weak in torque for service conditions, it should be considered. Collars which have a 2 7/8” internal flush bore, or smaller joints, should never be supplied with relief features.

Special drill collar features.

Popular special features shown in Fig. 20 include fishing necks, stepped bores, slip and elevator recesses and spiral grooves. The reduced diameters on the ends are commonly called fishing necks, but they often serve another purpose. This has already been discussed in situations where necks are machined to allow smaller connections that can be torqued properly with available tongs and catheads. The name comes from the original use which was to receive an overshot and grapple in case of joint failure in the wellbore. These necks are very common in drill collars larger than 8”.

Occasionally they are used on smaller sizes when collars are selected to fit the wellbore with very close clearances.

A stepped bore is used to increase pin strength in medium and small diameter collars when large bores are needed for circulating fluid. A typical example is a 6¼” drill collar with a 2 13/16” bore reduced to 2¼” through the pin.

Slip and elevator recesses, which have become very popular in the last few years, eliminated the need for safety clamps and lift subs. Elevators are changed and drill collars can be handled like drill pipe. Caution should be exercised in the machining and repair of these recesses. It is extremely important to adhere strictly to manufacturer specifications. Satisfactory designs have been developed, but they will tolerate very little deviation without creating serious high stress problems. Recess depth, curvature on the ends, surface finish and cold rolling all are very critical. In some highly corrosive environments stress corrosion may develop in the recesses and therefore, their use is not recommended.

Spiral grooving is popular for medium and small collars used in deep drilling. The grooves offer protection against differential sticking by reducing the contact area between drill collars and wellbore wall and by allowing the hydrostatic mud pressure to equalize around the drill collars.
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Many drill collars are hard faced with tungsten carbide for areas where abrasive formations cause rapid OD wear. Hard facing is another operation in which caution must be exercised. Drill collar steel is very sensitive to quench effect and can easily be cracked or left with high residual stresses which cause cracks to form later. Proper procedures in preheating and post heating are critical.

Taking care of drill collars

Summary
To drill a good, low cost wellbore, the drill collar string must be in top condition. By knowing its causes, drill collar damage can be prevented and use of proper inspection procedures can help eliminate catastrophic failure resulting from normal wear. When damage does occur, field or machine shop repair techniques can help keep equipment costs to a minimum.

Drill collar failure
Failure of a drill collar while in service can lead to lost time, an expensive fishing job or a junked wellbore. Thus, causes of drill collar damage must be recognized and eliminated whenever possible. Since unchecked, normal wear can lead to a down-wellbore failure, drill collars should be inspected at regular intervals and defective collars removed from the string. In addition to causes of drill collar damage and inspection techniques, this article discusses procedures that can be used to repair minor drill collar damage in both the field and machine shop.

Causes of damage
Two types of vibration cause excessive damage to the drill string. One is a guitar string type whipping action in drill pipe caused by a combination of critical rotary speed and string length. This is discussed extensively in API RP 7G. The drill collar string probably is not affected by this type of vibration except that problems at the transition zone between collars and drill pipe may be intensified.

The second type of vibration occurs at the bottom of the wellbore where high and low spots cause the entire drill string to oscillate up and down at a frequency three times the rotary speed with a three cone bit. This oscillation can damage bit, drill stem and surface equipment. Bit weight and rotary speed can be altered to reduce such vibration, but this can reduce bit performance. However, down-wellbore vibration dampeners may be used to allow the bit to roll over these high and low places without vibrating the drill stem. The best place to install dampeners is directly above the bit. If special bottom-wellbore assemblies are used, dampeners will work well immediately above the assemblies.

Drill collars must be capable of supplying sufficient weight and of being rotated at whatever speed the bit requires for best performance. Bit weight reached a peak about 20 years ago at almost 10,000 pounds per inch of bit.
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diameter with short milled tooth bits in very hard formations. Fortunately, the rotary was turned only 60 rpm. This high weight created drill collar problems, but most could be controlled. Carbide insert bits have largely replaced the short milled tooth bits and they require less weight to drill. This reduced weight taxes drill collars less, but an offsetting factor requires as much or more vigilance for proper drill collar care and maintenance. Sealed bearing carbide insert bits often stay on bottom 100 hours or more and thus, crews cannot inspect threaded connections as often. To assure the drill collar string is reliable and will keep the new bits on bottom for the full run, connections must be maintained in the very best condition.

During the 1950s most soft formations were drilled with rotary speeds ranging from 150 to 200 rpm and occasionally higher, but weights were low with no more than 6 to 12 drill collars in the string. This did not create abnormal collar connection problems because the collars did not buckle excessively due to limited compressive loads applied. During the 1960s and thereafter trends used higher weights for soft formation with some decrease in rotary speed. Drill collar failure problems increased and operators then started using the same practices and inspection techniques developed for hard formations.

