Wellbore Integrity
SOLUTIONS

DRILCO

DRILLING ASSEMBLY HANDBOOK

DRILLING ASSEMBLY HANDBOOK

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DRILCO

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Preface

This handbook was prepared by Wellbore Integrity Solutions DRILCO engineers to help rig personnel with technical questions, provide recommendations and help the rig crew to optimize their drilling operations.

It summarizes proven drilling techniques and technical data that will enable the drilling rig staff to drill a usable well at the lowest possible cost. It is designed in a size to allow it to be carried in a hip pocket for quick, easy reference.

If there are any questions about the Drilling Handbook, contact your nearest DRILCO representative or talk with our service people when they visit your rig or fill out the contact us information at **wellboreintegrity.com**.

How to Use This Handbook

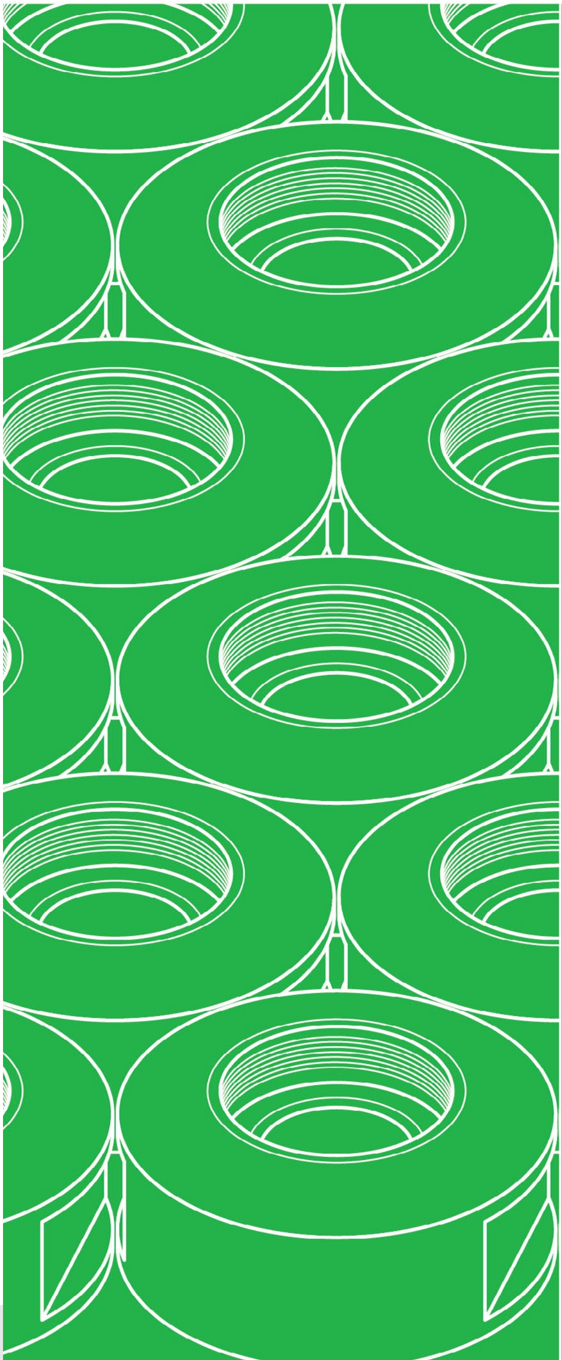
The DRILCO Drilling Assembly Handbook is divided into eight (8) major sections, that are described in the table of contents.

A detailed index is also provided starting on page 169. The topics in the index will give the page numbers of information relating to specific drilling problems which might be faced on the rig floor.

SECTION ONE

BOTTOMHOLE ASSEMBLIES

1



BOTTOMHOLE ASSEMBLIES

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Introductory Comments on Bottomhole Assemblies

The title of this publication is DRILCO Drilling Assembly Handbook. The following pages are devoted to the entire drilling assembly, from the swivel to the drill bit. Useful information about the rotary shouldered connections (pins and boxes) that are used on every drill stem member has also been included.

The primary content in this section is the bottomhole assembly (BHA) — the tools between the bit and the drillpipe. Over time, the BHA has grown from one or two simple drill collars to a complex array of tools above the bit. Today the BHA is typically about 500 to 1,000 ft (150 to 300 m) long.

The purpose of this pocket sized rig floor handbook is to simplify the complexities of the tools that makeup the BHA. This handbook explains the purpose of each tool, how to select and proper assembly procedures for maximum effectiveness and minimum trouble.

Today the BHA serves several useful purposes, in addition to the simple need to effectively load the bit with drill collar weight. Correctly designed, the BHA can:

- Prevent doglegs and keyseats.
- Produce a smooth bore and full size borehole.
- Improve drillbit performance.
- Minimize drilling problems.
- Minimize harmful shock and vibration.
- Minimize differential pressure sticking.
- Reduce post-drilling production problems.

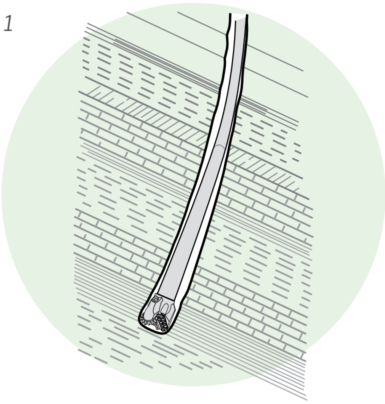
In the following pages this handbook explains how these desirable objectives can be attained.

BOTTOMHOLE ASSEMBLIES

Straight Hole Drilling

An alternate title for this handbook could have been Controlled Deviation Drilling since it is now known that a perfectly straight hole is virtually impossible to drill. No one knows the exact cause of holes being drilled crooked but some of the most significant theories are presented in this handbook. It has been confirmed that the drill bit will try to climb uphill or updip in laminar formations with dips to 40° (Fig. 1).

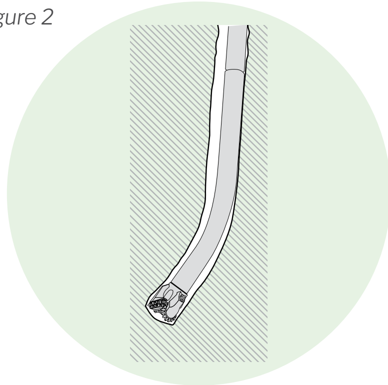
Figure 1



Another factor to consider is the bending characteristics of the drillstring. With no weight on the bit, the only force acting on the bit is the result of the weight of the portion of the string between the bit and the tangency point. This force tends to bring the hole toward vertical. When weight is applied, there is another force on the bit which tends to direct the hole away from vertical. The resultant of these two forces may be in a direction as to increase angle, to decrease angle or to maintain a constant angle. This was stated by Arthur Lubinski (research engineer for Amoco) as far back as the spring meeting of the Mid-Continent District, Division of Production, in Tulsa, OK in March 1953, and was based upon the assumption that the drillstring lies on the low side of an inclined hole (Fig. 2).

In general, it is well known that it is easier to drill a hole in soft formations than in hard formations. In particular, the effects of the drillstring bending are much less when drilling soft formations, since harder formations require higher weight on bit (WOB).

Figure 2



In a straight hole drilling contract, many of the possible crooked hole troubles can be prevented by obtaining satisfactory contract terms on deviation and doglegs. It is extremely important, when negotiating the contract, that the operator be aware of the advantages of giving the broadest possible limits for hole deviation. By relaxing deviation clauses to reasonable limits, it is possible to drill a reasonably straight hole at high rates of penetration and avoid the costly operations of plugging back and straightening the hole. In addition to the operators' deviation limits, it may be possible to work with the operator to select a well site location so that the well may be allowed to drift into the target area. If the plan is to reach a certain point on the structure, and it is known that the well will drift in a certain direction up-structure, it is desirable to move the location down-dip so, when drilling normally, the bottom of the well will drift into the target area.

From the drilling contractor's standpoint, valuable time can be spent in planning the drillstring and the bit program along with the hydraulics.

Drift planning will include obtaining the largest drill collars that may be safely run in a given hole size and selecting optimum bit weights to get the best rate of penetration. If it is anticipated that there will be a problem maintaining the deviation within the contract limits, there are more extreme methods available which will assure a wellbore that is more nearly vertical and still allow relatively high rates of penetration.

Arthur Lubinski and Henry Woods (research engineers for the Hughes Tool Co.) were among the first to apply mathematics to drilling. They stated in the early 1950s that the size of the bottom drill collars would be the limiting factor for lateral movement of the bit, and the minimum effective hole diameter (MEHD) could be calculated using the following equation:

$$\text{MEHD} = \frac{\text{bit size} + \text{drill collar OD}}{2}$$

Robert S. Hoch (engineer for Conoco Phillips Petroleum Company) theorized that, while drilling with an unstable bit, an abrupt change can occur if hard ledges are encountered (Fig. 3). He pointed out that a dogleg of this nature would cause an undersized hole, making it difficult or nearly impossible to run casing. Hoch rewrote Lubinski's equation to solve for the minimum permissible bottomhole drill collar OD (MPBHDCOD), as follows:

MPBHDCOD = 2 (casing coupling OD) – bit OD

For example:
Data: 12¼-in. bit
9⅝-in. casing (coupling OD = 10.625 in.)

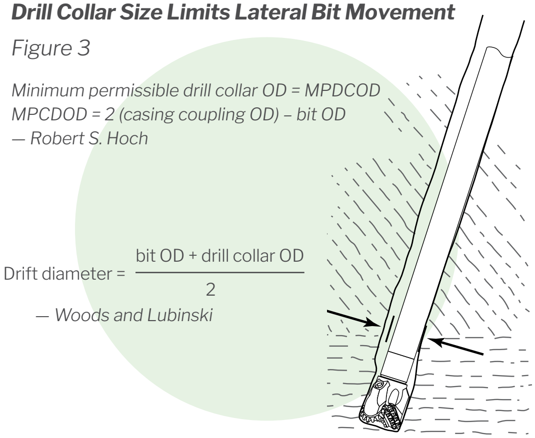
Minimum drill collar size = 2 (10.625) - 12.250
= 9-in. OD

Data: 311.2 mm bit
244.5 mm casing (coupling OD = 269.9 mm)

Minimum drill collar size = 2 (269.9) - 311.2
= 228.6-mm OD

Drill Collar Size Limits Lateral Bit Movement

Figure 3

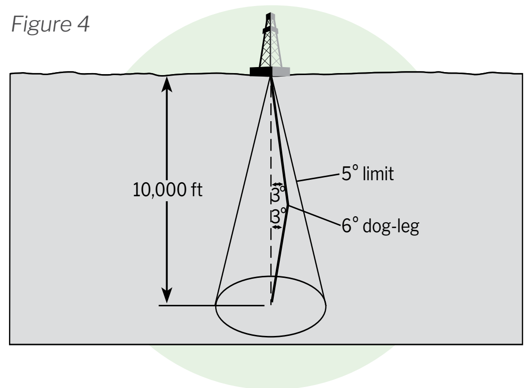


Total Hole Angle

Total hole angle should be restricted (1) to stay on a particular lease and not drift over into adjacent property; (2) to ensure drilling into a specific pay zone like a stratigraphic trap, a lensing sand, a fault block, etc.; (3) to drill a near vertical hole to meet legal requirements from regulatory agencies, field rules, etc.

The restriction of total hole angle may solve some problems but it is not a cure-all. Figure 4, the typical 5° limit does not assure a wellbore free of troublesome doglegs.

Figure 4



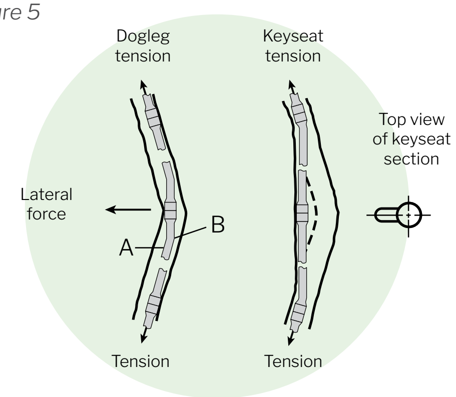
Restricting Rate of Hole Angle Change

Lubinski pointed out in his work in the early 1960s that the rate of hole angle change should be the main concern, not necessarily the maximum hole angle. He expressed this rate of hole angle change in degrees per 100 ft. In 1961 an American Petroleum Institute (API) study group published a tabular method of determining maximum permissible doglegs that would be acceptable in rotary drilling and completions. Consequently, the main objective is to drill a useful hole with a full-gauge, smooth bore, free from doglegs, keyseats, offsets, spirals and ledges.

A keyseat is formed after part of the drillpipe string has passed through the dogleg. Since the drillpipe is in tension, it is trying to straighten itself while going around the dogleg. This creates a lateral force that causes the drillpipe to cut into the center of the bow as it is rotated (Fig. 5). This force is proportional to the amount of drillstring weight hanging below the dogleg. A keyseat will be formed only if the formation is soft enough and the lateral force great enough to allow penetration of the drillpipe. When severe doglegs and keyseats are formed, many problems can develop.

BOTTOMHOLE ASSEMBLIES

Figure 5



Problems Associated with Doglegs and Keyseats

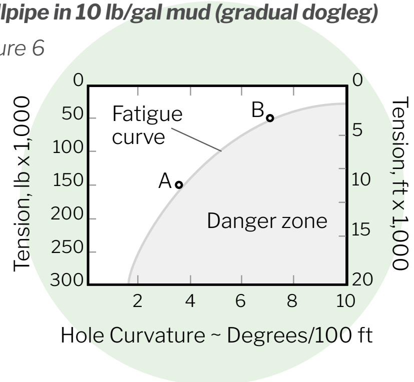
Drillpipe Fatigue

Lubinski presented guidelines in 1961 for the rate of change of hole angles. He said that if a program is designed in such a way that drillpipe damage is avoided while drilling the hole, then the hole will be acceptable for conventional designs of casing, tubing and sucker rod strings as far as dogleg severity is concerned. A classical example of a severe dogleg condition which produces fatigue failures in drillpipe can be seen in Figure 5. The stress at Point B is greater than the stress at Point A; but as the pipe is rotated, Point A moves from the inside of the bend to the outside and back to the inside again. Every fiber on the pipe goes from minimum tension to maximum tension and back to minimum tension. Cyclic stress reversals of this nature cause fatigue failures in drillpipe, usually within the first two feet of the pipe body adjacent to the tool joint, due to the abrupt change of pipe cross section.

Lubinski suggested that to avoid rapid fatigue failure of the pipe, the rate of change of the hole angle must be controlled. Suggested limits can be seen in Figure 6. This graph is a plot of the tension in the pipe versus change in hole angle in degrees per 100 ft (30.5 m). This curve is designed for 4½-in., 16.60 lb/ft (114.3-mm, 24.7 kg/m) Grade E drillpipe in 10 lb/gal (1.2 g/cc) mud. The curve represents stress endurance limits of the drillpipe under various tensile loads and in various rates of change in hole angle. If conditions fall to the left of this curve, fatigue damage to the drillpipe will be avoided. To the right of the curve, fatigue damage will build up rapidly and failure of the pipe is likely. It can be seen from this plot that if a dogleg is high in the hole, with high tension in the pipe, only a small change in angle can be tolerated. Conversely, if the dogleg is close to total depth, tension in the pipe will be low and a larger change in angle can be tolerated.

Endurance Limit for 4½-in., 16.60 lb/ft Grade E Drillpipe in 10 lb/gal mud (gradual dogleg)

Figure 6



If the stress endurance limit of the drillpipe is exceeded due to rotation through a dogleg, an expensive fishing job or a junked hole could develop.

Stuck Pipe

Sticking can occur by sloughing or heaving of the hole and by pulling the large OD drill collars into a keyseat while pulling the drillstring out of the hole.

Logging

Wireline logging tool strings can become stuck in keyseats. The wall of the hole can also be damaged, causing hole problems.

Running Casing

Running casing through a dogleg can be a very serious problem. If the casing becomes stuck in the dogleg, it will not extend into and through the production zone. This problem could make it necessary to drill out the shoe and set a smaller size casing through the production interval. Even if running the casing to the bottom of the hole through the dogleg is successful, the casing might be severely damaged and prevent the installation of production (tubing completion) equipment.

Cementing

The dogleg will force the casing over tightly against the wall of the openhole, leaving a partial microannulus, prevent a proper fill and eliminate a good cement bond since no cement cannot circulate between the wall of the hole and the casing at this point.

BOTTOMHOLE ASSEMBLIES

Casing Wear While Drilling

The lateral force of the drillpipe rotating against the casing in the dogleg or dragging through it while tripping the drillstring can cause a hole to wear through the casing wall. This could cause drilling problems and/or a possible blowouts.

Production Problems

It is better to have a smooth string of casing to produce through. 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.

Hole Angle Control

Now that the possible causes of bit deviation and the problems associated with crooked holes are known, two possible solutions using the pendulum and the packed hole concepts can be considered.

Pendulum Theory

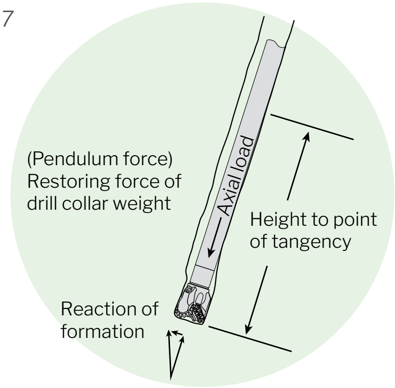
In the early 1950s, Woods and Lubinski collaborated in mathematical examination of the forces on a rock bit when drilling in an inclined hole. In order to make their calculations, they made three basic assumptions:

1. The bit is like a ball and socket joint, free to turn, but laterally restrained.
2. The drill collars lie on the low side of the hole and will remain stable on the low side of the hole.
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 that act on the bit can be resolved into:

1. The axial load supplied by the weight of the drill collars.
2. The lateral force — the weight of the drill collar between the bit and the first point of contact with the wall of the hole by the drill collar (pendulum force). Pendulum force is the tendency of the unsupported length of drill collar to swing over against the low side of the hole due to gravity. This is the only force that tends to bring the hole back toward vertical (Fig. 7).
3. The reaction of the formation to these loads may be resolved into two forces — one parallel to the axis of the hole and one perpendicular to the axis of the hole.

Figure 7



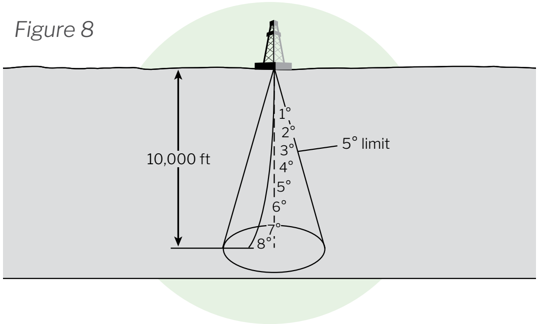
Woods and Lubinski work made it possible to utilize gravity as a means of controlling change in the hole angle. Special tables were prepared to show the necessary weight for the bit to maintain a certain hole angle. These tables also show the proper placement of a stabilizer to give the maximum pendulum force and the maximum weight for the bit. The effects of using larger drill collars can also be determined.

The tables and/or graphs can be obtained from your DRILCO representative.

Packed Hole Theory

Most operators today use a packed hole assembly to overcome crooked hole problems and the pendulum is used only as a corrective measure to reduce angle when the maximum permissible deviation has been reached. The packed hole assembly is sometimes referred to as the gun barrel approach because a series of stabilizers is used in the hole already drilled to guide the bit straight ahead. The objective is to select a BHA to be run above the bit with the necessary stiffness and wall contact tools to force the bit to drill in the general direction of the hole already drilled. If the proper selection of drill collars and bottomhole tools is made, only gradual changes in hole angle will develop. This should create a useful hole with a full-gauge and smooth bore, free from doglegs, keyseats, offsets, spirals and ledges to make it possible to easily complete and produce the well (Fig. 8).

Figure 8



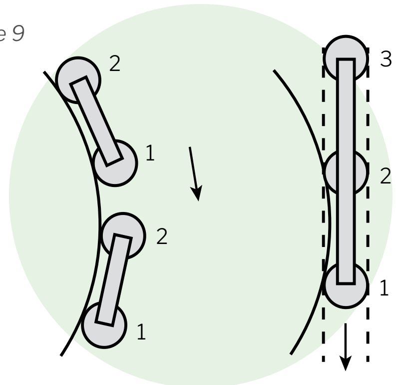
Factors to Consider When Designing a Packed Hole Assembly

Length of Tool Assembly

It is important that wall contact assemblies provide sufficient length of contact to assure alignment with the hole 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 unstabilized collars above will cause the bit to push to one side as weight is applied. Another stabilizing point, for example, at 30 ft (10 m) above the bit will nullify some of the fulcrum effect. With these two points, this assembly will stabilize the bit and reduce the tendency to build hole angle. It is, however, not considered the best packed hole assembly.

Two points will contact and follow a curved line (Fig. 9). But add one more point with a stiff assembly, and there is no way you can get three points to contact and follow a sharp curve. Therefore, three or more stabilizing points are needed to form a packed hole assembly.

Figure 9



Stiffness

Stiffness is probably the most misunderstood point when considering drill collars. Few people realize the importance of diameter and its relationship to stiffness. If you double the diameter of a bar, its stiffness is increased 16 times.

As an example, if an 8-in. (203.2-mm) diameter bar is deflected 1-in. (25.4 mm) under a certain load, a 4-in. (101.6-mm) diameter bar will deflect 16-in. (406.4 mm) under the same load.

The table below provides examples of moments of Inertia (I), proportional to stiffness. They represent the stiffness of popular drill collars of various diameters.

OD, in.	ID, in.	I, $in.^4$	OD, in.	ID, in.	I, $in.^4$	OD, in.	ID, in.	I, $in.^4$
5	2¼	29	6¾	2¼	100	9	2¹³⁄₁₆	318
6¼	2¼	74	7	2¹³⁄₁₆	115	10	3	486
6½	2¼	86	8	2¹³⁄₁₆	198	11	3	713

Large diameter drill collars will help provide greater 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-in. (241.3-mm) diameter drill collar is four times stiffer than a 7-in. (177.8-mm) diameter drill collar and is two times stiffer than an 8-in. (203.2-mm) diameter drill collar while all three sizes may be considered appropriate for drilling a 12¼-in. (311.2-mm) hole.

Clearance

A minimum clearance between the wall of the hole and the stabilizers is required for optimal operation. The closer the stabilizer is to the bit, the more exacting the clearance requirements are. If, for example, 1⁄16-in. (1.6-mm) undergauge from hole diameter is satisfactory just above the bit, then 60 ft (18.3 m) above the bit, ⅛-in. (3.2-mm) clearance may be more appropriate. In some areas, wear on contact tools and clearance can be a critical factor for a packed hole assembly.

Wall Support and the Length of Tool Contact

BHAs must adequately contact the wall of the hole to stabilize the bit and centralize the drill collars. The length of contact needed between the tool and the wall of the hole will be determined by the formation. The surface area in contact must be sufficient to prevent the stabilizing tool from digging into the borehole wall. If this should happen, stabilization would be lost and the hole trajectory would drift. If the formation is strong, hard and uniform, a short narrow stabilizer contact surface is recommended and will ensure proper stabilization. On the other hand, if the formation is soft and unconsolidated, a long blade stabilizer will be required. Hole enlargements in formations that erode quickly tend to reduce effective alignment of the BHA. This problem can be reduced by controlling the annular velocity of the drilling fluid and mud properties.

Packed Hole Assemblies

Proper design of a packed hole assembly requires a knowledge of the crooked hole tendencies and drillability of the formations being drilled in each particular area. For bas Mild crooked hole country

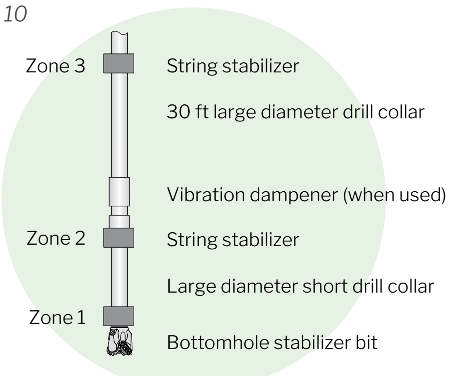
- Medium crooked hole country
- Severe crooked hole country
- Formation firmness:
- Hard to medium-hard formations
- Abrasive
- Non-abrasive
- Medium-hard to soft formations

Mild Crooked Hole Country

The packed hole assembly shown in Figure 10 for mild crooked hole country is considered the minimal assembly for straight hole drilling and bit stabilization. Three points or zones of stabilization are provided by Zone 1 immediately above the bit, Zone 2 above the large diameter short drill collar and Zone 3 atop a standard length large diameter collar. A vibration dampener, when used, should be placed above Zone 2 for the best performance. In very mild crooked hole country the vibration dampener may be run in the 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 drill bit. Wear and tear on the drilling rig and drillstring will also be reduced.