Present drill collar problems can largely be kept under control for all practices using roller cutter bits. Occasionally, diamond bits have reportedly been rotated as high as 400 rpm. This may create stresses above the limits of a conventional drill string, and a down-wellbore motor should be considered.

The drilling crew has an important role in making drill collars run longer, because the best designs and plans cannot overcome poor rig practice. Three important factors are:

1. Care in handling to protect the joint from damage before it goes into the wellbore 
2. Cleaning and doping with satisfactory lubricant 
3. Proper make-up torque.

Other helpful measures include a good procedure for breaking in a new string, and inspecting threads and shoulders during a trip to look for early signs of loose connections and other damage.

Most handling damage can be eliminated by keeping thread protectors on the connections until collars are picked up and ready to go into the wellbore. Bail type thread protectors should always be used when picking up and laying down collars. It is crucial that threads on lift subs be kept in good condition. Fins and burrs on lift sub threads can damage drill collar boxes and cause joints to leak, and some joints are damaged while stabbing. It is important that damaged joints be repaired before they are run in the wellbore, a bad scar on a shoulder can cause a washout and costly fishing job, Fig. 23.
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Fig. 23: If remained unnoticed, a badly dented shoulder, left, can result in a washout similar to the one shown on a pin connection, right

Connections that are not cleaned properly will trap dirt and solids in the threads and between shoulders. Proper shoulder loads cannot be developed even with the correct torque being applied, and the connection will 'behave in service as if it were loose. Cleaning threaded connections before doping can help prevent washouts. The box shoulder should be completely doped as well as the threads. Crews should not assume the dope will squeeze out to cover the shoulder.

Drill collar joint thread dope must be able to withstand very high bearing loads, and resistance to circumferential makeup must be fairly high. Values in torque tables are based on using dope with 0.08 friction factor (refer to Appendix of API RP 7G). The greatest danger is in using slick dopes, especially on medium and small joints. Slick dopes decrease torsional strength of the connections. Compounds must not have any ingredient that could be detrimental to the steel in the service environment.

API Specification 7 recommends compounds that contain 60% by weight of finely powdered lead or 40% to 60% by weight of finely powdered metallic zinc. This does not mean all other dopes are unsatisfactory, but caution should be exercised in using other types. Indiscriminate selection of thread compounds has been the cause of many drill collar connection problems.

The probability of connection problems is far greater with a newly machined thread than with one that had been run a short time, because the process of making up and breaking out toughens thread flanks and shoulders, greatly increasing resistance to galls, Fig. 24, and tears.

Fig. 24: galled shoulders can be prevented if new drill collars are made up and broken out before they are run into the hole
How to drill a usable wellbore

Connections on new collars and re-machined threads should be conditioned by a chemical etch to protect the surface during break-in. This should not be substituted for extra care in breaking in new connections. New connections should be doped properly, walked in with tongs and made up with proper torque. Then, they should be broken out immediately and the same operation repeated before going into the wellbore. Circumferential makeup will be a little greater on the second makeup because of the cold work and seating of the surfaces.

The box shoulder can be visually inspected on trips while the collar rests in the slips. A gray ring around the outside edge of the face is an early sign of inadequate shoulder load, Fig. 25.

This will develop into radial channelling and then washing if no corrective action is taken. If only discoloration is visible and no actual groove has formed, the only corrective measure usually necessary is increased makeup torque. If a groove has actually washed across the shoulder, it must be refaced before continuing in service. Threads and shoulders must be completely re-cut on bad washes.

Lack of proper makeup torque is the most common single cause of drill collar connection problems. Tables for recommended makeup torque are available in API RP 7G, IADC’s Drilling Manual and in manufacturers’ publications. Tables used should be current, since recommended torque values have been increasing as a result of changes in drilling practice.

Application of a line-pull measuring device to measure torque is relatively simple for medium and small connections, and only one or two lines are required on each tong arm. On large collars where several lines may be required, mistakes are easily made in correcting line pull to true pull on the tong arm. Crews must understand that the pull line and tong arm should be about 90 degrees when the full line pull is reached and the pull must be steady (not in jerks). The tong line hook-up should be checked for any obstructions that could resist tong movement when torque is applied. Line pull instruments should be calibrated periodically.

Ideally, makeup torque should be sufficient to prevent shoulders from separating in service. Recommended torque values have been determined from both testing and field experience. Values recommended will provide sufficient shoulder load for most conditions. Occasionally, makeup torque must be increased over recommended values for severe drilling conditions.
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‘When this is necessary, it is mandatory that no mistakes be made in determining actual connection dimensions, and torque makeup practices must be under good control. Yield strength of the steel is likely to be approached so closely that the connection easily could be damaged in the rotary table.

Collars 7 inches and larger are damaged most by inadequate makeup torque, which causes leaky joints and pin fatigue cracks. Main cause of damage to collars 5 inches and smaller is excess torque, caused by high drilling torque as well as too much make-up torque. Drill collars from 5'/2 inches to 6 inches may be affected by either problem.