Mild Crooked Hole Country (Minimal Assembly)

Figure 10



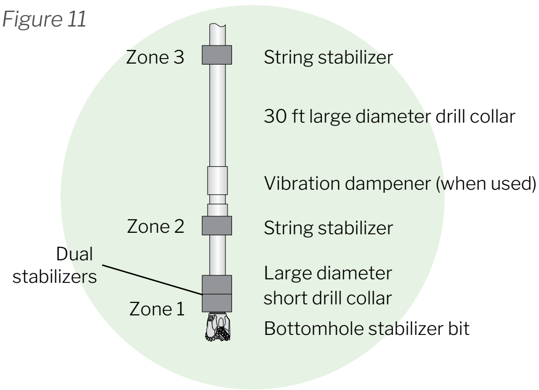
Note: In very mild crooked hole country the vibration dampener may be run in place of the short drill collar.

Medium Crooked Hole Country

A packed hole assembly for medium crooked hole country is similar to that for mild crooked hole conditions but with the addition of a second stabilizing tool in Zone 1. The two tools run in tandem provide increased stabilization of the bit and add stiffness to limit angle changes caused by lateral forces (Fig. 11).

Medium Crooked Hole Country

Figure 11

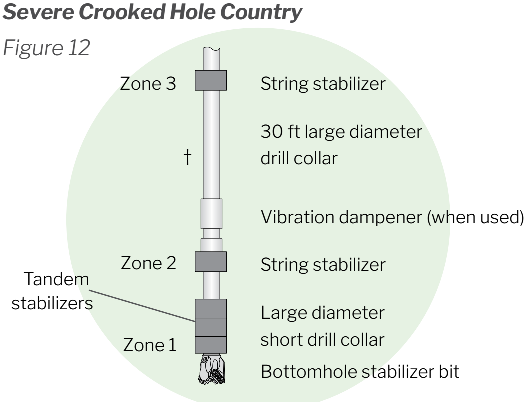


Severe Crooked Hole Country

In severe crooked hole country three stabilization tools are run in tandem in Zone 1 to provide maximum stiffness and wall contact to aim and guide the bit. In 8¾-in. (222.3-mm) and smaller hole sizes, it is also recommended that a large diameter short collar be used between Zone 2 and Zone 3. This will increase stiffness by reducing the deflection of the total assembly. It will allow the tools in Zone 1 and Zone 2 to perform their function without excessive wear due to lateral thrust or side-loading from excess deflection above (Fig. 12).

Severe Crooked Hole Country

Figure 12



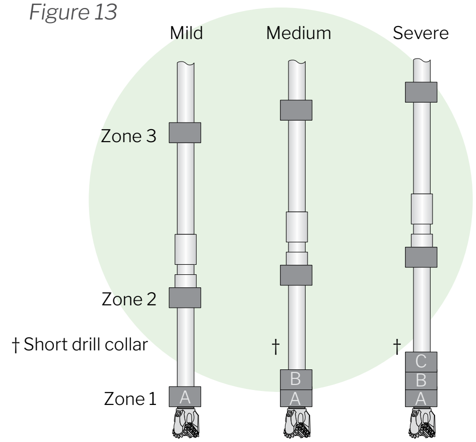
†**Note:** Use short drill collar in 8¾ in and smaller holes

Mild, Medium and Severe Crooked Hole Country

Figure 13 shows all three basic assemblies required to provide the necessary stiffness and stabilization for a packed hole assembly. A short drill collar is used between Zone 1 and Zone 2 to reduce the amount of deflection caused by the drill collar weight.

As a general rule, the numerical value of a short drill collar length (in feet) is approximately equal to the numerical value of the hole size (in inches), plus or minus 2 ft. As an example, a short collar length of 6 to 10 ft would be satisfactory in an 8-in. hole.

Figure 13



† The short drill collar length is determined by the hole size.
Hole size(in) = short drill collar (ft) ± 2 ft. Example: Use approximately an 8 ft collar in an 8-in diameter hole.

The rule of thumb for the short drill collar length in meters is equal to 12 times the diameter of the hole in meters, plus or minus 0.6 m. For example: a short collar length of 1.8 to 3.0 m would be satisfactory in a 203.2- mm hole.

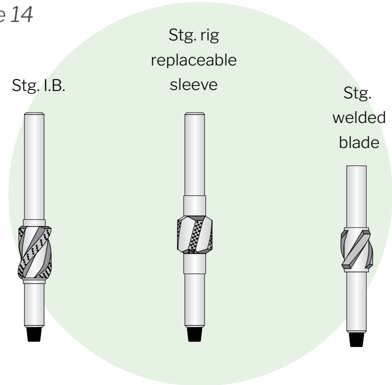
Stabilizing Tools

There are three basic types of stabilizing tools: (1) rotating blade, (2) non-rotating sleeve and (3) rolling cutter reamer. Some variations of these tools are as follows:

1. Rotating Blade

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. 14). The rotating blade stabilizers (Fig. 14) are available in two types: (a) shop repairable and (b) rig repairable.

Figure 14



a. Shop repairable

The shop repairable tools are either integral blade, welded blade or shrunk 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.

b. Rig repairable

Rig repairable stabilizers have a replaceable metal sleeve like the Ezy-Change* stabilizer. These tools were originally developed for remote locations but are now used in most areas of the world.

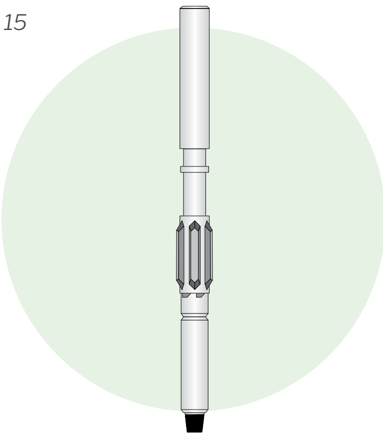
All rotating stabilizers have moderate to good reaming ability and improvements in hardfacing now provide very good wear life. Some of the hardfacing materials used are:

- Granular tungsten carbide.
- Crushed sintered tungsten carbide.
- Sintered tungsten carbide (inlaid).
- Pressed-in sintered tungsten carbide compacts.
- Diamond-enhanced pressed-in carbide compacts.

2. Rig Replaceable Non-Rotating Sleeve Stabilizer

The non-rotating sleeve tool is a very popular stabilizer since it is the safest tool to run from the standpoint of sticking and washover. This stabilizer type is most effective in areas of hard formations such as limestone and dolomite. Since the sleeve is stationary, it acts like a drill bushing; consequently, it will not dig into and damage the hole wall, although this stabilizer type does have limitations. The sleeve is not recommended for use in temperatures over 250 degF (121 degC), it has no reaming ability and sleeve life may be short in holes with rough walls (Fig. 15).

Figure 15

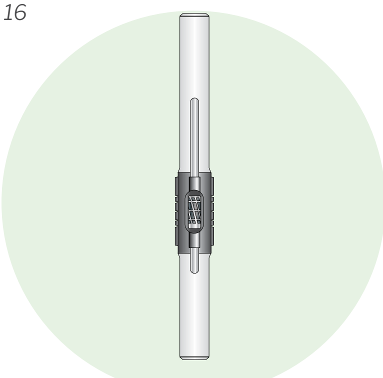


Non-rotating stabilizer

3. Rolling Cutter Reamer

Rolling cutter reamers 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. Anytime rock bit gauge problems are encountered, the lowest contact tool should definitely be a rolling cutter reamer (Fig. 16).

Figure 16



3 point BH reamer

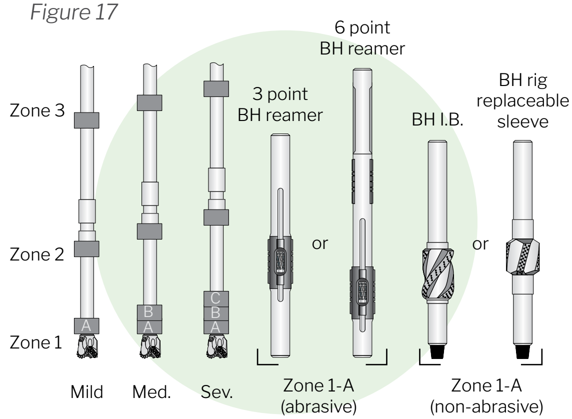
BOTTOMHOLE ASSEMBLIES

Mild, Medium and Severe Crooked Hole Country in Hard to Medium-Hard Formations

In Zone 1-A (directly above the bit), a rolling cutter reamer (Fig. 17) should be used when bit gauge is a problem in hard and abrasive formations. A six-point tool is required for extreme conditions. In non-abrasive formations, some type of rotating blade tool with hardfacing is desirable.

Mild, Medium and Severe Crooked Hole Country Hard to Medium-Hard Formations

Figure 17



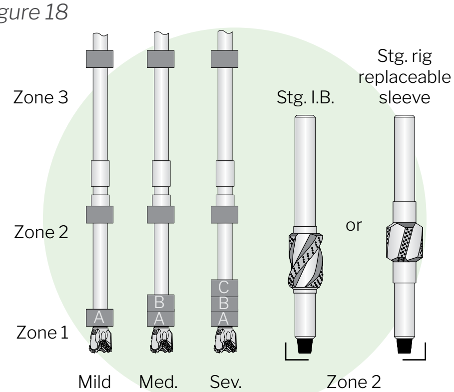
Note: Use a reamer if the bit gauge is a problem. Use a 6 point in extremely hard and abrasive formations.

Rotating blade-type tools are effective in Zone 2 for all three conditions of crooked hole tendencies. In very mild crooked hole country, a non-rotating sleeve-type tool is appropriate for use (Fig. 18).

Mild, Medium and Severe Crooked Hole Country

Hard to Medium-Hard Formations

Figure 18

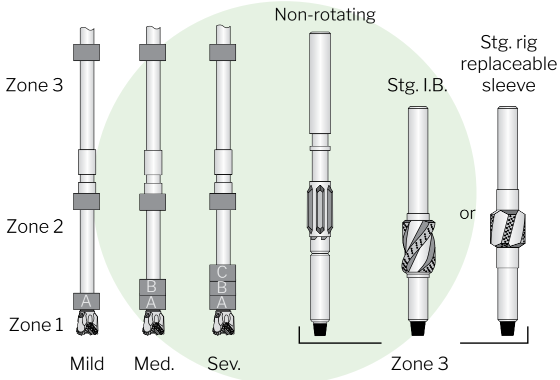


Note: In very mild crooked hole country, a non-rotation stabilizer may be used in Zone 2.

With the slightest deviation from vertical, drill collars will lie on the low side of the hole because of their tremendous weight. Therefore, the function of Zone 3 is to centralize the drill collars above Zone 2. Both the rotating blade and the non-rotating sleeve stabilizers may be used for this job in hard to medium-hard formations (Fig. 19).

Mild, Medium and Severe Crooked Hole Country Hard to Medium-Hard Formations

Figure 19



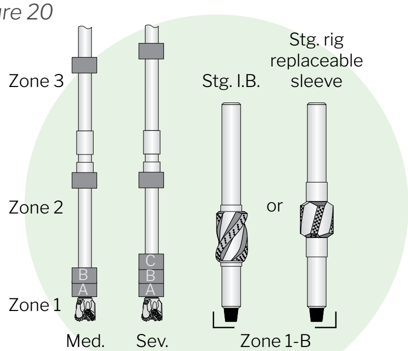
Any stabilizers run above Zone 3 are used only to prevent the drill collars from buckling or becoming wall stuck, and in most cases, will have very little effect on directing the bit.

Medium and Severe Crooked Hole Country in Hard to Medium-Hard Formations

Figure 20 shows that a rotating blade type stabilizer is recommended in Zone 1-B with hard to medium-hard formations and medium to severe crooked hole tendencies. For severe crooked hole drilling, any of the same types of tools used in Zone 1-B can be used in Zone 1-C.

Mild, Medium and Severe Crooked Hole Country Hard to Medium-Hard Formations

Figure 20



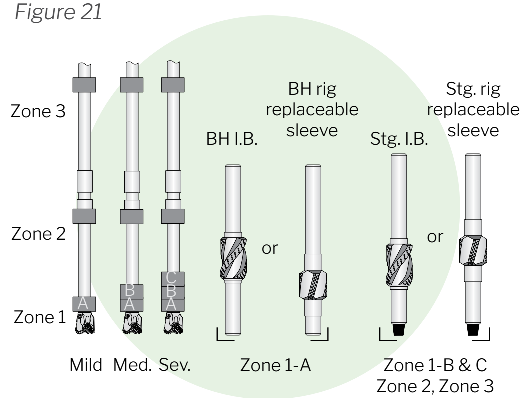
Note: The same tools would be used in Zone 1-C for severe crooked hole country.

Mild, Medium and Severe Crooked Hole Country in Medium-Hard to Soft Formations

In holes where bit gauge is not a problem, tools for use in medium-hard to soft formations must provide the maximum length of wall contact to provide proper stabilization to the drill collars and bit. For all degrees of crooked hole tendencies, rotating blade stabilizers are recommended (Fig. 21).

Mild, Medium and Severe Crooked Hole Country Medium-Hard to Soft Formations

Figure 21



Current packed hole assemblies, when properly designed and used, will:

1. Reduce rate of the hole angle change. A smooth walled hole with gradual angle change is more conducive to work through than one drilled at minimum hole angle with many ledges, offsets and sharp angle changes.
2. Improve bit performance and life by forcing the bit to rotate on a true axis about its design center to load all cones equally.
3. Improve hole conditions for drilling, logging and running casing. Maximize casing size that can be run to bottom.
4. Allow use of more drilling weight through formations which cause abnormal drift.
5. Maintain desired hole angle and course in directional drilling. In these controlled situations, high angles can be drilled with minimum danger of key-seating or excessive pipe wear.

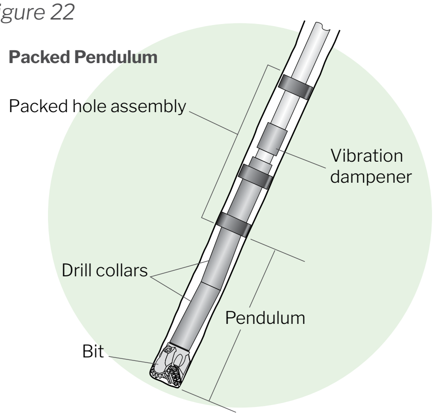
Packed Pendulum

Because all packed hole assemblies will bend no matter how small the amount of deflection a perfectly vertical hole is not possible. The rate of hole angle change should be kept to a minimum but occasionally conditions will arise where total hole deviation must be further reduced. When this does occurs, the pendulum technique is employed. If it is anticipated that the packed hole assembly will be required after reduction of the hole angle, the packed pendulum technique is recommended.

In the packed pendulum technique, the pendulum collars are swung below the regular packed hole assembly. When hole deviation has been reduced to an acceptable limit, the pendulum collars are removed and the packed hole assembly is again 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 position during the pendulum operations (Fig. 22).

Figure 22

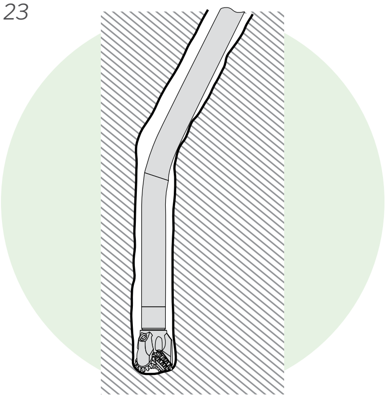


BOTTOMHOLE ASSEMBLIES

Reduced Bit Weights

One of the most common techniques for straightening a hole is to reduce the weight on the bit and increase the rotary table or top-drive speed. By reducing the weight on the bit, the bending characteristics of the drillstring are changed and the hole tends to drill straighter. It has been found that this is not always the best procedure because reducing the bit weight sacrifices rate of penetration considerably. Worse, it frequently causes doglegs as illustrated (Fig. 23.) As a point of caution, the straightening of a hole by reducing bit weight should be done very gradually so the hole will tend to return to vertical without sharp bends and will be much safer for future drilling. A reduction of bit weight is usually required when changing from a packed hole assembly to a pendulum or packed pendulum drilling operation. An undergauge stabilizer is sometimes run immediately above the bit to prevent reducing hole angle too quickly.

Figure 23



Conclusion

A well-engineered BHA, with the proper selection of stabilizing tools in all three zones, should produce a useful hole with a fullgauge, smooth bore free from doglegs, keyseats, offsets, spirals and ledges making it possible to easily complete and produce the well. Both the drilling contractor and operating company should realize additional profits from a well-planned program. A carefully planned drilling program will usually provide the best drillstring for a given job.

Downhole Vibrations

DRILCO began to market the first successful downhole vibration dampener in 1959, the Shock Sub* impact and vibration reduction sub, to meet very obvious needs at the time. Drillers were having 10 to 15 drill collar failures per well in 12¼-in. (311.2-mm) holes going to depths of 6,000 ft (1,830 m) in a rough-running area. Ordinary measures failed to solve the problem. Introduction of the vibration dampener brought about three immediate benefits. First, after the Shock Sub was introduced to the drillstring drill collar failures were reduced.

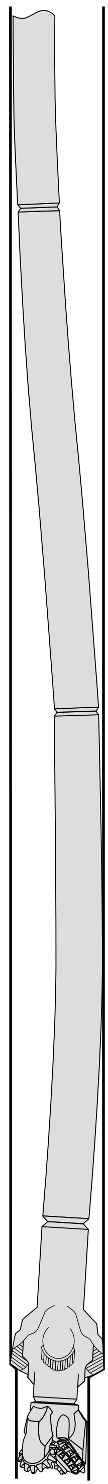
A second benefit of the introduction of vibration dampeners was increased bit life. The third benefit was achieved by increasing both rotary speed and bit weight which resulted in increases in daily drilling depth. In rough-running areas, the downhole vibration dampener has become a way of life and its use has gained worldwide acceptance.

Downhole data collected by MWD and LWD tools now provide a glimpse of what really goes on at the bottom of the hole. Using this BHA instrumentation provides useful measurements such as, bit weight, rotary speed, vertical vibrations and bending stress in the sub as well as aiding geosteering and LWD .

Without the driller even being aware at the surface, small changes in such things as rotary speed, bit weight or formation can cause serious drillstring gyrations to occur at the bottom of the hole. Vibrations develop that cause impact loads on the bit several times the load indicated at the surface. Bending loads in the sub increase by as much as 10 times.

These events indicate how vague our knowledge of downhole dynamics really is. Over the years, the drilling industry has learned to cope with these dynamics to some degree and has developed tools to run in the BHA to help monitor these events and help prevent potential problems.

BOTTOMHOLE ASSEMBLIES



Improve Hole Opener Performance by Using a Shock Sub and Stabilizers

Hole opening performance can improve with the use of a vibration dampener and a stabilizer.

1. Stabilizer

A stabilizer placed at 60 ft (18.3 m) and 90 ft (27.4 m) in the drillstring will help to minimize drill collar bending.

2. Drill Collar

Higher stress concentrations exist in the connection. Add to this bouncing of the drillstring caused by rough running and the result can be drill collar connection failures.

3. Stabilizers

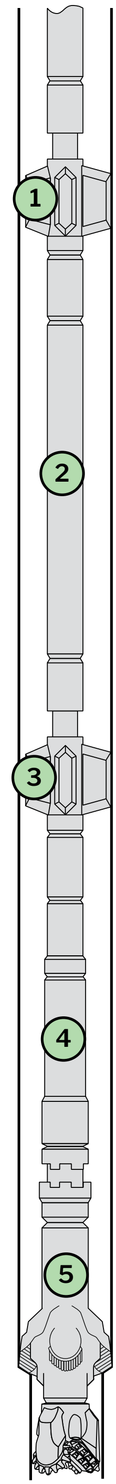
A stabilizer will center the drill collars in the hole above the hole opener and more uniformly distribute the load on the cutters in the bit.

4. Shock Sub

A Shock Sub* vibration dampener will minimize vibrations caused by the hole opener stumbling over broken formations and reduce the shock loads on the cutters and the drill collars.

5. Hole Openers

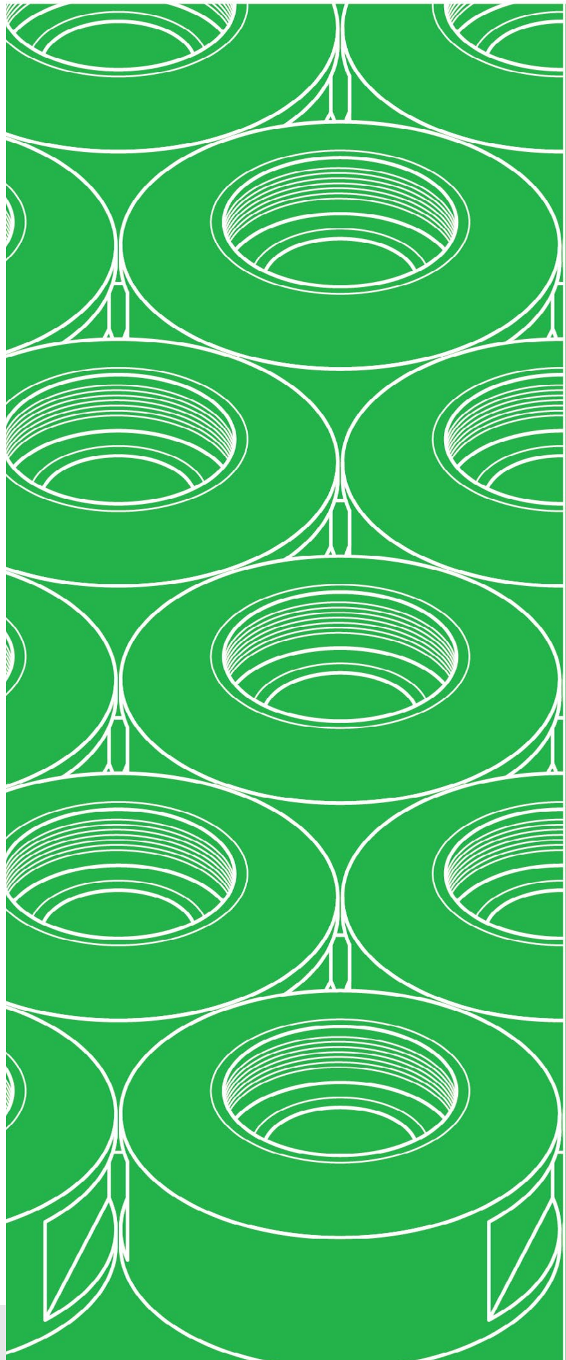
The collars are so much smaller than the hole, they bend and whip, loading first one cutter, and then the next. They put substantial side load on the pilot bit and the hole opener body. The vibration dampener, with the stabilizer, can help eliminate this side loading.



SECTION TWO

DIFFERENTIAL PRESSURE STICKING

2



DIFFERENTIAL PRESSURE STICKING

DIFFERENTIAL PRESSURE STICKING

DIFFERENTIAL PRESSURE STICKING OF DRILLPIPE AND DRILL COLLARS

Differential wall sticking is caused by the drillpipe or drill collars blocking the flow of fluid from the borehole into the formation. In a permeable formations, where the mud column hydrostatic head is higher than the pressure in the formation, the fluid loss can be considerable. Associated with the flow of fluid into the formation is a filtering of solids at the borehole wall and a resultant build up of filter cake. The smooth surfaces of the tools, assisted by the sealing effect of the filter cake, form an effective block to fluid losses into the formation. Depending on length of the blocked area, and the differences in borehole and formation pressures, this blockage of fluid flow may permit extremely high forces to build up against the tools in the hole, and the drillstring may become differentially stuck.

The use of a packed hole assembly will eliminate many of the conditions which result in sticking of the drillstring by holding the string off the wall of the borehole. Such bit stabilizing assemblies also help prevent sudden hole angle changes, offsets and doglegs which lead to sticking the drillstring in keyseats.

Reducing Differential Pressure Sticking

Differential pressure sticking can be effectively reduced by using the following tools:

Hevi-Wate* Drillpipe

The tool joints at the ends and the integral upset in the center of the tube (Fig. 24) act as centralizers to hold the heavy-wall tube sections off the wall of the hole. (For more information see page 115.)

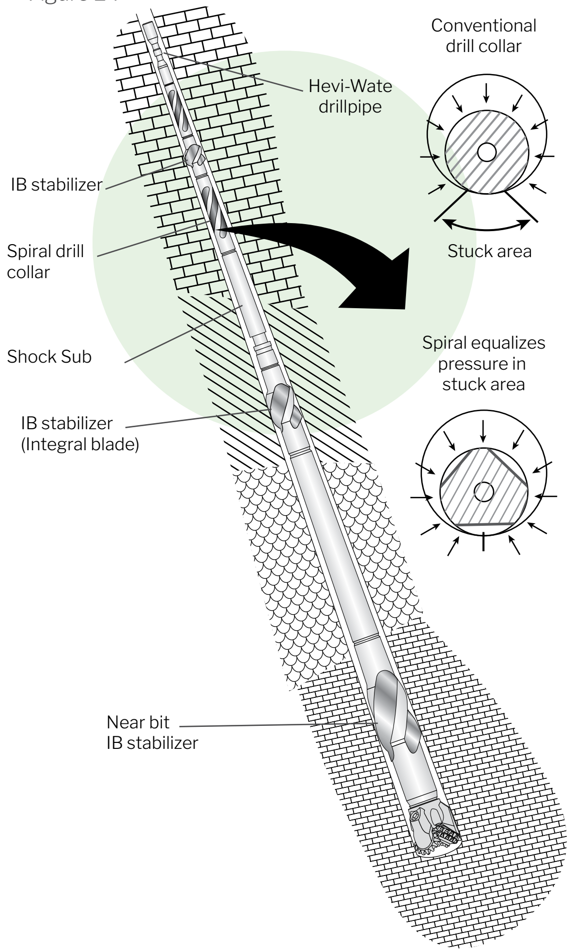
Spiral or Grooved Drill Collars

This tool presents a smaller contact area on the wall of the borehole. The spiral also allows fluid passage and equalization of wellbore pressure around the collars (Fig. 24). The box end of all sizes of spiral drill collars is left uncut for a distance of no less than 18-in. (457 mm) and no more than 24-in. (610 mm) below the shoulder. The pin end of all sizes of drill collars is left uncut for a distance of no less than 12-in. (305 mm) and no more than 22-in. (559 mm) above the shoulder. The uncut portions of the spiral drill collars facilitate the use of tongs for makeup and space to recut damaged threads.

Stabilizers

Stabilizers positioned throughout the drillstring (Fig. 24) are another positive way of preventing differential sticking. Rotating blade, welded blade and non-rotating sleeve-type stabilizers are used to keep the drill collars centered in the hole. Selection of the type of stabilizers and their spacing in the drillstring varies with the formation being drilled, the size of the borehole, etc. Contact a DRILCO representative to provide field data for your area.

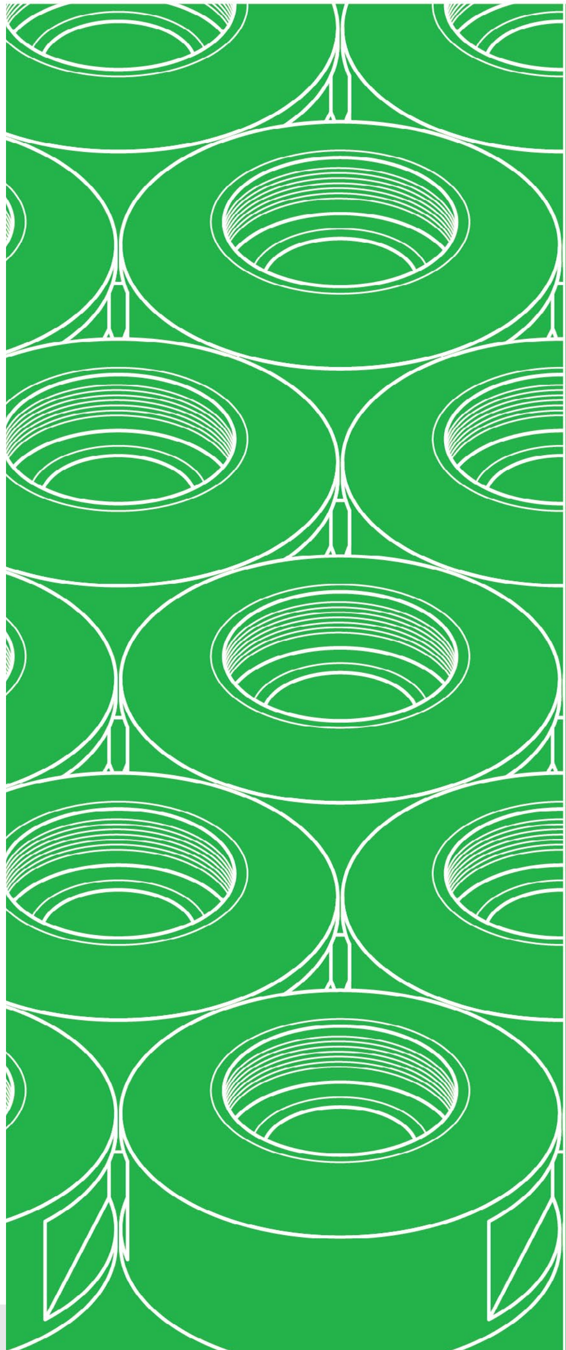
Figure 24



SECTION THREE

BIT STABILIZATION

3



BIT STABILIZATION

BIT STABILIZATION

Bit Stabilization Pays Off

About 55 years ago, bit engineers wondered why 7⅞-in. (200.0 mm) bits performed better than 8¾-in. (222.0-mm) bits. Then they realized both sizes of bits were run with 6¼-in. (158.0-mm) drill collars. The 7⅞-in. (200.0-mm) bits were clearly better stabilized than the 8¾-in. (222.3-mm) bits.

Since that time the art of bit stabilization has continued to improve. Over 50 years ago a case developed where a certain section in offset wells required 2,000 hours to drill in one area, and only 1,200 hours in the other. All of the normally recorded conditions on the bit records were the same. Then it was realized that small limber drill collars were used in the first area and a well-stabilized BHA in the other.

More recently drillers have been employing BHAs described on pages 12 through 20 to get optimum bit performance. The better the bit is stabilized, the better it performs and the longer it drills.

Large size bits have been notoriously neglected when applying stabilization techniques. It has been common practice to drill with 17½-in. (444.5-mm) bits with unstabilized 8-in. (203.2-mm) drill collars, this approximates trying to drill a 7⅞-in. (200.2-mm) hole with conventional 3⅞-in. (98.4-mm) drill collars.

Many years ago, when only very soft formations were drilled with such large bits, no severe problems were encountered. Now, drilling companies are trying to cope with drilling hard formations in these hole sizes. It has become apparent that the principles developed for smaller boreholes should also be extended to larger boreholes.

DRILCO recommends employing stiff, stabilizing assemblies described in this book with every bit used and every hole drilled. Theses principles have been proven in hole sizes as large as 120 in. (3,048 mm).

Stabilization Improves Bit Performance

Rock bits are designed to rotate about the axis of the hole being drilled. Their service life is shortened when the axis is misaligned. This misalignment may be parallel or angular.

When the axis at the bottom of the hole shifts in a parallel manner, the bit runs off center (Fig. 25). Running off center causes the bit's cutting structure to wear pick-shaped. This wear results in rings of uncut hole bottom to be created and bit life is drastically reduced.

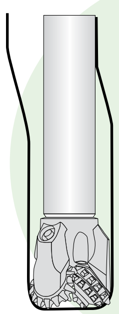
If the drill collar directly above the bit leans against the hole wall, angular misalignment occurs. The degradation of bit performance depends on the degree of misalignment. As an example, in an 8¾-in. (222.3-mm) hole, 7-in. (177.8-mm) collars reduce the effect to some degree, but misalignment still exists.

Angular misalignment permits two very harmful conditions to exist. First, the full weight on the bit is shifted from one cone to the other, causing rapid breakdown of tooth structure and bearings. Weight should be evenly distributed on all three cones. The second harmful condition is the breakdown of the vital gauge cutting surfaces at the tops of the outer tooth rows. Apple-shape cones result and bit life suffers greatly (Fig. 27).

Dramatic improvements in bit life have been observed in shifting from non-stabilized to stabilized BHAs, particularly when diamond bits, PDC bits, journal bearing or sealed bearing bits are being run.

Properly selected stabilizing assemblies avoid both angular and parallel misalignment with. The higher the degree of stabilization, the greater the benefits.

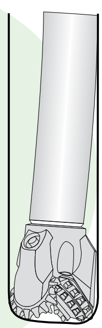
Figure 25



Parallel Misalignment

Parallel misalignment is caused by the use of small drill collars (in relation to the hole size) with no stabilization. The bit can move off center until the OD of the drill collar contacts the wall of the hole. This misalignment results in an offset from drilling off center.

Figure 26



Angular Misalignment

Angular misalignment can be caused by the use of small drill collars, in relation to the hole size, with no stabilization. Most or all of the bit load is applied to one cone at a time causing rapid breakdown and failure of both the bit cutting structure and cone bearings in the bit.

Figure 27

The bit in Figure 27 shows a broken medium, soft to medium formation roller cone bit that has been run off center. Note the cone shell, between rows of cutting structure, has been grooved by the rings of the uncut bottomhole formation.

Figure 28

Figure 28 shows a medium formation bit that has suffered gauge wear and gauge rounding due to angular misalignment.

Figure 29

The bit in Figure 29 has suffered severe damage to the gauge and OD of the bit itself. The lugs have worn so badly that the shirttails are gone and some of the roller bearings are missing. The bit was run too long in an abrasive formation. When the bit is pulled like this, the last portion of the hole was drilled undergauge and the entire tapered portion of the hole must be reamed to the proper bit gauge.

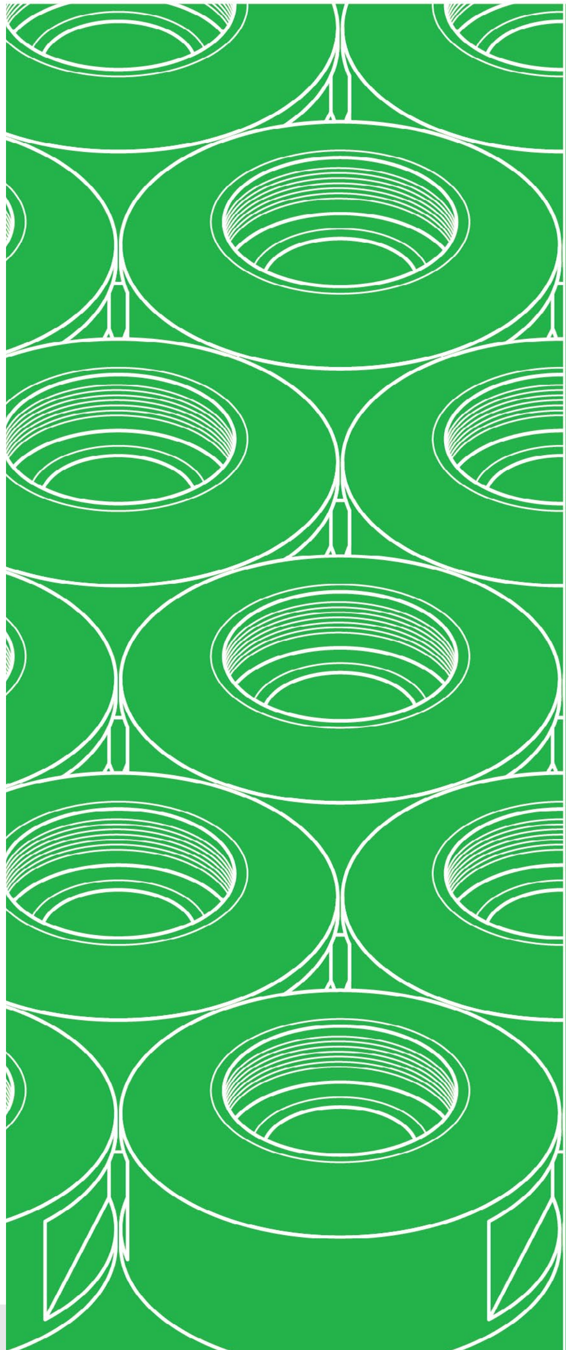
Figure 30

Figure 30 shows a broken medium, soft to medium bit that has been run without the support of a dampening device. A vibration dampener run in the BHA will help obtain faster rate of penetration and result in increased bit life. When drilling in broken hard formations, excessive vibration, bit bounce and shock loading can cause tooth and tungsten carbide insert breakage and rapid bearing failure. Rough-running in some formations, can result in not being able to utilize the desired weight on bit and rotating speed. The use of a vibration dampener will eliminate the damaging shock loading and help maintain a faster rate of penetration and longer bit life.

SECTION FOUR

DRILL COLLARS

4



DRILL COLLARS

DRILL COLLARS

DRILL COLLARS

Drill Collar Care and Maintenance

Avoid Ruining New Drill Collars

The following statement quoted from a series of articles published in the Pennwell Oil & Gas Journal® may lessen many drilling problems if these recommendations are followed by the rig crew.

"A new string of drill collars should give many months of trouble-free service, but they can be ruined on the first trip down the hole if they aren't properly cleaned and lubricated, and made up with measured and controlled makeup torque. In fact, the threads or shoulders can be damaged in picking up or on initial makeup, and be ruined before they are ever run into the hole."

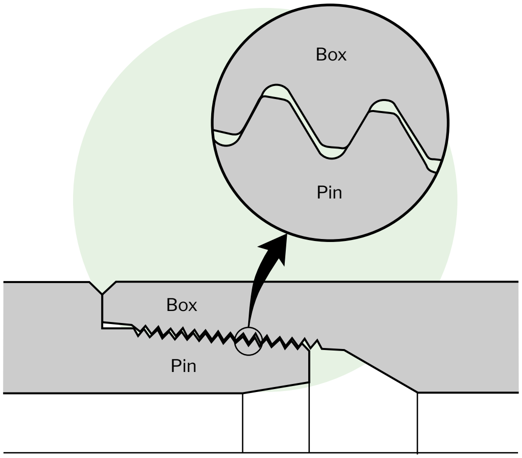
"Proper makeup torque, consistently measured and applied, is essential to satisfactory drill collar joint performance. Nothing that is done in design and manufacture can obviate the necessity for rig-level makeup torque control. It has to be done on the rig!"

Importance of Balanced Drill Collar Pin and Box Connections

Drill collar manufacturers recommend connection sizes based on the balance of pin and box bending strength ratios. The formula for this calculation is found in the API RP 7G.

The drill collar connection, more correctly called a rotary shouldered connection, must perform several necessary functions. The connection is a tapered thread jack screw that forces the shoulders together to form the only seal, and acts as a structural member to make the pin equally strong as the box in bending when the joint is made up to the API recommended torque. These threads do not form a seal unlike API production tubing tapered threads. By design, there is an open channel from the bore to the shoulder seal. This space is provided to accommodate excess thread compound, foreign matter and thread wear (Fig. 31).

Figure 31



See the guides and tips for proper selection of connections for various ODs and IDs on pages 78 through 95.

Recommended Drill Collar Care and Maintenance

Four important points that must be followed for proper drill collar performance are:

1. Properly lubricate shoulders and threads with appropriate tool joint compound.
2. Use proper tool joint torque.
3. Torque must be accurately measured.
4. Immediately repair minor damage.

Picking Up Drill Collars

1. Cast-steel thread protectors, with a lifting bail, provide a means of dragging the collar into the V door and protecting the shoulders and threads. Remember that the pin must also be protected during this operation.
2. Connections should be cleaned thoroughly with a solvent and wiped dry with a clean rag and inspected carefully for any burrs or marks on the shoulders.
3. The grade of drill collar tool joint compound is that recommended by API (American Petroleum Institute) RP 7A1, "Recommended Practice for Testing of Thread Compound for Rotary Shouldered Connections". This compound should be applied to the threads and shoulders on both pin and box. Drillpipe lubricants without a minimum of 40 to 50 percent zinc are not recommended by API if they are made with lead oxide. Lead oxide thread compounds were largely abandoned in the 1980s but may still exist in some locations. Lead oxide does not have sufficient body for the high shoulder loads necessary in drill collar makeup. This compound has the friction coefficient that was used to determine the API minimum recommended tool joint torque values. If any other lubricant is used correction factors for the friction coefficient must be applied to the API recommended torque values to assure the minimum recommended torque is used to makeup tool joints. If joint types other that API tool joints are used follow the manufacturer's recommendations for the proper tool joint compound and torque values.
4. Lift sub pins should be cleaned, inspected and lubricated on each trip. If the lift sub pins have been damaged and go unnoticed, they will eventually damage all of the drill collar boxes.

Initial Makeup of New Drill Collars

1. A new joint should be carefully lubricated. Any metal-to-metal contact may cause a thread gall. Application should be generous on shoulders, threads and in the pin relief grooves.
2. A good rig practice is to walk in the drill collar joint using chain tongs.
3. Makeup the tool joints to the minimum recommended torque.
4. Break out connection, inspect for damage and repair minor damage.
5. Re lubricate and makeup to the recommended torque.

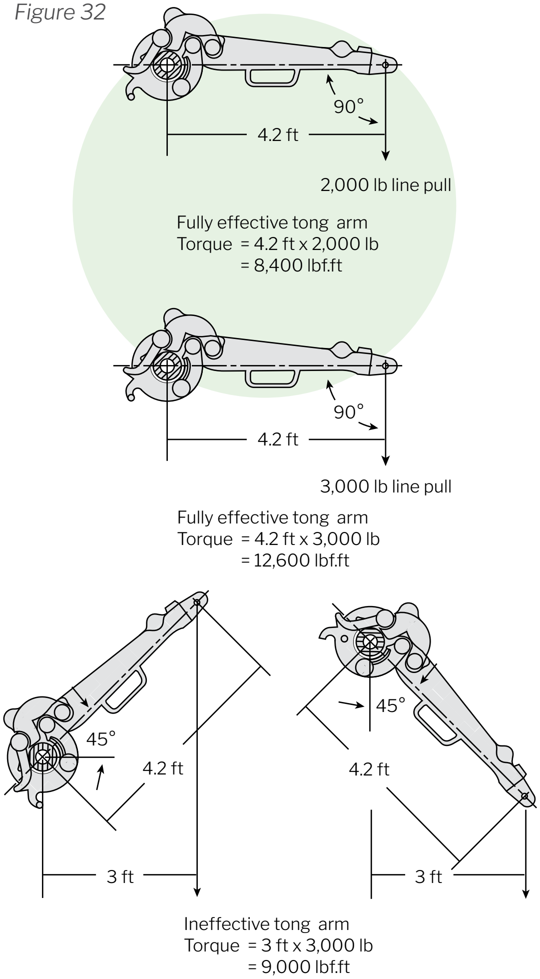
Torque Control

1. Torque is the measure of the amount of twisting force applied to drill collar tool joints as they are screwed together. The length of the tong arm in feet or meters multiplied by the line pull in pounds or newtons and is pound feet (lbf.ft) or newton meters (N.m) of torque. Use feet and tenths of a foot or meters and centimeters.

   The length of the tong arm in meters multiplied by the line pull in newtons is newton-meters (N.m) of torque.
2. A 4.2-ft tong arm and 2,000 lbf of line pull at the end of the tong, will produce 4.2 ft times 2,000 lbf, or a total of 8,400 lbf.ft of torque (see Fig. 32).

A 1.28-m tong arm and 907 newtons of line pull at the end of the tong, will produce a 1.28 m times 907 N or a total of 1,161 N.m of torque (Fig. 32).

Figure 32



3. A line pull measuring device must be used in making up drill collars. It is important that line pull be measured when the line is at right angles (90 degrees) to the tong handle.

4. When applying line pull to the tongs, it is better to apply a long steady pull rather than to jerk the line. Hold the pull momentarily to make sure all line slack is taken up.

5. The proper torque required for a specific drill collar should be taken from a table of recommended torques for drill collars. For a 6½-in. (165.1 mm) OD x 2$^{13}/_{16}$-in. (71.4 mm) ID with a NC 50 connection, the table indicates a torque of 29,679 lbf.ft (43,657 N.m) (see pages 54 through 65).

Recommended Minimum Torque, lbf.ft [N.m]

Connection Type	OD, in. [mm]	Bore of Drill Collars, (in. [mm])				
		2¼ [57.1]	**2½ [63.5]**	**2$^{13}/_{16}$ [71.4]**	**3 [76.2]**	**3¼ [82.5]**
NC 50	6½ [165.1]	29,679 [43,657]	29,679 [43,657]	29,679 [43,657]	29,966 [43,657]	26,675 [43,657]

6. It should be emphasized that the torque values shown in the table are minimum requirements. The normal torque range is from the tabulated figure to 10% higher.

   From the example above, the required torque is 29,679 lbf.ft; thus [29,679 lbf.ft (1.10) = 32,647 lbf.ft

Rig Maintenance of Drill Collars

1. The DRILCO recommended practice is to break a different joint on each trip, giving the crew an opportunity to inspect each pin and box every third trip. Inspect the shoulders for signs of loose connections, thread galling and possible washouts.

2. Thread protectors must be used on both pin and box when picking up or laying down the drill collars.

3. Periodically, based on drilling conditions and experience, a magnetic particle inspection method using a wet system and black light should be performed.

4. Before storing the drill collars, they should be cleaned. If necessary, reface the shoulders with a shoulder refacing tool, and remove the fins on the shoulders by beveling. A good rust preventative or drill collar compound should be liberally applied to the connections, and thread protectors installed.

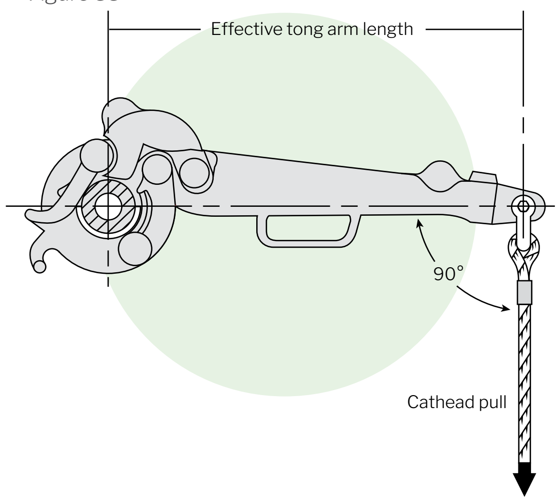
Method of Determining the Drill Collar Makeup Torque Required

The recommended process of drill collar makeup as discussed on pages 38 through 41, must be used and this torque must be measured with an accurate device.

There are two steps that should be used for all hookups:

1. Consult the torque tables on pages 54 to 65 to find the minimum torque recommended for the size drill collars (OD and ID) and connection type.
2. Divide the torque value by the effective length of the tong arm (Fig. 33). The value determined will be total line pull required from the cathead.

Figure 33



Example:
For 42-in. tongs, divide by 12 in. = 3.5 ft

For 48-in. tongs, divide by 12 in. = 4 ft

For 50-in. tongs, divide by 12 in. = 4.2 ft

For 54-in. tongs, divide by 12 in. = 4.5 ft

For collars with $6\frac{1}{2}$-in. OD x $2\frac{13}{16}$-in. ID and NC 50 ($4\frac{1}{2}$ IF) connections, the tables recommend 29,679 lbf.ft of makeup torque. If the effective tong arm length is 50 in then:

$$\frac{50 \text{ in.}}{12 \text{ in.}} = 4.2 \text{ ft}$$

$$\frac{29{,}679 \text{ lbf.ft}}{4.2 \text{ ft}} = 7{,}066 \text{ lbf of line pull}$$

Example:
For 42-in. tongs, multiply by .0254 = 1.07 m

For 48-in. tongs, multiply by .0254 = 1.22 m

For 50-in. tongs, multiply by .0254 = 1.27 m

For 54-in. tongs, multiply by .0254 = 1.37 m

For collars with 157.1-mm OD x 71.4-mm ID and NC 50 ($4\frac{1}{2}$ IF) connections, the tables recommend 40,237 N.m of makeup torque. If the effective tong arm length is 50 in. then:

(50 in.) x (.0254) = 1.27 m

$$\frac{40{,}237 \text{ N.m}}{1.27 \text{ m}} = 31{,}683 \text{ N of line pull}$$

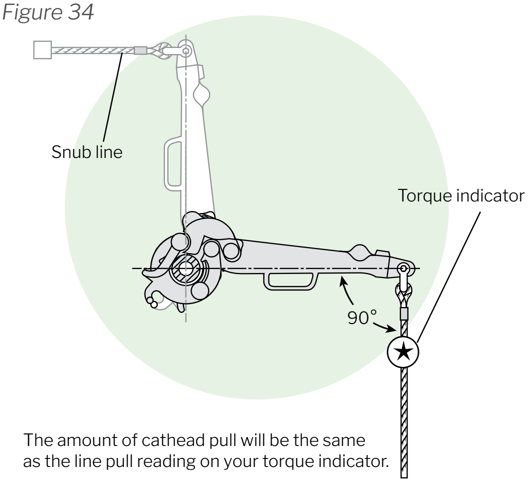
7,066 lbf [31,683 N] of line pull is the total pull required on the end of a 4.2 ft [1.27 m] tong. The resultant may or may not be the amount of line pull reading on the torque indicator, since this depends on the location of the indicator.

The following pages provide 15 examples of tong arrangement used to makeup drill collar connections. To determine the amount of pull required for a given situation select the arrangement being used and follow the steps outlined.

Note: The heavy black arrow in the examples shown on the following pages, is used to indicate cathead pull.