Field inspection & repair

Routine field inspection of drill collar threads for fatigue cracks is now standard practice for most contractors. The preferred way to handle inspection is with trained service company personnel, but in areas where this service is not available contractors can purchase necessary equipment and train their own people to do the inspection.

The purpose of drill collar field inspection is to keep connections in service as long as possible and at the same time, minimize failures. The practice has been successful, since fatigue is usually a slow process, and inspection intervals need not be so frequent as to become impractical. Time between inspections is best determined from experience. A one month interval is typical, but adjustments should be considered depending on the number of cracks found on each inspection, or if failures occur in the wellbore. Also, fatigue cracks usually occur in a small localized area in, and adjacent to, the thread roots. Close attention can be given this critical area at reasonable costs.

The flaw detection method most suited for drill collar connections is magnetic particle inspection. A fluid containing fluorescent magnetic particles is sprayed on connections after they are carefully cleaned. If a crack is present, it is easily found by the inspector with the aid of an ultra violet light, Fig. 26.

Within the magnetic field of the drill collar, a north and south pole will be formed across the crack causing the fine metal particles to become attracted. This is especially effective in boxes, which are examined using a mirror to reflect the image at the thread root.
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Any surface discontinuity will attract iron particles and when a concentration is seen, it may not necessarily be a crack. A rolled over edge or a scratch may appear the same as a crack. However, the thread root can be polished with a very fine grinding disc and rechecked. If the indication does not appear again it probably was not a crack. Grinding is continued until the flaw can be verified as an actual fatigue crack.

Drill collar inspection is more than just a look for cracks in the threads. A thread profile check can indicate stretched pins and worn threads, Fig. 27.

Boxes are checked for swelling, Fig. 28, and shoulders are inspected for leaks, or a condition that may cause leaks.

Fig. 27; the space between the thread profile gage and threads indicates that this pin connection has been stretched

Fig. 28; swelled box connection.

Threads should not be inspected according to new manufactured thread standards. If they were, few threads would pass the test and reworking cost would be prohibitive. For this reason, stand-off gages, and lead and taper gages are not recommended as standard practice. It must be assumed that threads were made properly when first machined. The only criteria for passing a thread connection is whether it is considered safe to run in service until checked again by a qualified inspector.

A good field inspector can perform minor repairs to help keep collars running. Shoulders can be polished by re-facing tools, Fig. 29.

Fig. 29; re-facing tools can be used in the field to repair small shoulder defects

Small indentations on shoulders are not dangerous as long as they do not continue across the face. The shoulder surface is the only seal, and fins or raised spots that form frequently on the shoulder edges should not be tolerated. They can be removed in the field with a small grinder. Burrs and small galls on the threads can also be removed in this manner.
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**Shop repair**

The strength of the best threaded drill collar connection cannot possibly approach the strength of the collar body. Thus, the five or six inches of threads on each end of a new collar can be destroyed because of use whereas the material in the remaining 29 feet may be as good as new. Re-cutting damaged connections on used drill collars reduces drill collar cost to a fraction of what it would be if collars were considered completely expendable when the first connections become unusable.

A common misconception is the use of a stand-off gage alone—a stand-off gage will assure only that the connection will shoulder properly. It is essential that the lead, taper and thread profile of the connection be checked to assure full thread engagement for maximum joint strength.

Thread hobbs are available in most drill collar repair shops, Fig. 30. This machine mills the entire profile of the threads at once with a form cutter. A hobb-cut thread is recommended over a lathe-cut thread with a single point tool.

Any time a crack is found on a thread, it should be completely removed before re-cutting. The practice of chasing small cracks out and saving all possible length can be disastrous. The remaining crack cannot always be seen by the machinist, especially if it is in the box. The small value of the extra material that could be saved should be sacrificed to completely eliminate the possibility of the same crack recurring. Also, cold rolling equipment should be used.

Many areas have no problems, except that connections are re-cut until the stand of collars becomes too short to rack in the derrick. In these areas, it is not uncommon for collars to last three years or more.

Drill collars that become too short can be stub welded successfully and restored to their original length. Proper welding procedures must be used—stub welds should always be made in the full diameter of the collar.

Connections or reduced diameters such as slip and elevator recesses should never be machined into an old stub weld. If it is suspected that an old weld exists, it should be located using an acid etch.

In some abrasive formations, OD wear can be as much as \(\frac{1}{4}\)-inch in six months. Collars with heavy OD wear and thin boxes can sometimes be re-machined to a smaller joint size and continue to give good service.

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A good way to salvage a collar with excessive wear and insufficient length is to stub weld using a smaller bore on the pin and to make a stepped bore collar. These worn collars have two possible applications;

1. some times used in smaller wellbore sizes

2. On the top of newer, full size collars to give a better transition to drillpipe.

Minimum drilling costs and a good usable wellbore will be obtained only when the correct drill string is selected for the job and when good equipment care and maintenance practices are followed.