Caution: *Before torquing, make sure the tongs are of sufficient strength.*

Figure 34



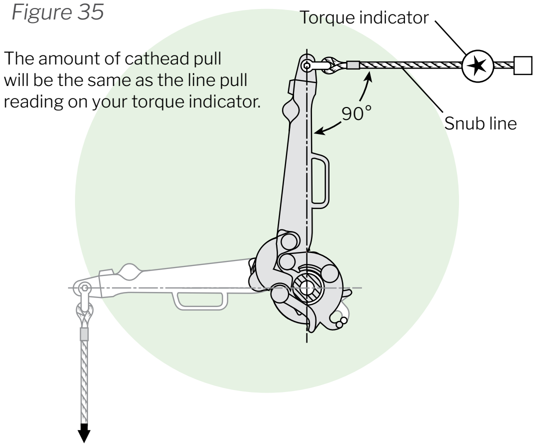
To determine the amount of pull required:

1. Look up the minimum recommended torque required in the torque tables, pages 54-65.

2. Divide the torque value by the effective tong length.

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 35

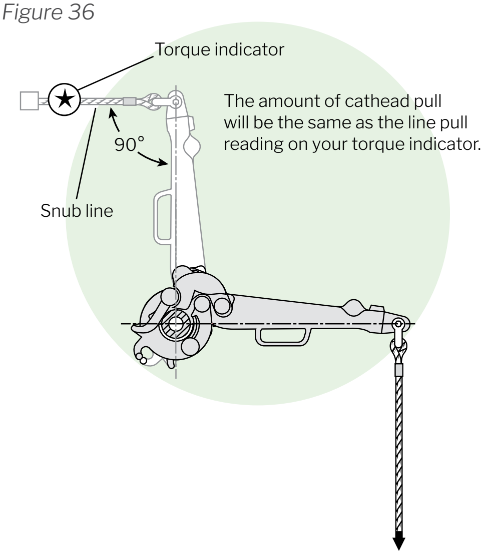


To determine the amount of pull required:

1. *Look up the minimum recommended torque required in the torque tables, pages 54-65.*
2. *Divide the torque value by the effective tong length.*

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 36

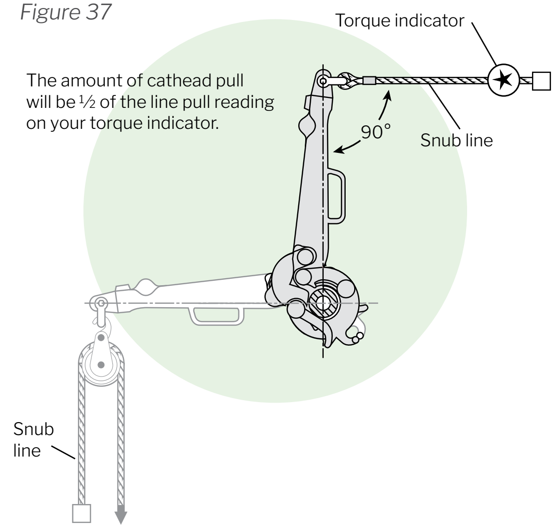


To determine the amount of pull required:

1. *Look up the minimum recommended torque required in the torque tables, pages 54-65.*
2. *Divide the torque value by the effective tong length.*

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 37

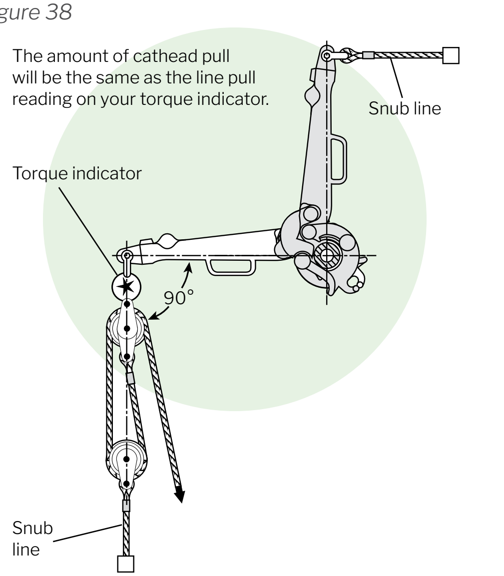


To determine the amount of pull required:

1. *Look up the minimum recommended torque required in the torque tables, pages 54-65.*
2. *Divide the torque value by the effective tong length.*

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 38

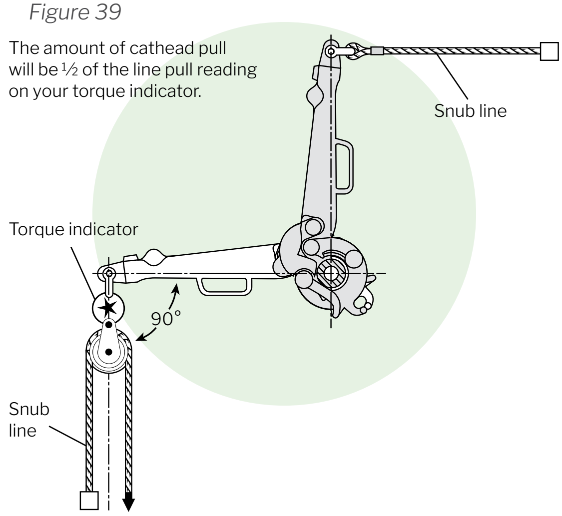


To determine the amount of pull required:

1. *Look up the minimum recommended torque required in the torque tables, pages 54-65.*
2. *Divide the torque value by the effective tong length.*

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 39

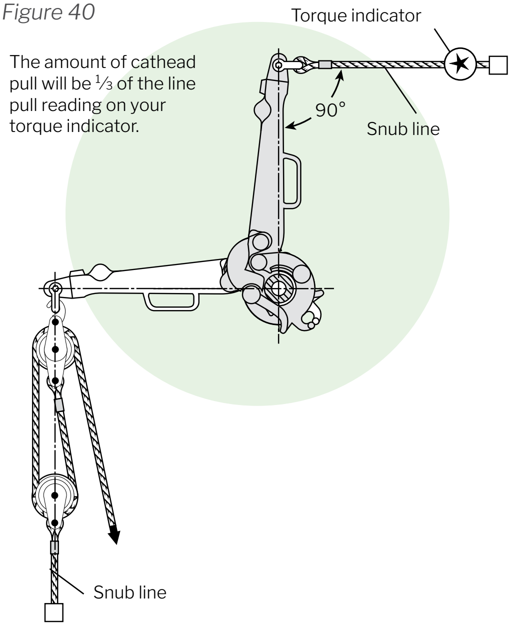


To determine the amount of pull required:

1. *Look up the minimum recommended torque required in the torque tables, pages 54-65.*
2. *Divide the torque value by the effective tong length.*

The result is pounds or newtons pull for the line pull indicator when in this position.

Figure 40



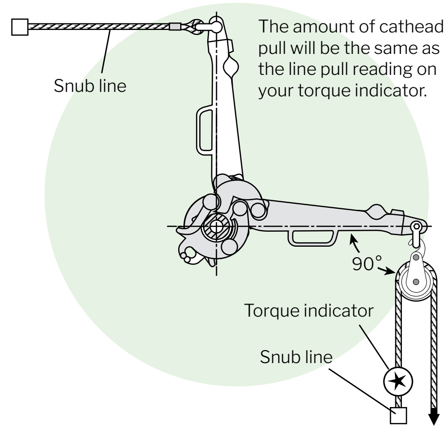
To determine the amount of pull required:

1. *Look up the minimum recommended torque required in the torque tables, pages 54-65.*
2. *Divide the torque value by the effective tong length.*

The result is pounds or Newtons pull for the line pull indicator when in this position.

DRILL COLLARS

Figure 41

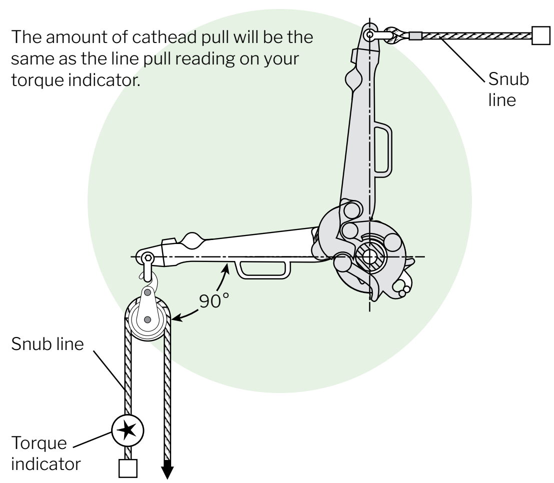


To determine the amount of pull required:

1. *Look up the minimum recommended torque required in the torque tables, pages 54-65.*
2. *Divide the torque value by the effective tong length.*
3. *Divide the result by 2*

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 42

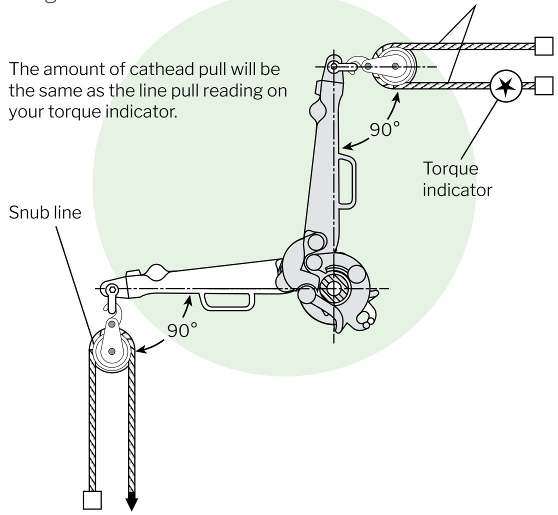


To determine the amount of pull required:

1. *Look up the minimum recommended torque required in the torque tables, pages 54-65.*
2. *Divide the torque value by the effective tong length.*
3. *Divide the result by 2.*

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 43



To determine the amount of pull required:

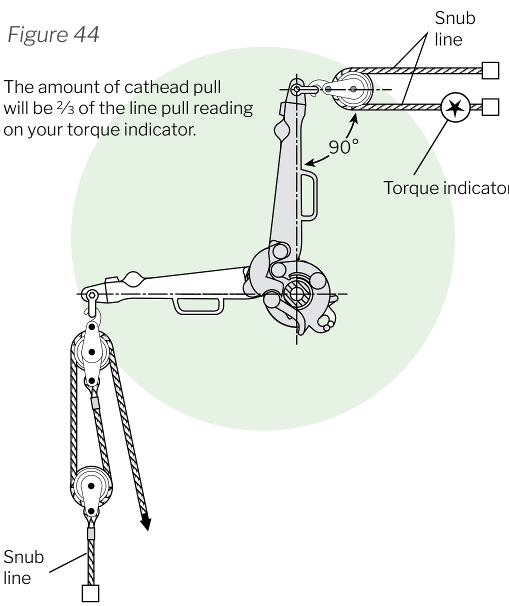
1. Look up the minimum recommended torque required in the torque tables, pages 54-65.

2. Divide the torque value by the effective tong length.

3. Divide the result by 2.

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 44



To determine the amount of pull required:

1. Look up the minimum recommended torque required in the torque tables, pages 54-65.

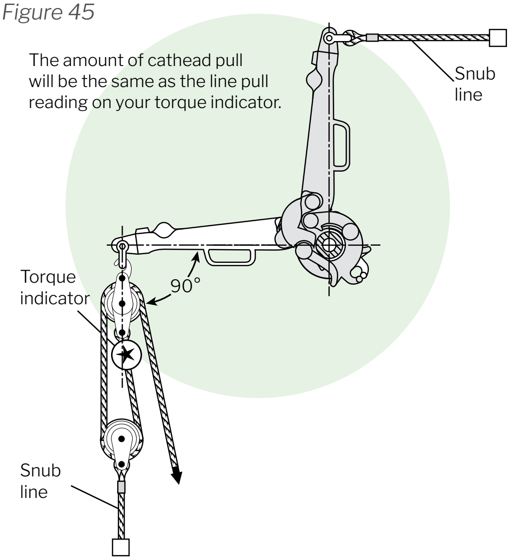
2. Divide the torque value by the effective tong length.

3. Divide the result by 2.

The result is pounds or Newtons pull for the line pull indicator when in this position.

DRILL COLLARS

Figure 45



To determine the amount of pull required:

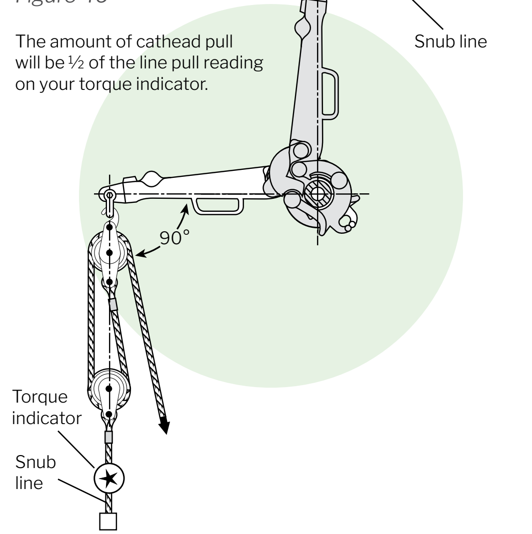
1. Look up the minimum recommended torque required in the torque tables, pages 54-65.

2. Divide the torque value by the effective tong length.

3. Divide the result by 3.

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 46



To determine the amount of pull required:

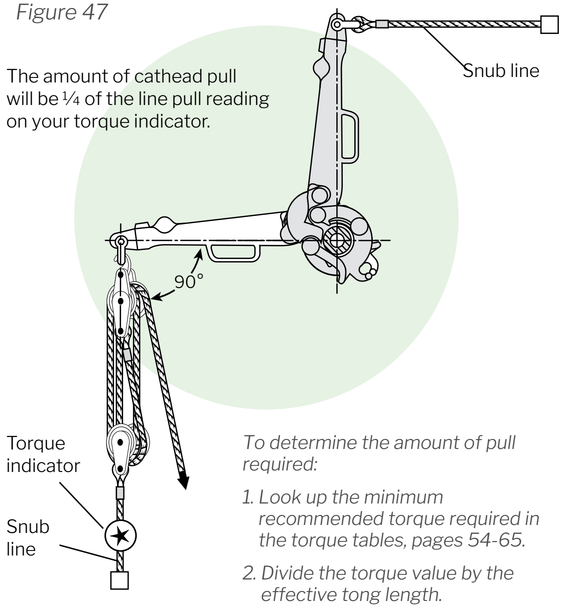
1. Look up the minimum recommended torque required in the torque tables, pages 54-65.

2. Divide the torque value by the effective tong length.

3. Divide by 3 then multiply by 2.

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 47



To determine the amount of pull required:

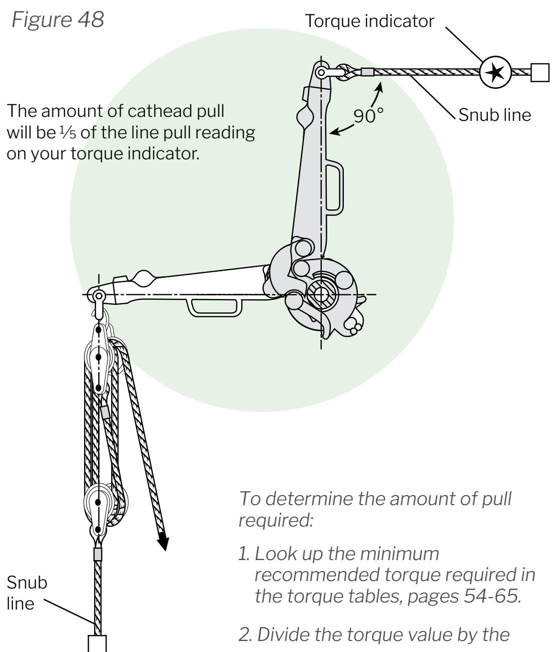
1. Look up the minimum recommended torque required in the torque tables, pages 54-65.

2. Divide the torque value by the effective tong length.

3. Divide this by 5, and multiply by 4. This will be the pounds pull reading for the line pull indicator when in this position.

The result is pounds or Newtons pull for the line pull indicator when in this position.

Figure 48



To determine the amount of pull required:

1. Look up the minimum recommended torque required in the torque tables, pages 54-65.

2. Divide the torque value by the effective tong length.

The result is pounds or Newtons pull for the line pull indicator when in this position.

Applying and Measuring Makeup Torque

Rig Catheads

Most drilling rigs have a cathead on each side of the drawworks. A cathead is used to apply line pull to the tongs. The cathead does not have a built in device to measure the amount of line pull. A line pull measuring device must be added to the line between the tongs and the cathead to accomplish this task. The driller is required to release the cathead clutch at the appropriate time in order to ensure the desired pull is not exceeded. This often causes errors in application of the torque.

Hydraulic Load Cells

For measuring the amount of applied line pull, many rigs use a hydraulic load cell. A load cell is a simple device that is generally very reliable. A load cell usually consists of three parts: (1) a small hydraulic cylinder, (2) a pressure gauge that reads the amount of pull, and (3) a rubber hose to connect the cylinder and the gauge. One must remember that the gauge reads in units of force and not in units of torque. You must measure the length of the tongs and multiply the gauge reading by the tong length to get units of torque. In the US this will usually be in pounds-force and other areas of the world probably in Newtons.

Automatic Torque Control System

DRILCO provides a system that eliminates the problems associated with using the rig's catheads, the ATCS* automatic torque control system. The ATCS system is a highly accurate solid-state electronic control that automatically terminates makeup of the drillstring connection when the specific amount of torque is reached. The ATCS system can be used on any rig that has manual tongs and air-activated cathead clutch. With a few modifications the system can be adapted to a hydraulic makeup system.

The ATCS system includes an intrinsically safe load cell, explosion-proof air controllers and an air-purged control panel for operation in Class 1, Group D, Divisions 1 and 2 hazardous environments. For operation in all Division 1 situations, a power time delay unit is required.

What the ATCS system provides

- Safety—The driller is freed from watching hydraulic torque gauges for the makeup of each connection, allowing focus on the rig floor activities.
- Reduced trip time—Automatic application of makeup torque results in faster and optimum rig floor rhythm of movement.
- Reduced pin and box damage—Improper torque is the primary cause of swelled boxes, stretched pins, and galled threads and shoulders.
- Minimized risk of fishing jobs—Improper makeup torque causes washouts and twistoffs.
- Reduced rig downtime—By eliminating torque-related failures, you can avoid the expense of laying down damaged pipe and tools, repair or replacement, and loss of costly rig time.

Hydraulic Line Pull Devices

Sometimes drilling rigs do not have catheads or have catheads with insufficient capacity or simply do not want to use them for the makeup of large rotary shouldered connections. In these cases, the rig must rely on external devices to supply the line pull to the tongs. These devices take the form of hydraulic cylinders and power sources.

Ezy-Torq Hydraulic Cathead

In the 1960s DRILCO developed the Ezy-Torq* hydraulic cathead for use on large connections that were beyond the capacity of most rig air powered catheads. Its primary function is to provide a line pull source for connections that require torques ranging from 40,000 to 150,000 lbf.ft. When you use the hydraulic cathead on connections requiring less than 40,000 lbf.ft, you should always calibrate the unit with a load cell.

The Ezy-Torq hydraulic cathead is available in two different configurations:

1. One which has its own self-contained power source.
2. One which uses an auxiliary power source supplied by the user.

For either source of power, the hydraulic cylinder and cylinder installation/arrangement are the same.

Note: Each torque measuring device has a limit for the total amount of line pull it can accurately measure. Know the limit of the instrument you are using and work within the recommended range (see pages 40 through 50).

Multiple line hookups can provide many times the normal makeup line pull. Great care should be taken to see that the lines do not become crossed, twisted or fouled. When it comes time for the maximum pull on the rig floor, be sure everyone is clear of the immediate area around the tongs.

Caution: *Know the rating of the tongs before maximum pull is attempted.*

The slack in the tong safety line should be sufficient for the tongs to obtain full benefit of the pull from the cathead, but short enough to prevent complete rotation of the tongs.

DRILL COLLARS

Recommended Minimum Makeup Torque, lbf.ft [See Note 2]

Recommended Minimum Makeup Torque, lbf.ft [See Note 2]

Size and Type of Connection, in.	OD, in.	Bore of Drill Collars, in.											
		1	1¼	1½	1¾	2	2¼	2½	2 13/16	3	3¼	3½	3¾
	3	2,508†	2,508†	2,508†									
API NC 23	3⅛	3,330†	3,330†	2,647									
	3¼	4,000	3,387	2,647									
	3		2,241†	2,241†	1,749								
2⅜ Reg	3⅛		3,028†	2,574	1,749								
	3¼		3,285	2,574	1,749								
	3		3,797†	3,797†	2,926								
2⅞ PAC	3⅛		4,966†	4,151	2,926								
	3¼		5,206	4,151	2,926								
2⅜ IF	3⅜		3,581†	3,581†	3,581†								
API NC 26	3½		4,606†	4,606†	3,697								
2⅞ SH	3¾		5,501	4,668	3,697								
	3½		3,838†	3,838†	3,838†								
2⅞ Reg	3¾		5,766	4,951	4,002								
	3⅞		5,766	4,951	4,002								
2⅞ XH	3¾		4,089†	4,089†	4,089†								
3½ DSL	3⅞		5,352†	5,352†	5,352†								
2⅞ Mod. Open	4⅛		8,059†	8,059†	7,433								
2⅞ IF	3⅞		4,640†	4,640†	4,640†	4,640†	4,640†						
API NC 31	4⅛		7,390†	7,390†	7,390†	6,853	5,391						
3½ SH	4¼		8,858†	8,858†	8,161	6,853	5,391						
	4½		10,286	9,307	8,161	6,853	5,391						
	4⅛		6,466†	6,466†	6,466†	6,466†	5,685						
3½ Reg	4¼		7,886†	7,886†	7,886†	7,115	5,685						
	4½		10,471†	9,514	8,394	7,115	5,685						
	4½				9,038†	9,038†	9,038†	7,411					
API NC 35	4¾				12,273	10,826	9,202	7,411					
	5				12,273	10,826	9,202	7,411					
3½ XH	4¼				5,161†	5,161†	5,161†	5,161†					
4 SH	4½				8,479†	8,479†	8,479†	8,311					
3½ Mod. Open	4¾				12,074†	11,803	10,144	8,311					
	5				13,283	11,803	10,144	8,311					
	5¼				13,283	11,803	10,144	8,311					
	4¾				9,986†	9,986†	9,986†	9,986†	8,315				
3½ IF	5				13,949†	13,949†	12,907	10,977	8,315				
API NC 38	5¼				16,207	14,643	12,907	10,977	8,315				
4½ SH	5½				16,207	14,643	12,907	10,977	8,315				
	4¾				8,784†	8,784†	8,784†	8,784†	8,784†				
3½ H-90	5				12,792†	12,792†	12,792†	12,792†	10,390				
	5¼				17,091†	16,910	15,118	13,133	10,390				
	5½				18,502	16,910	15,118	13,133	10,390				
	5				10,910†	10,910†	10,910†	10,910†	10,910†				
4 FH	5¼				15,290†	15,290†	15,290†	14,969	12,125				
API NC 40	5½				19,985†	18,886	17,028	14,969	12,125				
4 Mod. Open	5¾				20,539	18,886	17,028	14,969	12,125				
4½ DSL	6				20,539	18,886	17,028	14,969	12,125				
	5¼				12,590†	12,590†	12,590†	12,590†	12,590†				
	5½				17,401†	17,401†	17,401†	17,401†	16,536				
4 H-90	5¾				22,531†	22,531†	21,714	19,543	16,536				
	6				25,408	23,671	21,714	19,543	16,536				
	6¼				25,408	23,671	21,714	19,543	16,536				
	5½				15,576†	15,576†	15,576†	15,576†	15,576†				
4½ Reg	5¾				20,609†	20,609†	20,609†	19,601	16,629				
	6				25,407	23,686	21,749	19,601	16,629				
	6¼				25,407	23,686	21,749	19,601	16,629				
	5¾				20,895†	20,895†	20,895†	20,895†	18,161				
API NC 44	6				26,453†	25,510	23,493	21,257	18,161				
	6¼				27,300	25,510	23,493	21,257	18,161				
	6½				27,300	25,510	23,493	21,257	18,161				
	5½					12,973†	12,973†	12,973†	12,973†	12,973†			
	5¾					18,119†	18,119†	18,119†	18,119†	17,900			
4½ FH	6					23,605†	23,605†	23,028	19,921	17,900			
	6¼					27,294	25,272	23,028	19,921	17,900			
	6½					27,294	25,272	23,028	19,921	17,900			
4½ XH	5¾						17,738†	17,738†	17,738†	17,738†			
API NC 46	6						23,422†	23,422†	22,426	20,311			
4 IF	6¼						28,021	25,676	22,426	20,311			
5 DSL	6½						28,021	25,676	22,426	20,311			
4½ Mod. Open	6¾						28,021	25,676	22,426	20,311			
	5¾						18,019†	18,019†	18,019†	18,019†			
	6						23,681†	23,681†	23,159	21,051			
4½ H-90	6¼						28,732	26,397	23,159	21,051			
	6½						28,732	26,397	23,159	21,051			
	6¾						28,732	26,397	23,159	21,051			
	6¼						25,360†	25,360†	25,360†	25,360†	23,988		
5 H-90	6½						31,895†	31,895†	29,400	27,167	23,988		
	6¾						35,292	32,825	29,400	27,167	23,988		
	7						35,292	32,825	29,400	27,167	23,988		
	6¾						34,508†	34,508†	34,508†	34,142	30,781		
5½ H-90	7						41,993†	40,117	36,501	34,142	30,781		
	7¼						42,719	40,117	36,501	34,142	30,781		
	7½						42,719	40,117	36,501	34,142	30,781		
	6¾						31,941†	31,941†	31,941†	31,941†	30,495		
5½ Reg	7						39,419†	39,419†	36,235	33,868	30,495		
	7¼						42,481	39,866	36,235	33,868	30,495		
	7½						42,481	39,866	36,235	33,868	30,495		
4½ IF	6¼						23,004†	23,004†	23,004†	23,004†	23,004†		
API NC 50	6½						29,679†	29,679†	29,679†	29,966†	26,675		
5 XH	6¾						36,742†	35,824	32,277	29,966	26,675		
5 Mod. Open	7						38,379	35,824	32,277	29,966	26,675		
5½ DSL	7¼						38,379	35,824	32,277	29,966	26,675		
5 Semi-IF	7½						38,379	35,824	32,277	29,966	26,675		

1. Basis of calculations for recommended makeup torque assumes the use of an API recommended thread compound containing 40 to 60% by weight of finely powdered metallic zinc with not more than 0.3% total active sulfur, applied thoroughly to all threads and shoulders. Also using the modified screw jack formula as shown in the IADC Drilling Manual and the API Recommended Practice RP 7G. For API connections and their interchangeable connections, makeup torque is based on 62,500 psi stress in the pin or box, whichever is weaker.

DRILL COLLARS

Recommended Minimum Makeup Torque, lbf.ft [See Note 2]

Size and Type of Connection, in.	OD, in.	Bore of Drill Collars, in. 1	1¼	1½	1¾	2	2¼	2½	2 13/16	3	3¼	3½	3¾
5½ FH	7						32,762†	32,762†	32,762†	32,762†	32,762†		
	7¼						40,998†	40,998†	40,998†	40,998†	40,998†		
	7½						49,661†	49,661†	47,756	45,190	41,533		
	7¾						54,515	51,687	47,756	45,190	41,533		
API NC 56	7¼							40,498†	40,498†	40,498†	40,498†		
	7½							49,060†	48,221	45,680	42,058		
	7¾							52,115	48,221	45,680	42,058		
	8							52,115	48,221	45,680	42,058		
6⅝ Reg	7½							46,399†	46,399†	46,399†	46,399†		
	7¾							55,627†	53,346	50,704	46,935		
	8							57,393	53,346	50,704	46,935		
	8¼							57,393	53,346	50,704	46,935		
6⅝ H-90	7½							46,509†	46,509†	46,509†	46,509†		
	7¾							55,708†	55,708†	53,629	49,855		
	8							60,321	56,273	53,629	49,855		
	8¼							60,321	56,273	53,629	49,855		
API NC 61	8							55,131†	55,131†	55,131†	55,131†		
	8¼							65,438†	65,438†	65,438†	61,624		
	8½							72,670	68,398	65,607	61,624		
	8¾							72,670	68,398	65,607	61,624		
	9							72,670	68,398	65,607	61,624		
5½ IF	8							56,641†	56,641†	56,641†	56,641†	56,641†	
	8¼							67,133†	67,133†	67,133†	63,381	59,027	
	8½							74,626	70,227	67,436	63,381	59,027	
	8¾							74,626	70,227	67,436	63,381	59,027	
	9							74,626	70,227	67,436	63,381	59,027	
	9¼							74,626	70,227	67,436	63,381	59,027	
6⅝ FH	8½							67,789†	67,789†	67,789†	67,789†	67,789†	67,184
	8¾							79,544†	79,544†	79,544†	76,706	72,102	67,184
	9							88,582	83,992	80,991	76,706	72,102	67,184
	9¼							88,582	83,992	80,991	76,706	72,102	67,184
	9½							88,582	83,992	80,991	76,706	72,102	67,284
API NC 70	9							75,781†	75,781†	75,781†	75,781†	75,781†	75,781†
	9¼							88,802†	88,802†	88,802†	88,802†	88,802†	88,802†
	9½							102,354†	102,354†	102,354†	101,107	96,214	90,984
	9¾							113,710	108,841	105,657	101,107	96,214	90,984
	10							113,710	108,841	105,657	101,107	96,214	90,984
	10¼							113,710	108,841	105,657	101,107	96,214	90,984
API NC 77	10							108,194†	108,194†	108,194†	108,194†	108,194†	108,194†
	10¼							124,051†	124,051†	124,051†	124,051†	124,051†	124,051†
	10½							140,491†	140,491†	140,491†	140,488	135,119	129,375
	10¾							154,297	148,965	145,476	140,488	135,119	129,375
	11							154,297	148,965	145,476	140,488	135,119	129,375
Connections with full faces													
7 H-90	8‡							53,454†	53,454†	53,454†	53,454†	53,454†	53,454†
	8¼‡							63,738†	63,738†	63,738†	63,738†	60,971	56,382
	8½‡							74,478	72,066	69,265	65,267	60,971	56,382
7⅝ Reg	8½‡							60,402†	60,402†	60,402†	60,402†	60,402†	60,402†
	8¾‡							72,169†	72,169†	72,169†	72,169†	72,169†	72,169†
	9‡							84,442†	84,442†	84,442†	84,221	79,536	74,529
	9¼‡							96,301	91,633	88,580	84,221	79,536	74,529
	9½‡							96,301	91,633	88,580	84,221	79,536	74,529
7⅝ H-90	9‡							73,017†	73,017†	73,017†	73,017†	73,017†	73,017†
	9¼‡							86,006†	86,006†	86,006†	86,006†	86,006†	86,006†
	9½‡							99,508†	99,508†	99,508†	99,508†	99,508†	96,285
8⅝ Reg	10‡							109,345†	109,345†	109,345†	109,345†	109,345†	109,345†
	10¼‡							125,263†	125,263†	125,263†	125,263†	125,263†	125,034
	10½‡							141,767†	141,767†	141,134	136,146	130,777	125,034
8⅝ H-90	10¼‡							113,482†	113,482†	113,482†	113,482†	113,482†	113,482†
	10½‡							130,063†	130,063†	130,063†	130,063†	130,063†	130,063†
Connections with low torque faces													
7 H-90	8¾								68,061†	68,061†	67,257	62,845	58,131
	9								74,235	71,361	67,257	62,845	58,131
7⅝ Reg	9¼								73,099†	73,099†	73,099†	73,099†	73,099†
	9½								86,463†	86,463†	86,463†	82,457	77,289
	9¾								94,936	91,789	87,292	82,457	77,289
	10								94,936	91,789	87,292	82,457	77,289
7⅝ H-90	9¾								91,667†	91,667†	91,667†	91,667†	91,667†
	10								106,260†	106,260†	106,260†	104,171	98,804
	10¼								117,112	113,851	109,188	104,171	98,804
	10½								117,112	113,851	109,188	104,171	98,804
8⅝ Reg	10¾									112,883†	112,883†	112,883†	112,883†
	11									130,672†	130,672†	130,672†	130,672†
	11¼									147,616	142,430	136,846	130,871
8⅝ H-90	10¾									92,960†	92,960†	92,960†	92,960†
	11									110,781†	110,781†	110,781†	110,781†
	11¼									129,203†	129,203†	129,203†	129,203†

2. Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

3. H-90 connections makeup torque is based on 56,200 psi stress and other factors as stated in Note 1.

4. The 2⅞-in. PAC makeup torque is based on 87,500 psi stress and other factors as stated in Note 1.

‡5. Largest diameter shown is the maximum recommended for these full faced connections. If larger diameters are used, machine connections with low torque faces and use the torque values shown under low torque face tables. If low torque faces are not used, see Note 2 for increased torque values.

†6. Torque figures succeeded by a dagger (†) indicate that the weaker member for the corresponding OD and bore is the box. For all other torque values the weaker member is the pin.

DRILL COLLARS

Recommended Minimum Makeup Torque, kg.m [See Note 2]

Size and Type of Connection, in.	OD, mm	Bore of Drill Collars, mm											
		25.4	31.7	38.1	44.4	50.8	57.1	63.5	71.4	76.2	82.5	88.9	95.2
API NC 23	76.2	347†	347†	347†									
	79.4	460†	460†	366									
	82.6	553	468	366									
2⅜ Reg	76.2		310†	310†	242								
	79.4		419†	356	242								
	82.6		454	356	242								
2⅞ PAC	76.2		525†	525†	405								
	79.4		687†	574	405								
	82.6		720	574	405								
2⅜ IF													
API NC 26	88.9		637†	637†	511								
2⅞ SH	95.2		761	645	511								
2⅞ Reg	88.9		531†	531†	531†								
	95.2		797	685	553								
	98.4		797	685	553								
2⅞ XH	95.2		565†	565†	565†								
3½ DSL	98.4		740†	740†	740†								
2⅞ Mod. Open	104.8		1,114†	1,114†	1,028								
2⅞ IF	98.4		641†	641†	641†	641†							
API NC 31	104.8		1,022†	1,022†	1,022†	947							
3½ SH	107.9		1,225†	1,225†	1,128	947							
	114.3		1,422	1,287	1,128	947							
3½ Reg	104.8		894†	894†	894†	894†	786						
	107.9		1,090†	1,090†	1,090†	984	786						
	114.3		1,448	1,315	1,160	984	786						
API NC 35	114.3				1,250†	1,250†	1,250†	1,025†					
	120.6				1,697	1,497	1,272	1,025					
	127.0				1,697	1,497	1,272	1,025					
3½ XH	107.9				714†	714†	714†	714†					
4 SH	114.3				1,172†	1,172†	1,172†	1,149					
3½ Mod. Open	120.6				1,669†	1,632	1,402	1,149					
	127.0				1,836	1,632	1,402	1,149					
	133.3				1,836	1,632	1,402	1,149					
3½ IF	120.6				1,381†	1,381†	1,381†	1,381†	1,150				
API NC 38	127.0				1,929†	1,929†	1,785	1,518	1,150				
4½ SH	133.3				2,241	2,026	1,785	1,518	1,150				
	139.7				2,241	2,026	1,785	1,518	1,150				
3½ H-90	120.6				1,215†	1,215†	1,215†	1,215†	1,215†				
	127.0				1,769†	1,769†	1,769†	1,769†	1,439				
	133.3				2,363†	2,341	2,093	1,819	1,439				
	139.7				2,561	2,341	2,093	1,819	1,439				
4 FH	127.0				1,508†	1,508†	1,508†	1,508†	1,508†				
API NC 40	133.3				2,114†	2,114†	2,114†	2,070	1,676				
4 Mod. Open	139.7				2,763†	2,611	2,354	2,070	1,676				
4½ DSL	146.0				2,840	2,611	2,354	2,070	1,676				
	152.4				2,840	2,611	2,354	2,070	1,676				
4 H-90	133.3					1,741†	1,741†	1,741†	1,741†				
	139.7					2,406†	2,406†	2,406†	2,287				
	146.0					3,115†	3,003	2,702	2,287				
	152.4					3,273	3,003	2,702	2,287				
	168.7					3,273	3,003	2,702	2,287				
4½ Reg	139.7					2,153†	2,153†	2,153†	2,153†				
	146.0					2,849†	2,849†	2,710	2,299				
	152.4					3,275	3,007	2,710	2,299				
	158.7					3,275	3,007	2,710	2,299				
API NC 44	146.0					2,889†	2,889†	2,889†	2,511				
	152.4					3,527	3,248	2,939	2,511				
	158.7					3,527	3,248	2,939	2,511				
	165.1					3,527	3,248	2,939	2,511				
4½ FH	139.7					1,794†	1,794†	1,794†	1,794†	1,794†			
	146.0					2,505†	2,505†	2,505†	2,505†	2,475			
	152.4					3,264†	3,264†	3,184	2,754	2,475			
	158.7					3,774	3,494	3,184	2,754	2,475			
	165.1					3,774	3,494	3,184	2,754	2,475			
4½ XH	146.0						2,452†	2,452†	2,452†	2,452†			
API NC 46	152.4						3,238†	3,238†	3,100	2,808			
4 IF	158.7						3,874	3,550	3,100	2,808			
5 DSL	165.1						3,874	3,550	3,100	2,808			
4½ Mod. Open	171.4						3,874	3,550	3,100	2,808			
4½ H-90	146.0						2,491†	2,491†	2,491†	2,491†			
	152.4						3,274†	3,274†	3,202	2,910			
	158.7						3,972	3,650	3,202	2,910			
	165.1						3,972	3,650	3,202	2,910			
	171.4						3,972	3,650	3,202	2,910			
5 H-90	158.7						3,506†	3,506†	3,506†	3,506†			
	165.1						4,410†	4,410†	4,065	3,756			
	171.4						4,879	4,538	4,065	3,756			
	177.8						4,879	4,538	4,065	3,756			
5½ H-90	171.4						4,771†	4,771†	4,771†	4,720			
	177.8						5,806†	5,546	5,046	4,720			
	184.1						5,906	5,546	5,046	4,720			
	190.5						5,906	5,546	5,046	4,720			
5½ Reg	171.4						4,416†	4,416†	4,416†	4,416†			
	177.8						5,450†	5,450†	5,010	4,682			
	184.1						5,873	5,512	5,010	4,682			
	190.5						5,873	5,512	5,010	4,682			
4½ IF	158.7						3,180†	3,180†	3,180†	3,180†	3,180†		
API NC 50	165.1						4,103†	4,103†	4,103†	4,103†	3,688		
5 XH	171.4						5,080	4,953	4,462	4,143	3,688		
5 Mod. Open	177.8						5,306	4,953	4,462	4,143	3,688		
5½ DSL	184.1						5,306	4,953	4,462	4,143	3,688		
5 Semi-IF	190.5						5,306	4,953	4,462	4,143	3,688		

1. Basis of calculations for recommended makeup torque assumes the use of an API recommended thread compound containing 40 to 60% by weight of finely powdered metallic zinc with not more than 0.3% total active sulfur, applied thoroughly to all threads and shoulders. Also using the modified screw jack formula as shown in the IADC Drilling Manual and the API Recommended Practice RP 7G. For API connections and their interchangeable connections, makeup torque is based on 62,500 psi stress in the pin or box, whichever is weaker.

Recommended Minimum Makeup Torque, kg.m [See Note 2]

Size and Type of Connection, in.	OD, mm	Bore of Drill Collars, mm											
		25.4	31.7	38.1	44.4	50.8	57.1	63.5	71.4	76.2	82.5	88.9	95.2
5½ FH	177.8							4,530†	4,530†	4,530†	4,530†		
	184.1							5,668†	5,668†	5,668†	5,668†		
	190.5							6,866†	6,603	6,248	5,742		
	196.8							7,146	6,603	6,248	5,742		
API NC 56	184.1							5,599†	5,599†	5,599†	5,599†		
	190.5							6,783†	6,667	6,316	5,815		
	196.8							7,205	6,667	6,316	5,815		
	203.2							7,205	6,667	6,316	5,815		
6⅝ Reg	190.5							6,415†	6,415†	6,415†	6,415†		
	196.8							7,691†	7,375	7,010	6,489		
	203.2							7,935	7,375	7,010	6,489		
	209.5							7,935	7,375	7,010	6,489		
6⅝ H-90	190.5							6,430†	6,430†	6,430†	6,430†		
	196.8							7,702†	7,702†	7,414	6,893		
	203.2							8,340	7,780	7,414	6,893		
	209.5							8,340	7,780	7,414	6,893		
API NC 61	203.2							7,622†	7,622†	7,622†	7,622†		
	209.5							9,047†	9,047†	9,047†	8,520		
	215.9							10,047	9,456	9,070	8,520		
	222.2							10,047	9,456	9,070	8,520		
	228.6							10,047	9,456	9,070	8,520		
5½ IF	203.2							7,831†	7,831†	7,831†	7,831†	7,831†	
	209.5							9,282†	9,282†	9,282†	8,763	8,161	
	215.9							10,317	9,716	9,323	8,763	8,161	
	222.2							10,317	9,716	9,323	8,763	8,161	
	228.6							10,317	9,716	9,323	8,763	8,161	
	234.9							10,317	9,716	9,323	8,763	8,161	
6⅝ FH	215.9								9,372†	9,372†	9,372†	9,372†	9,289
	222.2								10,997†	10,997†	10,605	9,968	9,289
	228.6								11,612	11,197	10,605	9,968	9,289
	234.9								11,612	11,197	10,605	9,968	9,289
	241.3								11,612	11,197	10,605	9,968	9,289
API NC 70	228.6								10,477†	10,477†	10,477†	10,477†	10,477†
	234.9								12,277†	12,277†	12,277†	12,277†	12,277†
	241.3								14,151†	14,151†	13,979	13,302	12,579
	247.6								15,048	14,608	13,979	13,302	12,579
	254.0								15,048	14,608	13,979	13,302	12,579
	260.3								15,048	14,608	13,979	13,302	12,579
API NC 77	254.0									14,958†	14,958†	14,958†	14,958†
	260.3									17,151†	17,151†	17,151†	17,151†
	266.7									19,424†	19,424†	18,681	17,887
	273.0									20,113	19,423	18,681	17,887
	279.4									20,113	19,423	18,681	17,887
Connections with full faces													
7 H-90	203.2‡								7,390†	7,390†	7,390†	7,390†	
	209.5‡								8,812†	8,812†	8,812†	8,429	
	215.9‡								9,963	9,576	9,023	8,429	
7⅝ Reg	215.9‡									8,351†	8,351†	8,351†	8,351†
	222.2‡									9,978†	9,978†	9,978†	9,978†
	228.6‡									11,675†	11,644	10,996	10,304
	234.9‡									12,247	11,644	10,996	10,304
	241.3‡									12,247	11,644	10,996	10,304
7⅝ H-90	228.6‡									10,095†	10,095†	10,095†	10,095†
	234.9‡									11,891†	11,891†	11,891†	11,891†
	241.3‡									13,758†	13,758†	13,758†	13,312
8⅝ Reg	254.0‡									15,117†	15,117†	15,117†	15,117†
	260.3‡									17,318†	17,318†	17,318†	17,287
	266.7‡									19,512	18,823	18,081	17,287
8⅝ H-90	260.3‡									15,689†	15,689†	15,689†	15,689†
	266.7‡									17,982†	17,982†	17,982†	17,982†
Connections with low torque faces													
7 H-90	222.2								9,410†	9,410†	9,299	8,689	
	228.6								10,263	9,866	9,299	8,689	
7⅝ Reg	234.9									10,106†	10,106†	10,106†	10,106†
	241.3									11,954†	11,954†	11,400	10,686
	247.6									12,690	12,069	11,400	10,686
	254.0									12,690	12,069	11,400	10,686
7⅝ H-90	247.6									12,673†	12,673†	12,673†	12,673†
	254.0									14,691†	14,691†	14,401	13,659
	260.3									15,740	15,095	14,401	13,659
	266.7									15,740	15,095	14,401	13,659
8⅝ Reg	273.0									15,607†	15,607†	15,607†	15,607†
	279.4									18,067†	18,067†	18,067†	18,067†
	285.7									20,409	19,692	18,920	18,093
8⅝ H-90	273.0									12,852†	12,852†	12,852†	12,852†
	279.4									15,316†	15,316†	15,316†	15,316†
	285.7									17,863†	17,863†	17,863†	17,863†

2. Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

3. H-90 connections makeup torque is based on 56,200 psi stress and other factors as stated in Note 1.

4. The 2⅞-in. PAC makeup torque is based on 87,500 psi stress and other factors as stated in Note 1.

‡5. Largest diameter shown is the maximum recommended for these full faced connections. If larger diameters are used, machine connections with low torque faces and use the torque values shown under low torque face tables. If low torque faces are not used, see Note 2 for increased torque values.

†6. Torque figures succeeded by a dagger (†) indicate that the weaker member for the corresponding OD and bore is the box. For all other torque values the weaker member is the pin.

DRILL COLLARS

Recommended Minimum Makeup Torque, N·m [See Note 2]

Recommended Minimum Makeup Torque, N·m [See Note 2]

Size and Type of Connection, in.	OD, mm	Bore of Drill Collars, mm											
		25.4	31.7	38.1	44.4	50.8	57.1	63.5	71.4	76.2	82.5	88.9	95.2
API NC 23	76.20	3,400†	3,400†	3,400†									
	79.38	4,515†	4,515†	3,589									
	82.55	5,423	4,592	3,589									
2 ⅜ Reg	76.20		3,038†	3,038†	2,371								
	79.38		4,105†	3,490	2,371								
	82.55		4,454	3,490	2,371								
2 ⅞ PAC	76.20		5,148†	5,148†	3,967								
	79.38		6,733†	5,628	3,967								
	82.55		7,458	5,628	3,967								
2 ⅜ IF API NC 26 2 ⅞ SH	85.72		4,855†	4,855†	4,855†								
	88.90		6,245†	6,245†	5,012								
	95.25		7,458	6,329	5,012								
2⅞ Reg	88.90		5,204†	5,204†	5,204†								
	95.25		7,818	6,713	5,426								
	98.42		7,818	6,713	5,426								
2⅞ XH 3 ½ DSL 2 ⅞ Mod. Open	95.25		5,544†	5,544†	5,544†								
	98.42		7,256†	7,256†	7,256†								
	104.78		10,927†	10,927†	10,078								
2 ⅞ IF API NC 31 3 ½ SH	98.42		6,291†	6,291†	6,291†	6,291†	6,291†						
	104.78		10,019†	10,019†	10,019†	9,291	7,309						
	107.95		12,010†	12,010†	11,065	9,291	7,309						
	114.30		13,946	12,619	11,065	9,291	7,309						
3 ½ Reg	104.78		8,767†	8,767†	8,767†	8,767†	7,708						
	107.95		10,692†	10,692†	10,692†	9,647	7,708						
	114.30		14,197	12,899	11,381	9,647	7,708						
API NC 35	114.30				12,254†	12,254†	12,254†	10,048					
	120.65				16,640	14,678	12,476	10,048					
	127.00				16,640	14,678	12,476	10,048					
3 ½ XH 4 SH 3 ½ Mod. Open	107.95				6,997†	6,997†	6,997†	6,997†					
	114.30				11,496†	11,496†	11,496†	11,268					
	120.65				16,370†	16,003	13,753	11,268					
	127.00				18,009	16,003	13,753	11,268					
	133.35				18,009	16,003	13,753	11,268					
3 ½ IF API NC 38 4 ½ SH	120.65				13,539†	13,539†	13,539†	13,539†	11,274				
	127.00				18,912†	18,912†	17,500	14,883	11,274				
	133.35				21,974	19,867	17,500	14,883	11,274				
	139.70				21,974	19,867	17,500	14,883	11,274				
3 ½ H-90	120.65				11,910†	11,910†	11,910†	11,910†	11,910†				
	127.00				17,344†	17,344†	17,344†	17,344†	14,087				
	133.35				23,172†	22,927	20,497	17,806	14,087				
	139.70				25,085	22,927	20,497	17,806	14,087				
4 FH API NC 40 4 Mod. Open 4 ½ DSL	127.00				14,792†	14,792†	14,792†	14,792†	14,792†				
	133.35				20,730†	20,730†	20,730†	20,295	16,439				
	139.70				27,096†	25,606	23,087	20,295	16,439				
	146.05				27,847	25,606	23,087	20,295	16,439				
	152.40				27,847	25,606	23,087	20,295	16,439				
4 H-90	133.35				17,070†	17,070†	17,070†	17,070†	17,070†				
	139.70				23,593†	23,593†	23,593†	23,593†	22,420				
	146.05				30,548†	30,548†	29,440	26,497	22,420				
	152.40				34,449	32,094	29,440	26,497	22,420				
	158.75				34,449	32,094	29,440	26,497	22,420				
4 ½ Reg	139.70				21,118†	21,118†	21,118†	21,118†	21,118†				
	146.05				27,942†	27,942†	27,942†	26,575	22,546				
	152.40				34,447	32,114	29,488	26,575	22,546				
	158.75				34,447	32,114	29,488	26,575	22,546				
API NC 44	146.05				28,330†	28,330†	28,330†	28,330†	24,623				
	152.40				35,865†	34,586	31,852	28,821	24,623				
	158.75				37,014	34,586	31,852	28,821	24,623				
	165.10				37,014	34,586	31,852	28,821	24,623				
4 ½ FH	139.70					17,589†	17,589†	17,589†	17,589†	17,589†			
	146.05					24,566†	24,566†	24,566†	24,566†	24,269			
	152.40					32,004†	32,004†	31,222	27,008	24,269			
	158.75					37,006	34,264	31,222	27,008	24,269			
	165.10					37,006	34,264	31,222	27,008	24,269			
4 ½ XH API NC 46 4 IF 5 DSL 4 ½ Mod. Open	146.05						24,049†	24,049†	24,049†	24,049†			
	152.40						31,756†	31,756†	30,406	27,538			
	158.75						37,991	34,812	30,406	27,538			
	165.10						37,991	34,812	30,406	27,538			
	171.45						37,991	34,812	30,406	27,538			
4 ½ H-90	146.05						24,430†	24,430†	24,430†	24,430†			
	152.40						32,107†	32,107†	31,399	28,541			
	158.75						38,954	35,790	31,399	28,541			
	165.10						38,954	35,790	31,399	28,541			
	171.45						38,954	35,790	31,399	28,541			
5 H-90	158.75						34,384†	34,384†	34,384†	34,384†	32,523		
	165.10						43,244†	43,244†	39,861	36,834	32,523		
	171.45						47,850	44,505	39,861	36,834	32,523		
	177.80						47,850	44,505	39,861	36,834	32,523		
5 ½ H-90	171.45						46,787†	46,787†	46,787†	46,290	41,733		
	177.80						56,935†	54,391	49,489	46,290	41,733		
	184.15						57,919	54,391	49,489	46,290	41,733		
	190.50						57,919	54,391	49,489	46,290	41,733		
5 ½ Reg	171.45						43,306†	43,306†	43,306†	43,306†	41,347		
	177.80						53,445†	53,445†	49,128	45,919	41,347		
	184.15						57,597	54,051	49,128	45,919	41,347		
	190.50						57,597	54,051	49,128	45,919	41,347		
4 ½ IF API NC 50 5 XH 5 Mod. Open 5 ½ DSL 5 Semi-IF	158.7						31,188†	31,188†	31,188†	31,188†	31,188†		
	165.1						40,240†	40,240†	40,240†	40,240†	36,167		
	171.4						49,814†	48,570	43,762	40,628	36,167		
	177.8						52,035	48,570	43,762	40,628	36,167		
	184.1						52,035	48,570	43,762	40,628	36,167		
	190.5						52,035	48,570	43,762	40,628	36,167		

1. Basis of calculations for recommended makeup torque assumes the use of an API recommended thread compound containing 40 to 60% by weight of finely powdered metallic zinc with not more than 0.3% total active sulfur, applied thoroughly to all threads and shoulders. Also using the modified screw jack formula as shown in the IADC Drilling Manual and the API Recommended Practice RP 7G. For API connections and their interchangeable connections, makeup torque is based on 62,500 psi stress in the pin or box, whichever is weaker.

Recommended Minimum Makeup Torque, N·m [See Note 2]

Recommended Minimum Makeup Torque, N·m [See Note 2]

Size and Type of Connection, in.	OD, mm	Bore of Drill Collars, mm											
		25.4	31.7	38.1	44.4	50.8	57.1	63.5	71.4	76.2	82.5	88.9	95.2
5 ½ FH	177.80						44,419†	44,419†	44,419†	44,419†	44,419†		
	184.15						55,586†	55,586†	55,586†	55,586†	55,586†		
	190.50						67,331†	67,331†	64,748	61,269	56,311		
	196.85						73,912	70,078	64,748	61,269	56,311		
API NC 56	184.15							54,908†	54,908†	54,908†	54,908†		
	190.50							66,516†	65,379	61,934	57,023		
	196.85							70,657	65,379	61,934	57,023		
	203.20							70,657	65,379	61,934	57,023		
6⅝ Reg	190.50							62,909†	62,909†	62,909†	62,908†		
	196.85							75,420†	72,327	68,745	63,635		
	203.20							77,814	72,327	68,745	63,635		
	209.55							77,814	72,327	68,745	63,635		
6⅝ H-90	190.50							63,058†	63,058†	63,058†	63,058†		
	196.85							75,529†	75,529†	72,710	67,594		
	203.20							81,784	76,296	72,710	67,594		
	209.55							81,784	76,296	72,710	67,594		
API NC 61	203.2							74,748†	74,748†	74,748†	74,748†		
	209.5							88,722†	88,722†	88,722†	83,551		
	215.9							98,527	92,735	88,951	83,551		
	222.2							98,527	92,735	88,951	83,551		
	228.6							98,527	92,735	88,951	83,551		
5½ IF	203.2							76,796†	76,796†	76,796†	76,796†	75,796†	
	209.5							91,021†	91,021†	91,021†	85,933	80,030	
	215.9							101,178	95,215	91,431	85,933	80,030	
	222.2							101,178	95,215	91,431	85,933	80,030	
	228.6							101,178	95,215	91,431	85,933	80,030	
	234.9							101,178	95,215	91,431	85,933	80,030	
6⅝ FH	215.9							91,910†	91,910†	91,910†	91,910†	91,910†	91,089
	222.2							107,847†	107,847†	107,847†	103,999	97,757	91,089
	228.6							120,101	113,878	109,809	103,999	97,757	91,089
	234.9							120,101	113,878	109,809	103,999	97,757	91,089
	241.3							120,101	113,878	109,809	103,999	97,757	91,089
API NC 70	228.6							102,745†	102,745†	102,745†	102,745†	102,745†	102,745†
	234.9							120,399†	120,399†	120,399†	120,399†	120,399†	120,399†
	241.3							138,773†	138,773†	138,773†	137,083	130,449	123,358
	247.6							154,170	147,569	143,252	137,083	130,449	123,358
	254.0							154,170	147,569	143,252	137,083	130,449	123,358
	260.3							154,170	147,569	143,252	137,083	130,449	123,358
API NC 77	254.0							146,692†	146,692†	146,692†	146,692†	146,692†	146,692†
	260.3							168,191†	168,191†	168,191†	168,191†	168,191†	168,191†
	266.7							190,480†	190,480†	190,480†	190,476	183,197	175,409
	273.0							209,199	201,971	197,239	190,476	183,197	175,409
	279.4							209,199	201,971	197,239	190,476	183,197	175,409
Connections with full faces													
7 H-90	203.2‡							72,474†	72,474†	72,474†	72,474†	72,474†	72,474†
	209.5‡							86,417†	86,417†	86,417†	86,417†	82,664	76,444
	215.9‡							100,979	97,708	93,911	88,490	82,664	76,444
7⅝ Reg	215.9‡							81,894†	81,894†	81,894†	81,894†	81,894†	81,894†
	222.2‡							97,848†	97,848†	97,848†	97,848†	97,848†	97,848†
	228.6‡							114,488†	114,488†	114,488†	114,189	107,836	101,048
	234.9‡							130,567	124,238	120,098	114,189	107,836	101,048
	241.3‡							130,567	124,238	120,098	114,189	107,836	101,048
7⅝ H-90	228.60‡							98,998†	98,998†	98,998†	98,998†	98,998†	98,998†
	234.95‡							116,608†	116,608†	116,608†	116,608†	116,608†	116,608†
	241.30‡							134,915†	134,915†	134,915†	134,915†	134,915†	130,545
8⅝ Reg	254.00‡							148,252†	148,252†	148,252†	148,2512	148,252†	148,252†
	260.35‡							169,834†	169,834†	169,834†	169,834†	169,834†	169,523
	266.70‡							192,209†	192,209†	191,352	184,589	177,310	169,523
8⅝ H-90	260.35‡							153,861†	153,861†	153,861†	153,861†	153,861†	153,861†
	266.70‡							176,342†	176,342†	176,342†	176,342†	176,342†	176,342†
Connections with low torque faces													
7 H-90	222.25								92,278†	92,278†	91,188	85,206	78,815
	228.60								100,649	96,753	91,188	85,206	78,815
7⅝ Reg	234.95								99,109†	99,109†	99,109†	99,109†	99,109†
	241.30								117,228†	117,228†	117,228†	111,797	104,790
	247.65								124,449	124,449	118,352	111,797	104,790
	254.00								124,449	124,449	118,352	111,797	104,790
7⅝ H-90	247.65								124,284†	124,284†	124,284†	124,284†	124,284†
	254.00								144,069†	144,069†	144,069†	141,237	133,960
	260.35								158,783	154,361	148,039	141,237	133,960
	266.70								158,783	154,361	148,039	141,237	133,960
8⅝ Reg	273.05									153,054†	153,054†	153,054†	153,054†
	279.40									177,173†	177,173†	177,173†	177,173†
	285.75									200,140	193,108	185,538	177,436
8⅝ H-90	273.05									126,037†	126,037†	126,037†	126,037†
	279.40									150,200†	150,200†	150,200†	150,200†
	285.75									175,176†	175,176†	175,176†	175,176†

2. Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

3. H-90 connections makeup torque is based on 56,200 psi stress and other factors as stated in Note 1.

4. The 2⅞-in. PAC makeup torque is based on 87,500 psi stress and other factors as stated in Note 1.

‡5. Largest diameter shown is the maximum recommended for these full faced connections. If larger diameters are used, machine connections with low torque faces and use the torque values shown under low torque face tables. If low torque faces are not used, see Note 2 for increased torque values.

†6. Torque figures succeeded by a dagger (†) indicate that the weaker member for the corresponding OD and bore is the box. For all other torque values the weaker member is the pin.

DRILL COLLARS

Know Field Shop Work

When it becomes necessary to repair drill collars in a field shop, every effort should be made to rethread the drill collar with a joint equivalent to the original manufacturer's new joint. Use only field shops that are equipped with high-quality, hardened-and-ground gauges and that use with thread mills or lathes that use pre-formed threading inserts, cold rolling equipment and manganese or zinc phosphate coating baths.

Use the following checklist to ensure that the field shop's repair work is of high quality.

Straightness

Collars should be inspected by placing a support near each end and checking for run-out. As a rule, collars with more than ¼-in. (6-mm) run-out should be straightened.

Threading

Threads should be gauged with high-quality, hardened-and-ground gauges. Thread form, lead and taper should be inspected, using approved gauges. Thread roots should be free from sharp notches (see page 101 for oilfield thread forms).

Cold Working

Thread roots should be cold worked in accordance with procedures established for rolling or peening. Threads must be gauged for standoff prior to cold working.

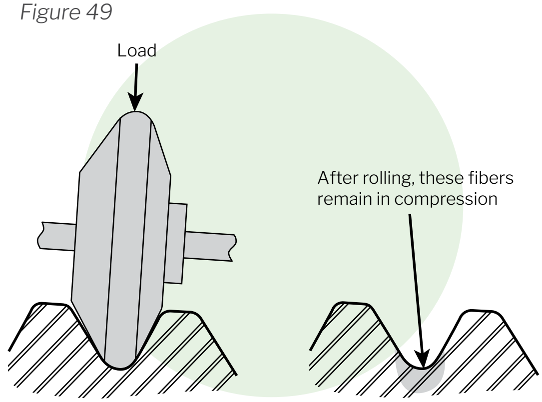
Cold working should be completed prior to cutting stress-relief contours so the last scratch of the run-out or imperfect thread root can be cold worked.

Facts About Cold Working

Drill collar joint life can be improved by prestressing the thread roots of drill collar joints by cold working. Cold working is done with a hydraulic ram which forces a roller into the thread root (Fig. 49). The roller is then moved down the thread spiral. Cold worked metal surfaces have greater resistance to fatigue failure. After thread rolling is completed, the fibers in the thread roots remain in compression and can withstand higher bending loads without cracking in fatigue.

Note: For comments related to the effect of cold working and gauge standoff, refer to API Specification No. 7.

Figure 49



Gall-Resistant Coating

A gall-resistant coating should be applied to all newly cut threads and shoulders. This conditions the shiny threads and shoulders so that lubricant will adhere to the surface.

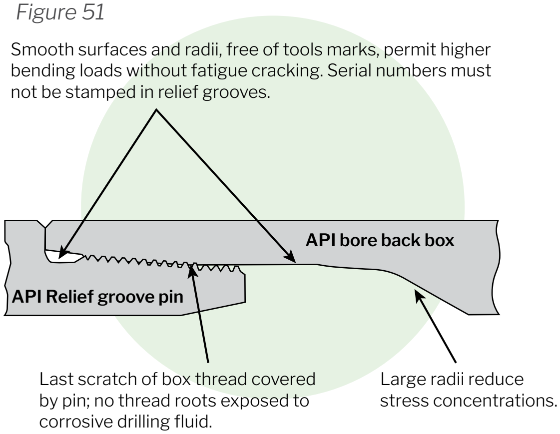
Newly machined threads are bright and shiny before being coated. The gall-resistant compound is usually a manganese or zinc phosphate coating, produced by immersing the thread in a hot chemical solution, which gives the threads and shoulders a dark appearance (Fig. 50). Such a coating acts as a lubricant, separates the metal surfaces during the initial makeup and assists in holding joint lubricant in place under makeup loads.

Figure 50

Stress Relief Contours

The API relief groove (pin) and the API bore back (box) remove nonengauged threads in highly stressed areas of the drill collar joint (see Fig. 51). This provides a more flexible joint, less likely to crack in fatigue, because bending in the joint occurs in areas of smooth relief surfaces.

Figure 51



Special Drill Collar Features

Spiral Drill Collars

The purpose of the spiral drill collar is to prevent differential sticking (see page 27). The reduction of wall contact between the drill collars and the wall of the openhole greatly reduces the chances of the collars becoming wall stuck.

The box end is left uncut for a distance of no less than 18 in. (457 mm) and no more than 24 in. (610 mm) below the shoulder.

The pin end is left uncut for a distance of no less than 12 in. (305 mm) and no more than 22 in. (559 mm) above the shoulder.

Note: The weight of a round drill collar will be reduced approximately 4 percent by spiraling.

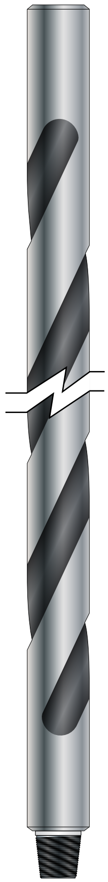


Figure 52

Slip and Elevator Recesses

Slip and elevator recesses are designed to cut drill collar handling time by eliminating lift subs and safety clamps. Extreme care is taken in machining smooth radii, free of tool marks. Added fatigue life is obtained by cold rolling the radii at the upper shoulder with a specially designed cold rolling tool. Slip and elevator recesses may be used together or separately (Fig. 53).

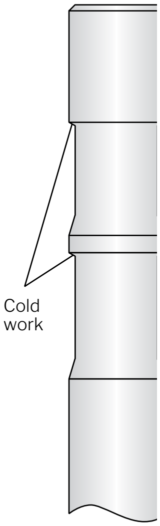


Figure 53

Low Torque Faces

To prevent shoulder separation, compressive stress created by the makeup torque must be such a magnitude that the shoulders remain together under all downhole conditions. On large diameter drill collars the shoulder can become so wide that the makeup torque required for an adequate compressive stress can not be obtained.

Low torque faces are used to achieve an increase in the compressive shoulder stress at the shoulder bevel when a connection smaller than optimum is used on large drill collars.

The low torque face feature is designed to accommodate the problem of reducing the area of the total shoulder face without creating a notch effect that would occur if a larger bevel is used.

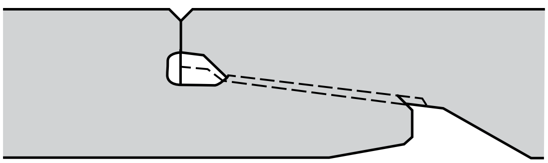
Instead of increasing bevel size to decrease the shoulder face area, the counterbore of the box is machined to a larger diameter to reduce the compressive box section at the shoulder.

The low torque feature cannot create a balance of fatigue life between the pin and box, nor can it increase the shoulder load holding the connection together.

It should be noted that the term Low Torque Feature does not mean that less makeup torque will be required when the feature is used on a particular connection on a given size collar.

Figure 54 is a comparison of the shoulder widths of a connection with and without a low torque feature.

Figure 54



Buoyancy Effect of Drill Collars in Mud

Total drill collar weight is not available to load the bit in fluid drilled holes due to the buoyancy effect on the drillstring in the fluid.

Buoyancy Factors

Mud, lbm/gal	Weight, lbm/ft3	g/cc or sp gr	Bouyancy correction factor
8.3	62.3	1.00	0.873
9	67.3	1.08	0.862
10	74.8	1.20	0.847
11	82.3	1.32	0.832
12	89.8	1.44	0.817
13	97.2	1.56	0.801
14	104.7	1.68	0.786
15	112.2	1.80	0.771
16	119.7	1.92	0.755
17	127.2	2.04	0.740
18	134.6	2.16	0.725
19	142.1	2.28	0.710
20	149.6	2.40	0.694
21	157.1	2.52	0.670
22	164.6	2.64	0.664
23	172.1	2.76	0.649
24	179.5	2.88	0.633

$$\text{BF} = 1 - \left(\frac{\text{mud lbm/gal}}{65.5} \right)$$

Buoyancy Factors

To find the corrected or buoyed drill collar weight, use the above buoyancy correction factor (BF) for the mud weight used.

Example: If a drill collar string weight is 79,000 lbm in air, how much will it weigh in 12 lbm/gal mud?

Buoyed drill collar weight = Drill collar weight x BF
= 79,000 lbm x .817
= 64,543 lbm

Example: If a drill collar string weight is 35,830 kg in air, how much will it weigh in 1.44 g/cc mud?

Buoyed drill collar weight = Drill collar weight x BF
= 35,834 kg x .817
= 29,276 kg

Drillpipe — Drill Collar Safety Factor

Drillpipe will be subjected to serious damage if run in compression. To make sure the drillpipe is always in tension, the top 10 to 15 percent of the drill collar string must also be in tension. This will put the change over from tension to compression, or neutral zone, in the stiff drill collar string where it is desirable and can be more tolerated. A percentage safety factor (SF) should be written as 10 percent, 1.10 or 15 percent, 1.15.

From the above buoyancy effect example, the maximum weight available to run on the bit would be:

$$\text{Maximum bit weight available} = \frac{\text{Buoyed weight}}{1.15} = \frac{64{,}543 \text{ lbm}}{1.15} = 56{,}124 \text{ lbm}$$

$$\text{Maximum bit weight available} = \frac{\text{Buoyed weight}}{1.15} = \frac{29{,}276 \text{ kg}}{1.15} = 25{,}457 \text{ kg}$$

$$\text{Drill collar air weight} = \frac{\text{Bit weight x SF}}{\text{BF}}$$

In soft formations with little or no bouncing, or when running a vibration dampener, a 10 percent safety factor will probably be sufficient. In areas of hard and rough drilling it may be desirable to increase this safety factor to 25 percent (x1.25).

Note: Treat drill collars like tools, not pipe. Guard tool joint pins and boxes from damage, lubricate them properly and these drill collars will provide trouble-free service.

Weight of 31 ft Drill Collar, lbm

Drill Collar OD, in.	Bore of Drill Collar, in.						
	1	1⅛	1¼	1½	1¾	2	2¼
3	662	640					
3⅛	726	704	679	622			
3¼	791	770	745	688			
3⅜			813	757	689		
3½			885	828	760		
3¾			1,035	978	910		
3⅞			1,114	1,057	989	912	824
4				1,138	1,071	993	905
4⅛				1,222	1,155	1,077	989
4¼				1,309	1,242	1,164	1,076
4½				1,490	1,423	1,345	1,257
4¾				1,681	1,614	1,536	1,448
5				1,883	1,816	1,738	1,650
5¼				2,095	2,028	1,950	1,862
5½				2,318	2,250	2,173	2,085
5¾				2,550	2,483	2,406	2,318
6				2,794	2,726	2,649	2,561
6¼				3,047	2,980	2,902	2,814
6½				3,311	3,244	3,166	3,078
6¾				3,585	3,518	3,440	3,352
7				3,870	3,802	3,725	3,637
7¼				4,164	4,097	4,020	3,932
7½				4,470	4,402	4,325	4,237
7¾				4,785	4,718	4,640	4,552
8				5,111	5,044	4,966	4,878
8¼				5,447	5,380	5,303	5,215
8½				5,794	5,727	5,649	5,561
8¾				6,151	6,084	6,006	5,918
9					6,451	6,373	6,285
9¼					6,629	6,751	6,663
9½					7,217	7,139	7,051
9¾					7,615	7,537	7,449
10						7,946	7,858
10¼						8,365	8,277
10½						8,794	8,706
10¾						9,234	9,146
11							
11¼							
11½							
11¾							
12							

1,000 lbm of steel will displace .364 bbl
65.5 lbm of steel will displace 1 gal
7.84 kg of steel will displace 1 liter
490 lbm of steel will displace 1 ft3
2,747 lbm of steel will displace 1 bbl

DRILL COLLARS

Weight of 31 ft Drill Collar, lbm

Bore of Drill Collar, in.							
2½	2 13/16	3	3¼	3½	3¾	4	4¼
1,350							
1,552							
1,764	1,627						
1,987	1,849	1,759					
2,219	2,082	1,992					
2,462	2,325	2,235	2,105	1,966			
2,716	2,579	2,488	2,359	2,219			
2,980	2,842	2,752	2,623	2,438			
3,254	3,117	3,026	2,897	2,757			
3,538	3,401	3,311	3,182	3,042	2,892	2,731	
3,833	3,696	3,606	3,476	3,337	3,187	3,026	
4,139	4,001	3,911	3,782	3,642	3,492	3,332	
4,454	4,317	4,227	4,097	3,957	3,807	3,647	
4,780	4,643	4,552	4,423	4,283	4,133	3,973	3,802
5,116	4,979	4,889	4,759	4,620	4,470	4,309	4,139
5,463	5,325	5,235	5,106	4,966	4,816	4,656	4,485
5,820	5,682	5,592	5,463	5,323	5,173	5,013	4,842
6,187	6,050	5,960	5,830	5,691	5,540	5,380	5,209
6,565	6,427	6,337	6,208	6,068	5,918	5,758	5,587
6,953	6,815	6,725	6,596	6,456	6,306	6,146	5,975
7,351	7,214	7,123	6,994	6,854	6,704	6,544	6,373
7,760	7,622	7,532	7,403	7,263	7,113	6,953	6,782
8,179	8,041	7,951	7,822	7,682	7,532	7,372	7,201
8,608	8,471	8,381	8,251	8,112	7,962	7,801	7,630
9,048	8,911	8,820	8,691	8,551	8,401	8,241	8,070
9,498	9,361	9,270	9,141	9,001	8,851	8,691	8,520
9,958	9,821	9,731	9,601	9,462	9,312	9,151	8,981
10,429	10,292	10,202	10,072	9,933	9,783	9,622	9,451
10,910	10,773	10,683	10,553	10,414	10,264	10,103	9,933
11,402	11,264	11,174	11,045	10,905	10,755	10,595	10,424

1,000 lbm of steel will displace .364 bbl
65.5 lbm of steel will displace 1 gal
7.84 kg of steel will displace 1 liter
490 lbm of steel will displace 1 ft^3
2,747 lbm of steel will displace 1 bbl

Drill Collar Weights, lbm/ft

Drill Collar OD, in.	Bore of Drill Collar, in.						
	1	1⅛	1¼	1½	1¾	2	2¼
3	21.4	20.7					
3⅛	23.4	22.7	21.9	20.1			
3¼	25.5	24.8	24.0	22.2			
3⅜			26.2	24.4	22.2		
3½			28.5	26.7	24.5		
3¾			33.4	31.5	29.4		
3⅞			35.9	34.1	31.9	29.4	26.6
4				36.7	34.5	32.0	29.2
4⅛				39.4	37.3	34.8	31.9
4¼				42.2	40.1	37.5	34.7
4½				48.1	45.9	43.4	40.6
4¾				54.2	52.1	49.6	46.7
5				60.7	58.6	56.1	53.2
5¼				67.6	65.4	62.9	60.1
5½				74.8	72.6	70.1	67.3
5¾				82.3	80.1	77.6	74.8
6				90.1	87.9	85.4	82.6
6¼				98.3	96.1	93.6	90.8
6½				106.8	104.6	102.1	99.3
6¾				115.6	113.5	111.0	108.1
7				124.8	122.7	120.2	117.3
7¼				134.3	132.2	129.7	126.8
7½				144.2	142.0	139.5	136.7
7¾				154.4	152.2	149.7	146.9
8				164.9	162.7	160.2	157.4
8¼				175.7	173.6	171.0	168.2
8½				186.9	184.7	182.2	179.4
8¾				198.4	196.2	193.7	190.9
9					208.1	205.6	202.8
9¼					220.3	217.8	214.9
9½					232.8	230.3	227.5
9¾					245.6	243.1	240.3
10						256.3	253.5
10¼						269.8	267.0
10½						283.7	280.9
10¾						297.9	295.0
11							
11¼							
11½							
11¾							
12							

1,000 lbm of steel will displace .364 bbl
65.5 lbm of steel will displace 1 gal
7.84 kg of steel will displace 1 liter
490 lbm of steel will displace 1 ft³
2,747 lbm of steel will displace 1 bbl

DRILL COLLARS

Drill Collar Weights, lbm/ft

Bore of Drill Collar, in.							
2½	2 13/16	3	3¼	3½	3¾	4	4¼
43.6							
50.1							
56.9	52.5						
64.1	59.6	56.7					
71.6	67.2	64.2					
79.4	75.0	72.1	67.9	63.4			
87.6	83.2	80.3	76.1	71.6			
96.1	91.7	88.8	84.6	80.1			
105.0	100.5	97.6	93.5	88.9			
114.1	109.7	106.8	102.6	98.1	93.3	88.1	
123.7	119.2	116.3	112.1	107.6	102.8	97.6	
133.5	129.1	126.2	122.0	117.5	112.6	107.5	
143.7	139.2	136.3	132.2	127.7	122.8	117.6	
154.2	149.8	146.9	142.7	138.2	133.3	128.2	122.7
165.0	160.6	157.7	153.5	149.0	144.2	139.0	133.5
176.2	171.8	168.9	164.7	160.2	155.4	150.2	144.7
187.7	183.3	180.4	176.2	171.7	166.9	161.7	156.2
199.6	195.2	192.2	188.1	183.6	178.7	173.6	168.0
211.8	207.3	204.4	200.3	195.7	190.9	185.7	180.2
224.3	219.9	216.9	212.8	208.3	203.4	198.3	192.7
237.1	232.7	229.8	225.6	221.1	216.3	211.1	205.6
250.3	245.9	243.0	238.8	234.3	229.5	224.3	218.8
263.8	259.4	256.5	252.3	247.8	243.0	237.8	232.3
277.7	273.3	270.3	266.2	261.7	256.8	251.7	246.1
291.9	287.4	284.5	280.4	275.8	271.0	265.8	260.3
306.4	302.0	299.0	294.9	290.4	285.5	280.4	274.8
321.2	316.8	313.9	309.7	305.2	300.4	295.2	289.7
336.4	332.0	329.1	324.9	320.4	315.6	310.4	304.9
351.9	347.5	344.6	340.4	335.9	331.1	325.9	320.4
367.8	363.4	360.5	356.3	351.8	346.9	341.8	336.3

1,000 lbm of steel will displace .364 bbl
65.5 lbm of steel will displace 1 gal
7.84 kg of steel will displace 1 liter
490 lbm of steel will displace 1 ft³
2,747 lbm of steel will displace 1 bbl

Weight of 9.4 m Drill Collar, kg

Drill Collar OD, in.	Bore of Drill Collar, in. [mm]						
	1 [25.4]	1⅛ [28.57]	1¼ [31.75]	1½ [38.10]	1¾ [44.45]	2 [50.80]	2¼ [57.15]
3	662.2	640.2					
3 ⅛	725.5	703.6	679.0	622.1			
3 ¼	791.5	769.5	744.9	688.0			
3 ⅜			813.5	756.6	689.3		
3 ½			884.6	827.7	760.5		
3 ¾			1,034.6	977.7	910.5		
3 ⅞			1,113.5	1,056.6	989.4	911.8	823.8
4				1,138.1	1,070.9	993.3	905.3
4 ⅛				1,222.2	1,154.9	1,077.3	989.4
4 ¼				1,308.0	1,241.6	1,164.0	1,076.0
4 ½				1,489.9	1,422.6	1,345.0	1,257.1
4 ¾				1,681.3	1,614.0	1,536.4	1,448.5
5				1,883.0	1,815.8	1,738.2	1,650.3
5 ¼				2,095.2	2,027.9	1,950.3	1,862.4
5 ½				2,317.6	2,250.3	2,172.7	2,084.8
5 ¾				2,550.4	2,483.1	2,405.5	2,317.6
6				2,793.5	2,726.3	2,648.7	2,560.7
6 ¼				3,047.0	2,979.8	2,902.2	2,814.2
6 ½				3,310.9	3,243.6	3,166.0	3,078.1
6 ¾				3,585.0	3,517.8	3,440.2	3,352.2
7				3,869.6	3,802.3	3,724.7	3,636.8
7 ¼				4,164.4	4,097.2	4,019.6	3,931.6
7 ½				4,469.7	4,402.4	4,324.8	4,236.9
7 ¾				4,785.2	4,718.0	4,640.4	4,552.4
8				5,111.1	5,043.9	4,966.3	4,878.3
8 ¼				5,447.4	5,380.1	5,302.5	5,214.6
8 ½				5,794.0	5,726.7	5,649.1	5,561.2
8 ¾				6,150.9	6,083.7	6,006.1	5,918.2
9					6,451.0	6,373.4	6,285.4
9 ¼					6,628.6	6,751.0	6,663.1
9 ½					7,216.6	7,139.0	7,051.1
9 ¾					7,615.0	7,537.4	7,449.4
10						7,946.1	7,858.1
10 ¼						8,365.1	8,277.1
10 ½						8,794.5	8,706.5
10 ¾						9,234.2	9,146.2
11							
11 ¼							
11 ½							
11 ¾							
12							

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Weight of 9.4 m Drill Collar, kg

Bore of Drill Collar, in. [mm]							
2½ [63.50]	2¹³⁄₁₆ [71.44]	3 [76.20]	3¼ [82.55]	3½ [88.9]	3¾ [92.3	4 [101.6]	4¼ [108.0]
1,350.2							
1,552.0							
1,764.1	1,626.7						
1,986.5	1,849.1	1,758.9					
2,219.3	2,081.9	1,991.7					
2,462.4	2,325.0	2,234.8	2,105.5	891.6			
2,715.9	2,578.5	2,488.3	2,359.0	1,006.3			
2,979.8	2,842.4	2,752.1	2,622.8	1,105.7			
3,253.9	3,116.5	3,026.3	2,897.0	1,250.3			
3,538.5	3,401.1	3,310.9	3,181.5	1,379.6	1,311.6	1,238.5	
3,833.3	3,695.9	3,605.7	3,476.4	1,513.4	1,445.4	1,372.3	
4,138.6	4,001.2	3,910.9	3,781.6	1,651.7	1,583.7	1,511.1	
4,454.1	4,316.7	4,226.5	4,097.2	1,794.6	1,726.5	1,654.0	
4,780.0	4,642.6	4,552.4	4,423.1	1,942.4	1,893.4	1,801.8	1,724.3
5,116.3	4,978.9	4,888.7	4,759.4	2,095.2	2,027.2	1,954.2	1,877.1
5,462.9	5,325.5	5,235.3	5,106.0	2,252.2	2,184.1	2,111.6	2,034.0
5,819.9	5,682.4	5,592.2	5,462.9	2,414.1	2,346.0	2,273.5	2,195.9
6,187.2	6,049.7	5,959.5	5,830.2	2,580.9	2,512.5	2,439.9	2,362.4
6,564.8	6,427.4	6,337.2	6,207.9	2,751.9	2,683.9	2,611.3	2,533.8
6,952.8	6,815.4	6,725.2	6,595.8	2,927.9	2,859.9	2,787.3	2,709.8
7,351.1	7,213.7	7,123.5	6,994.2	3,108.4	3,040.4	2,967.8	2,809.3
7,759.8	7,622.4	7,532.2	7,402.9	3,293.9	3,234.9	3,153.3	3,075.7
8,178.8	8,041.4	7,951.2	7,821.9	3,843.9	3,415.9	3,343.3	3,265.8
8,608.2	8,470.8	8,380.6	8,251.3	3,683.4	3,610.9	3,537.9	3,460.3
9,047.9	8,910.5	8,820.3	8,691.0	3,878.0	3,810.0	3737.4	3,590 .0
9,498.0	9,360.6	9,270.4	9,141.1	4,072.1	4,014.0	3,941.5	3,863.9
9,958.4	9,821.0	9,730.8	9,601.5	4,391.2	4,223.1	4,150.1	4,073.0
10,429.2	10,291.8	10,201.6	10,072.2	4,504.8	4,436.7	4,363.7	4,286.2
10,910.3	10,772.9	10,682.7	10,553.3	4,722.9	4,654.9	4,589.9	4,504.8
11,401.8	11,264.3	11,174.1	11,044.8	4,945.6	4,877.6	4,805.0	4,727.4

1,000 lbm of steel will displace .364 bbl
65.5 lbm of steel will displace 1 gal
7.84 kg of steel will displace 1 liter
490 lbm of steel will displace 1 ft³
2,747 lbm of steel will displace 1 bbl

Drill Collar Weights, kg/m

Drill Collar OD, in.	Bore of Drill Collar, in. [mm]						
	1 [25.4]	1⅛ [28.57]	1¼ [31.75]	1½ [38.10]	1¾ [44.45]	2 [50.80]	2¼ [57.15]
3	32	31					
3⅛	35	34	33	30			
3¼	38	37	36	33			
3⅜			39	36	33		
3½			43	40	37		
3¾			50	47	44		
3⅞			54	51	48	44	40
4				55	51	48	44
4⅛				59	55	52	48
4¼				63	60	56	52
4½				72	68	65	60
4¾				81	78	74	70
5				90	87	83	79
5¼				101	97	94	89
5½				111	108	104	100
5¾				122	119	116	111
6				134	131	127	123
6¼				146	143	139	135
6½				159	156	152	148
6¾				172	169	165	161
7				186	183	179	175
7¼				200	197	193	189
7½				215	211	208	203
7¾				230	227	223	219
8				245	242	238	234
8¼				262	258	255	250
8½				278	275	271	267
8¾				295	292	288	284
9					310	306	302
9¼					328	324	320
9½					346	343	339
9¾					366	362	358
10						382	377
10¼						402	397
10½						422	418
10¾						443	439
11							
11¼							
11½							
11¾							
12							

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Drill Collar Weights, kg/m

Bore of Drill Collar, in. [mm]							
2½ [63.50]	2 13/16 [71.44]	3 [76.20]	3¼ [82.55]	3½ [88.9]	3¾ [92.3	4 [101.6]	4¼ [108.0]
65							
75							
85	78						
95	89	84					
107	100	96					
118	112	107	101	206			
130	124	120	113	236			
143	136	132	126	262			
156	150	145	139	292			
170	163	159	153	321	305	289	
184	177	173	167	354	338	321	
199	192	188	182	387	371	354	
214	207	203	197	420	403	387	
230	223	219	212	453	436	420	403
246	239	235	229	489	472	456	440
262	256	251	245	525	508	492	476
279	273	269	262	564	548	531	512
297	290	286	280	604	587	571	551
315	309	304	298	643	626	610	590
334	327	323	317	682	666	649	633
353	346	342	336	725	708	692	676
373	366	362	355	768	754	735	718
393	386	362	355	813	797	781	761
413	407	403	396	859	843	827	807
434	428	423	417	905	889	872	853
456	449	445	439	951	938	918	902
478	472	467	461	1,000	984	968	951
501	494	490	484	1,050	1,036	1,017	1,000
524	517	513	507	1,102	1,086	1,069	1,050
547	541	536	530	1,155	1,138	1,122	1,102

1,000 lbm of steel will displace .364 bbl
65.5 lbm of steel will displace 1 gal
7.84 kg of steel will displace 1 liter
490 lbm of steel will displace 1 ft³
2,747 lbm of steel will displace 1 bbl

Preventing Pin and Box Failures in Downhole Tools

The API rotary shouldered connection is simple and rugged but since its acceptance in the early part of the 20th century drilling conditions have changed drastically. New proprietary connections are available for harsh conditions including higher hanging loads, higher pressures and corrosives environments with high concentrations of hydrogen sulfide, carbon dioxide and free chlorides. It should be noted that any connection is subject to fatigue failure if it's asked to work beyond its endurance limit, or if a few simple rules are not followed in its manufacture and use.

DRILCO has written detailed booklets on care and use of drill collars. This information can be obtained from the local DRILCO and Wellbore Integrity Solutions locations. However, if a few simple rules listed below are followed fatigue failures can be drastically reduced.

- **Use correct makeup torque:** Experience indicates that 80% or more of all premature connection failures are due to incorrect makeup torque (see pages 37 through 53).
- **Use proper thread compound:** A good grade of tool joint compound contains powdered metallic zinc in the amount of 40 to 60% by weight (see page 38).
- **Proper tong position:** Position tongs 8 in. (203 mm) below the box shoulder. The torque indicator should be located in the snub line 90° to tong arm (see pages 40 through 50).
- **Use systematic inspection:** Fatigue is an accumulative and progressive problem. Cracks ordinarily exist a long time before ultimate failure and can be detected by proper inspection methods (see pages 153 through 166).
- **Require best joint design and processing:** Much has been learned about how tool joint design and machining methods affect fatigue resistance (stress level) (see pages 37 through 53).
- **Insist on factory quality from field shops:** To the extent possible, require the same machining and processing used by drill collar manufacturers from the field shops used to repair drill collars in the field (see page 68).
- **Treat tools like machinery not pipe:** Guard pins and boxes from damage, lubricate them properly and they will provide extended service life.

Drill Collar Problems That Cannot be Explained

Should you have problems with drill collars from a DRILCO or Wellbore Integrity Solutions source, call or email your local DRILCO representative.

When contacting DRILCO or Wellbore Integrity Solutions about a drill collar problem, please specify:

1. Connection size and type, relief features, and length.
2. OD and ID of drill collars.
3. Torque applied.
4. Length of tongs.
5. Type of torque indicator.
6. Service time of connections.
7. Location of failure (pin or box).
8. Type of thread compound.
9. Drilling conditions.

Guides for Evaluating Drill Collar OD, ID and Connection Combinations

The bending strength ratio (BSR) is used in the following charts as a basis for evaluating compatibility of drill collar OD, ID and connection type combinations. The BSR is a number descriptive of the relative capacity of the pin and box to resist bending fatigue failures. It is generally accepted that a BSR of 2.50:1 is the right number for the average balanced connection, when drilling conditions are average.

If you study the BSR ratios in the API RP 7G, you will realize that very few of the ODs and IDs commonly used on drill collars result in a BSR of 2.50:1 exactly, so the following charts were prepared using the guidelines listed below:

1. For small drill collars 6-in. (152.4-mm) OD and below, try to avoid BSRs above 2.75:1 or below 2.25:1.
2. For high rotary speeds , soft formations and when drill collar OD is small compared to hole size (example: 8-in. (203.2-mm) OD in a $12\frac{1}{4}$-in. (311.2-mm) hole, 6-in. (152.4-mm) OD in $8\frac{1}{4}$-in. (209.6-mm) hole), avoid BSRs above 2.85:1 or below 2.25:1.
3. For hard formations, low rotary speeds and when drill collar OD is close to the hole size (example: 10-in. (254.0-mm) OD in a $12\frac{1}{4}$-in. (311.2-mm) hole, $8\frac{1}{4}$-in. (209.6-mm) OD in a $9\frac{7}{8}$-in. (250.8-mm) hole, avoid BSRs above 3.20:1 or below 2.25:1. However, when low torque features (see page 75) are used on large drill collars, BSRs as large as 3.40:1 will perform satisfactorily.
4. For very abrasive conditions where loss of OD is severe, combinations of 2.50:1 to 3.00:1 are recommended.
5. For extremely corrosive environments, combinations of 2.50:1 to 3.00:1.81 are recommended.

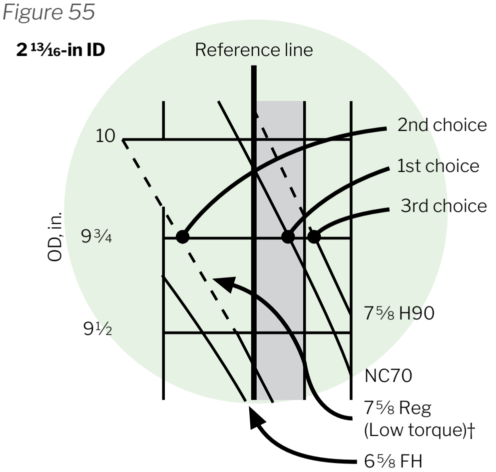
Using the connection selection charts on pages 84 through 99.

The charts appearing on pages 84 to 99 were prepared with the BSR guidelines as reference.

1. The best group of connections are defined as those that appear in the shaded sections of the charts. Also the nearer the connection lies to the reference line, the more desirable is its selection.
2. The second best group of connections are those that lie in the non shaded section of the charts on the left. The nearer the connection lies to the reference line, the more desirable is its selection.
3. The third best group of connections are those that lie in the non shaded section of the charts on the right. The nearer the connection lies to the reference line, the more desirable is its selection.

Example: If the best connection for a $9\frac{3}{4}$-in. (247.7-mm) x $2\frac{13}{16}$-in. (71.4-mm) ID drill collar is desired refer to the following chart on pages 84-99 and see Figure 55 for an explanation of the usage of the charts.

Figure 55



For average conditions, tool joints should selected in the order of preference below:

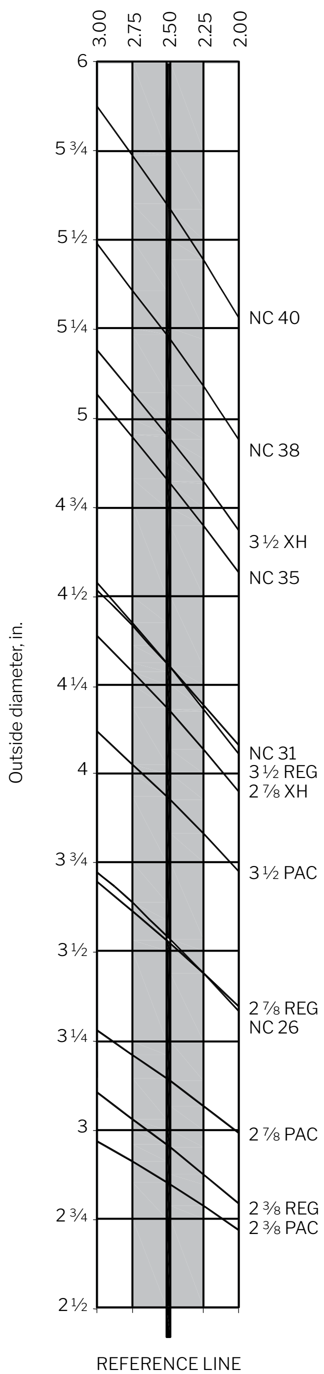
1. Best = NC70 (shaded area and nearest reference line).
2. Second best = $7\frac{5}{8}$ Reg (low torque) (light area to left and nearest to reference line).
3. Third best = $7\frac{5}{8}$ H90 (light area to right and nearest to reference line).

But in extremely abrasive and/or corrosive conditions, you might want to select in this order of preference:

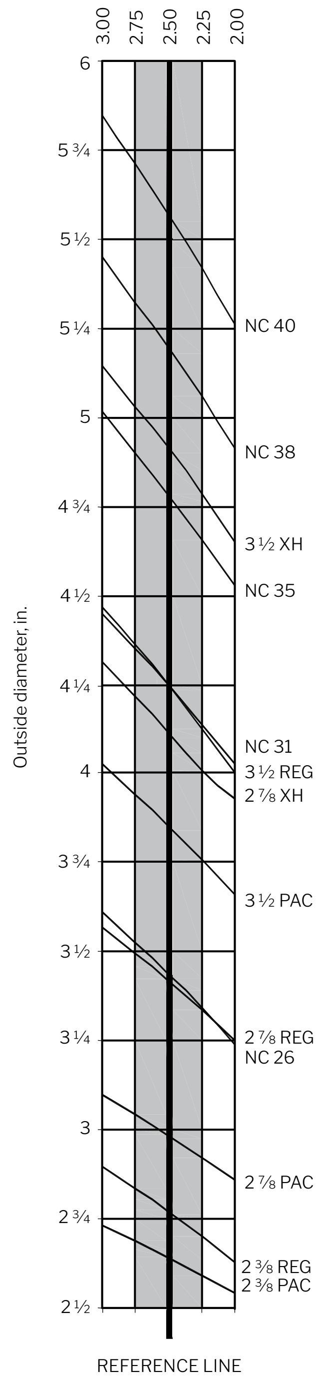
1. Best = $7\frac{5}{8}$ Reg (low torque) = strongest box†
2. Second best = NC70 = second strongest box
3. Third best = $7\frac{5}{8}$ H90 = weakest box

† The connection furthest to the left on the chart has the strongest box. This connection should be considered as possible first choices for very abrasive formations or corrosive conditions.

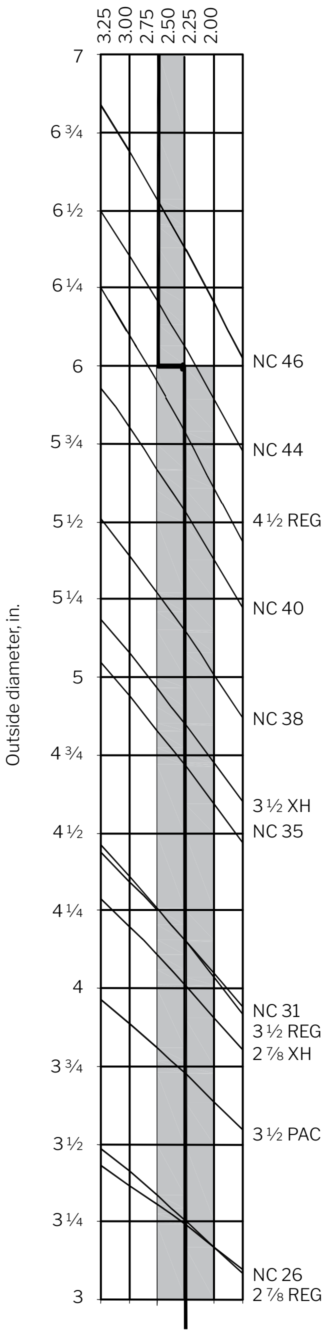
1½-in. ID



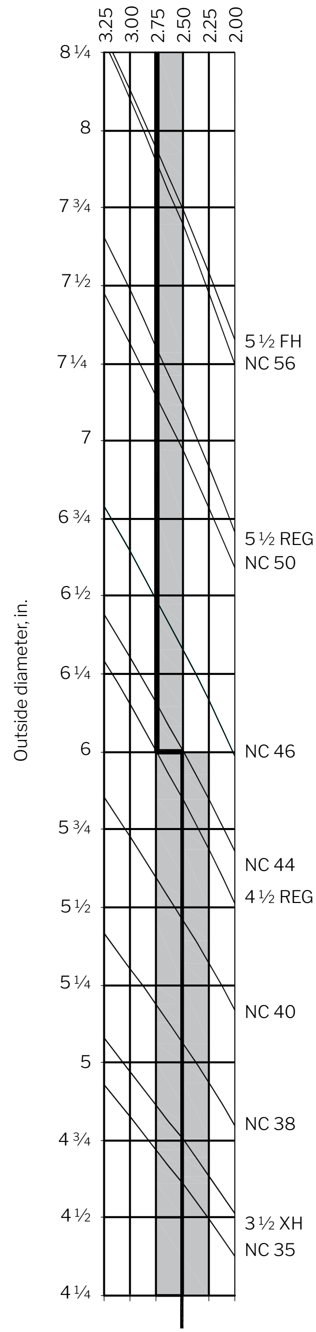
1¾-in. ID



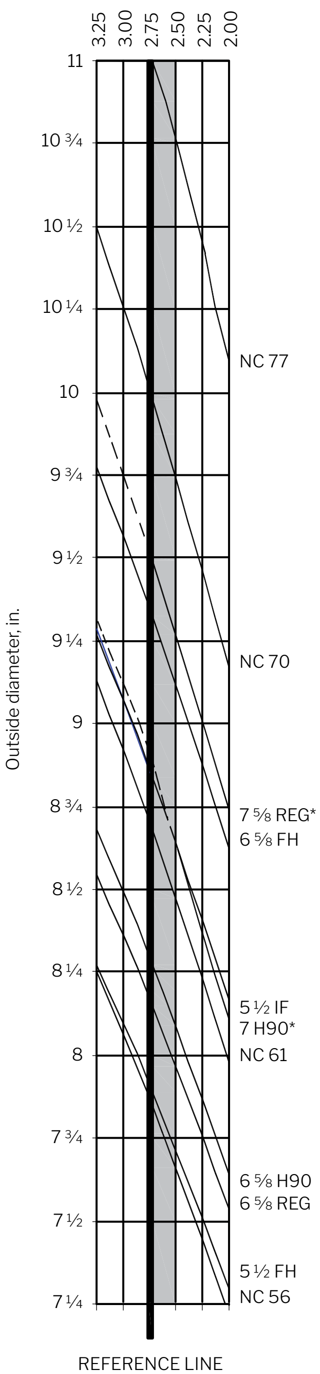
2-in. ID



2¼-in. ID

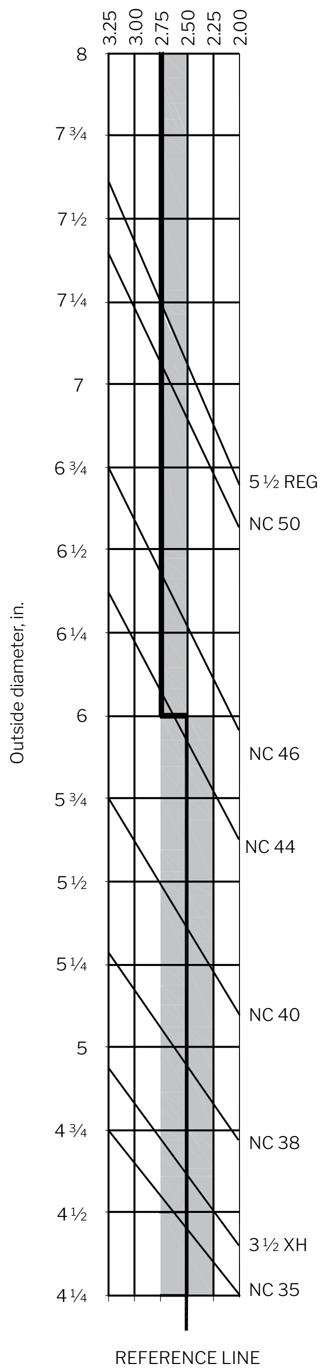


2½-in. ID

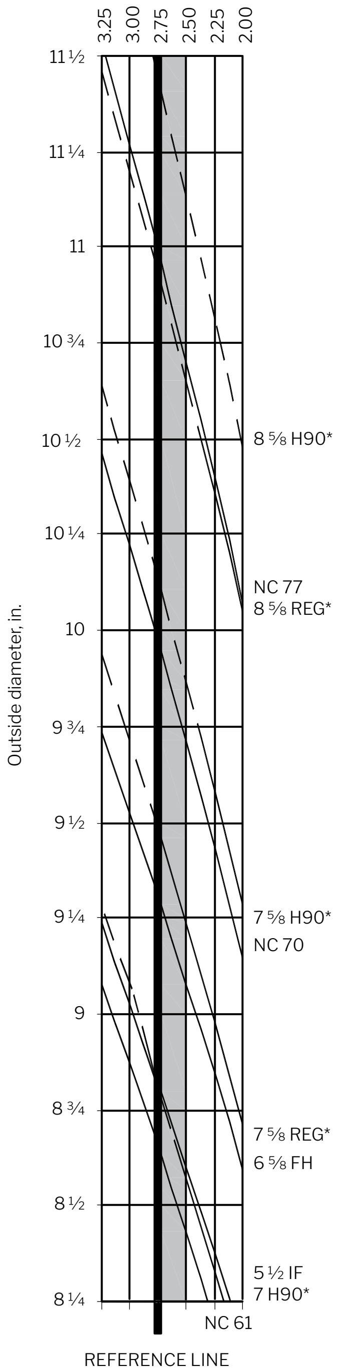


† On ODs where these connections are noted by a dotted line, they must be machined with a low torque face for proper makeup. (See page 69 for explanation of low torque face.)

2½-in. ID

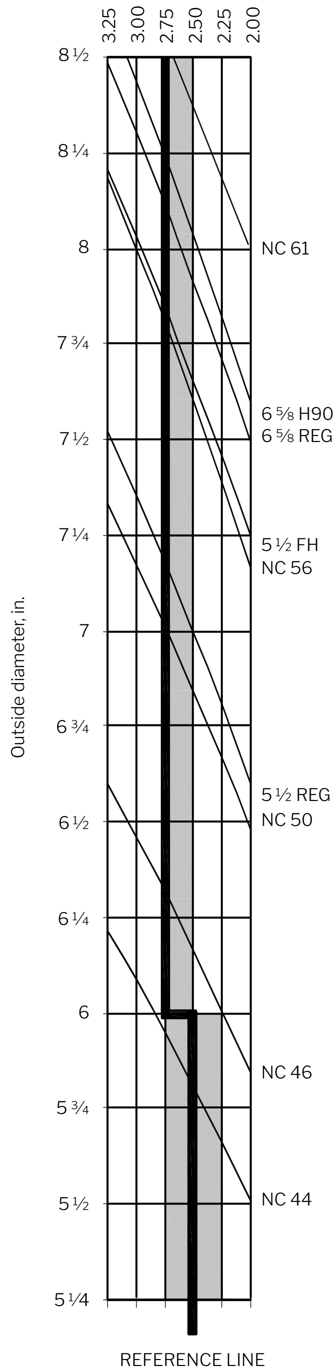


2^{13}/16-in. ID



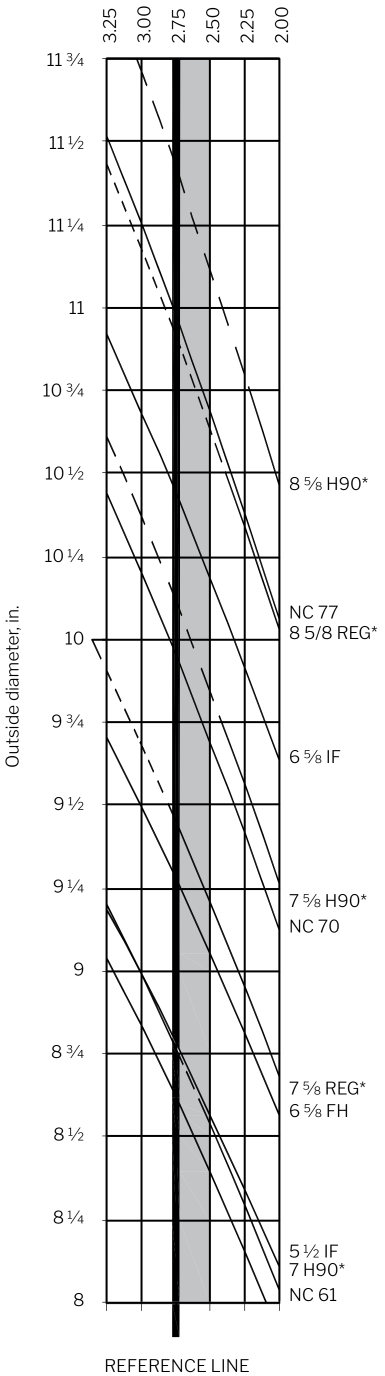
† On ODs where these connections are noted by a dotted line, they must be machined with a low torque face for proper makeup. (See page 69 for explanation of low torque face.)

2^{13}/16-in. ID



† On ODs where these connections are noted by a dotted line, they must be machined with a low torque face for proper makeup. (See page 69 for explanation of low torque face.)

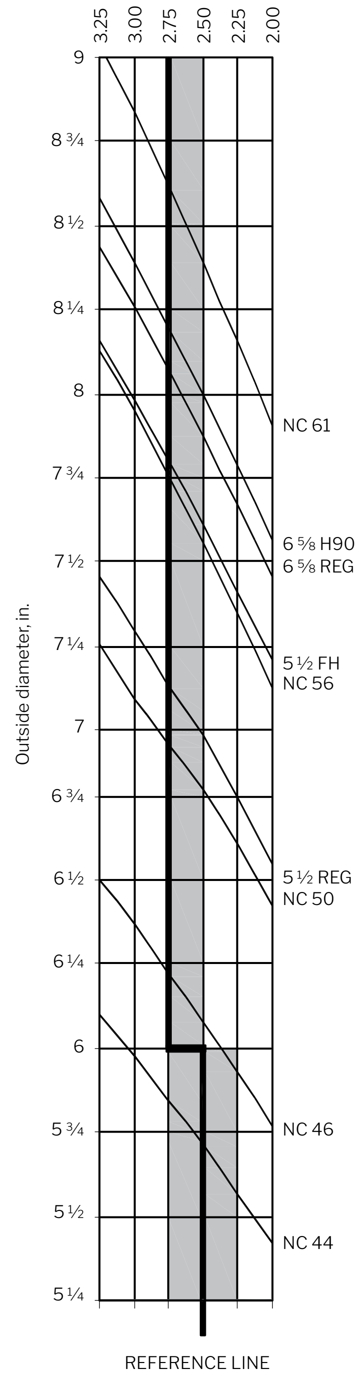
3-in. ID



† On ODs where these connections are noted by a dotted line, they must be machined with a low torque face for proper makeup. (See page 69 for explanation of low torque face.)

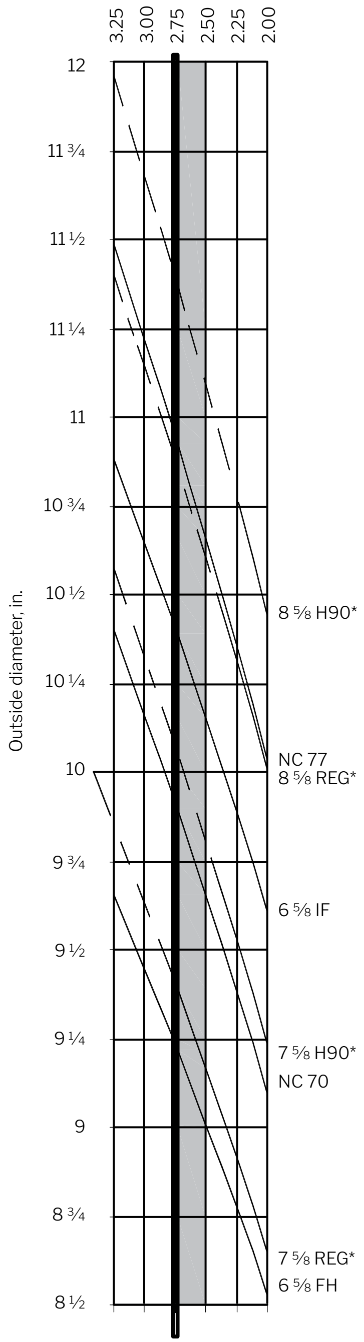
DRILL COLLARS

3-in. ID



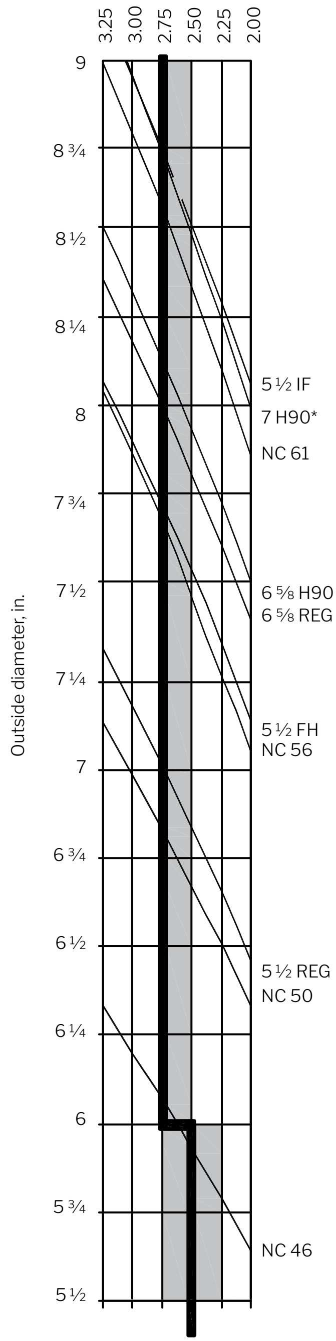
† On ODs where these connections are noted by a dotted line, they must be machined with a low torque face for proper makeup. (See page 69 for explanation of low torque face.)

3¼-in. ID



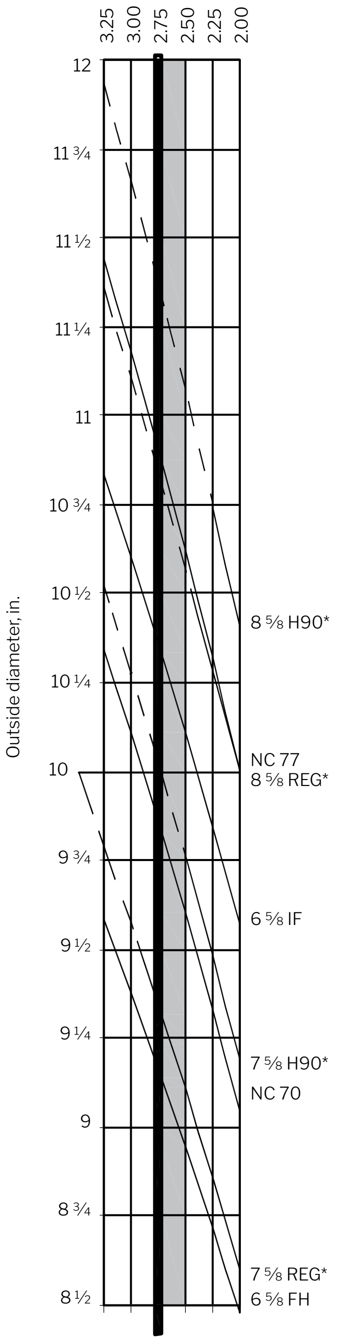
† On ODs where these connections are noted by a dotted line, they must be machined with a low torque face for proper makeup. (See page 69 for explanation of low torque face.)

3¼-in. ID



† On ODs where these connections are noted by a dotted line, they must be machined with a low torque face for proper makeup. (See page 69 for explanation of low torque face.)

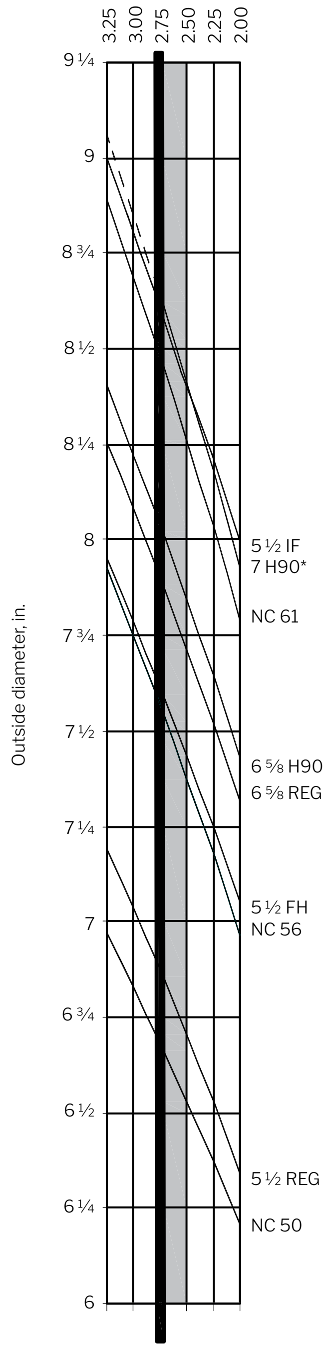
3½-in. ID



† On ODs where these connections are noted by a dotted line, they must be machined with a low torque face for proper makeup. (See page 69 for explanation of low torque face.)

DRILL COLLARS

3½-in. ID



† On ODs where these connections are noted by a dotted line, they must be machined with a low torque face for proper makeup. (See page 69 for explanation of low torque face.)

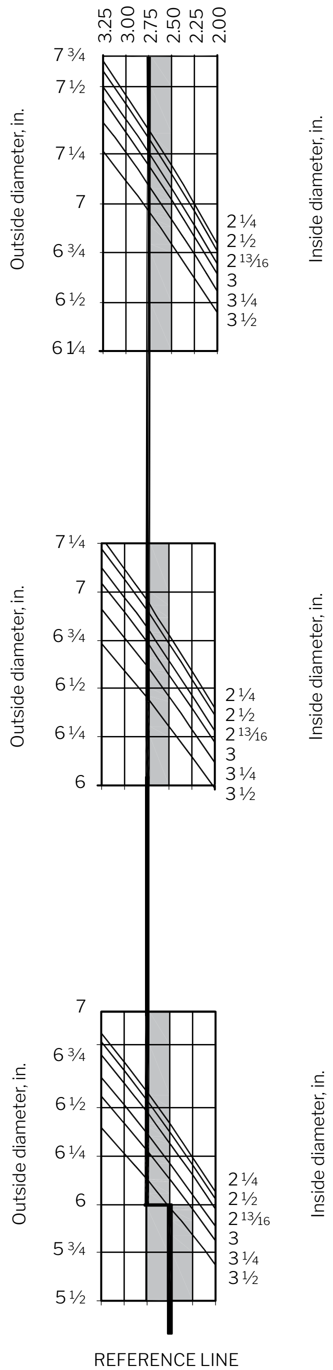
DRILL COLLARS

3½ H-90 to 5½ H-90 Selection Charts

5½ H-90

5 H-90

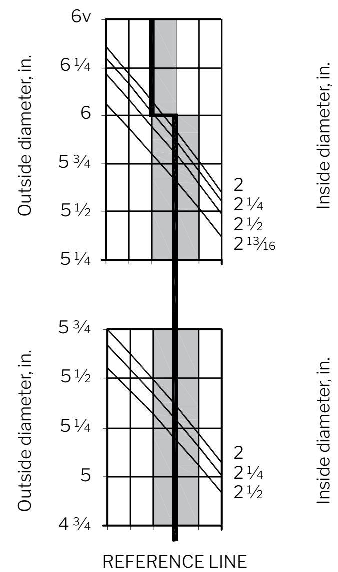
4½ H-90



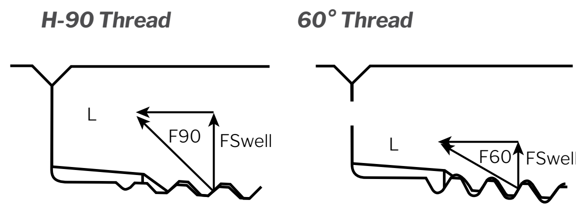
3½ H-90 to 5½ H-90 Selection Charts

4 H-90

3½ H-90



Caution: *The use of the 90° thread form on drill collar sizes less than 7½-in. OD may result in hoop stresses high enough to cause swelled boxes. For this reason the API 60° thread form is preferred over the above sizes of the 90° thread form.*



In order to produce the same shoulder load (L) — see illustration — on connections of the same size but with different threads (H-90 and 60°), the makeup torque must produce a greater force (F90) for an H-90 thread than for a 60° thread (F60). This means the torque requirement is greater for the H-90 thread than the 60° thread, if the connections are equal size. When the makeup torque produces the same shoulder load on both connections, then the force on the H-90 box (F swell) is greater than the force on the 60° box (F swell). This results in high hoop stresses in boxes with H-90 threads.

Rotary Shouldered Connection Interchange List

Common Name		Pin Base Diameter [tapered], in.	Threads per Inch	Taper, in./ft	Thread Form	Same as or Interchanges With, in.
Style	Size, in.					
Internal Flush (IF)	2 3/8	2.876	4	2	V-0.065 (V-0.038 rad)	2 7/8 SH NC 26‡
	2 7/8	3.391	4	2	V-0.065 (V-0.038 rad)	3 1/2 SH NC 31‡
	3 1/2	4.106	4	2	V-0.065 (V-0.038 rad)	4 1/2 SH NC 38‡
	4	4.834	4	2	V-0.065 (V-0.038 rad)	4 1/2 XH NC 46‡
	4 1/2	5.250	4	2	V-0.065 (V-0.038 rad)	5 XH NC 50‡ 5 1/2 DSL
Full Hole (FH)	4	4.280	4	2	V-0.065 (V-0.038 rad)	4 1/2 DSL NC 40‡
Extra Hole (XH) (EH)	2 7/8	3.327	4	2	V-0.065 (V-0.038 rad)	3 1/2 DSL
	3 1/2	3.812	4	2	V-0.065 (V-0.038 rad)	4 SH
	4 1/2	4.834	4	2	V-0.065 (V-0.038 rad)	4 IF NC 46‡
	5	5.520	4	2	V-0.065 (V-0.038 rad)	4 1/2 IF NC 50‡ 5 1/2 DSL
Slim Hole (SH)	2 7/8	2.876	4	2	V-0.065 (V-0.038 rad)	2 3/8 IF NC 26‡
	3 1/2	3.391	4	2	V-0.065 (V-0.038 rad)	2 7/8 IF NC 31‡
	4	3.812	4	2	V-0.065 (V-0.038 rad)	3 1/2 XH
	4 1/2	4.016	4	2	V-0.065 (V-0.038 rad)	3 1/2 IF NC 38‡
Double Streamline (DSL)	3 1/2	3.327	4	2	V-0.065 (V-0.038 rad)	2 7/8 XH
	4 1/2	4.280	4	2	V-0.065 (V-0.038 rad)	4 FH NC 40‡
	5 1/2	5.250	4	2	V-0.065 (V-0.038 rad)	4 1/2 IF 5 XH NC 50‡
Num. Conn. (NC)	26	2.876	4	2	V-0.038 rad	2 3/8 IF 2 7/8 SH
	31	3.391	4	2	V-0.038 rad	2 7/8 IF 3 1/2 SH
	38	4.016	4	2	V-0.038 rad	3 1/2 IF 4 1/2 SH
	40	4.280	4	2	V-0.038 rad	4 FH 4 1/2 DSL
	46	4.834	4	2	V-0.038 rad	4 IF 4 1/2 XH
	50	5.250	4	2	V-0.038 rad	4 1/2 IF 5 XH 5 1/2 DSL

†*Connections with two thread forms shown may be machined with either thread form without affecting gauging or interchangeability.*

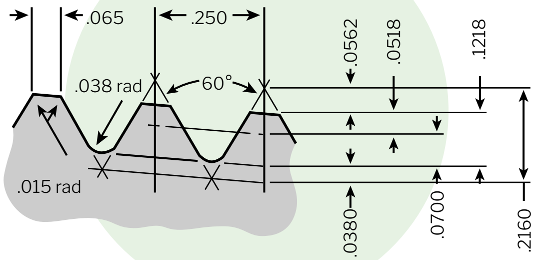
‡ *Numbered Connections (NC) may be machined only with the V-0.038 radius thread form.*

Oilfield Thread Forms

The following thread forms are used on most oilfield rotary shouldered connections. Only the 60° thread form is an API thread. The Modified V-0.065 (not shown) has been replaced and is interchangeable with the API V-0.038R.

Figure 56

V-0.038R
2-in. taper per foot (TPF) on diameter



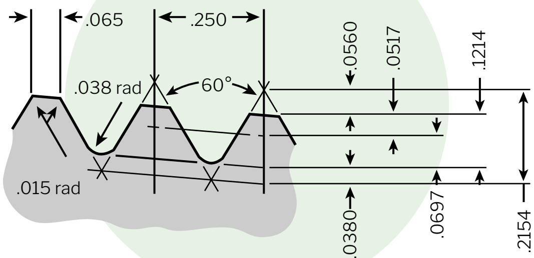
4 Threads Per Inch (TPI)

Thread profile gage must be marked: V-0.038, 4 TPI, 2-in. TPF

Used with:
API NC 23, 26, 31, 35, 38, 40, 44, 46 and 50
API IF 2⅜-, 2⅞-, 3½-, 4-, 4½-, 5½-, and 6⅝-in.
API FH 4-in.
XH 2⅞- and 3½-in.

Figure 57

V-0.038R
3-in. taper per foot (TPF) on diameter



4 Threads Per Inch (TPI)

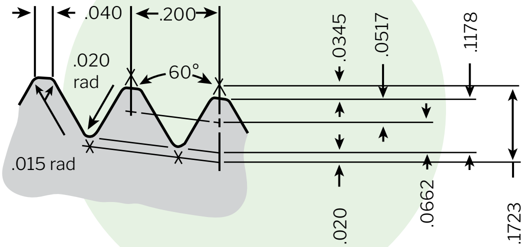
Thread profile gauge must be marked: V-0.038, 4 TPI, 3-in. TPF

Used with:
API NC 56, 61, 70 and 77

DRILL COLLARS

Figure 58

V-0.040
3-in. taper per foot (TPF) on diameter



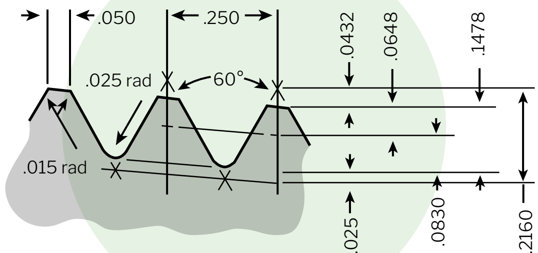
5 Threads Per Inch (TPI)

Thread profile gauge must be marked: V-0.040, 5 TPI, 3 in. TPF

Used with:
API Reg 2⅜-, 2⅞-, 3½-, and 4½-in.
API FH 3½- and 4½-in.

Figure 59

V-0.050
2-in. taper per foot (TPF) on diameter



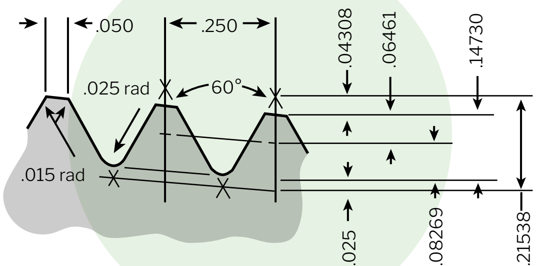
4 Threads Per Inch (TPI)

Thread profile gauge must be marked: V-0.050, 4 TPI, 2-in. TPF

Used with:
API Reg 6⅝-in.
API FH 5½- and 6⅝-in.

Figure 60

V-0.050
3-in. taper per foot (TPF) on diameter



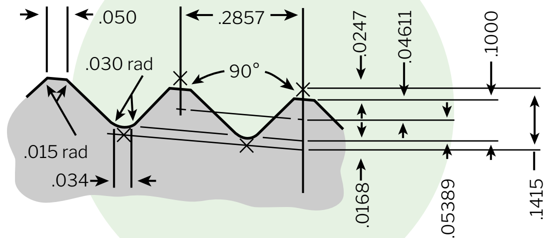
4 Threads Per Inch (TPI)

Thread profile gauge must be marked: V-0.050, 4 TPI, 3-in. TPF

Used with:
API Reg 5½-, 7⅝- and 8⅝-in.

Figure 61

H-90
2-in. taper per foot (TPF) on Diameter



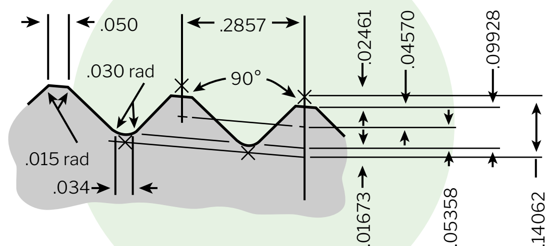
3½ Threads Per Inch (TPI)

Thread profile gauge must be marked: H 90, 3½ TPI, 2-in. TPF

Used with:
H-90 3½-, 4-, 4½-, 5½- and 6⅝-in.

Figure 62

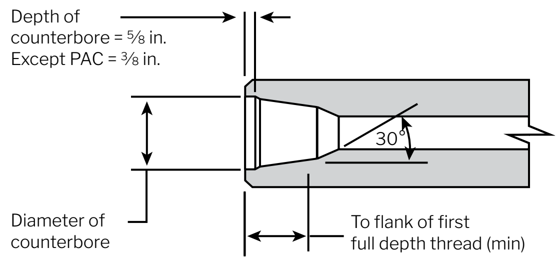
H-90
3-in. taper per foot (TPF) on diameter



3½ Threads Per Inch (TPI)

Thread profile gauge must be marked: H 90, 3½ TPI, 3-in. TPF

Used with:
H 90 7-, 7⅝-, and 8⅝-in.



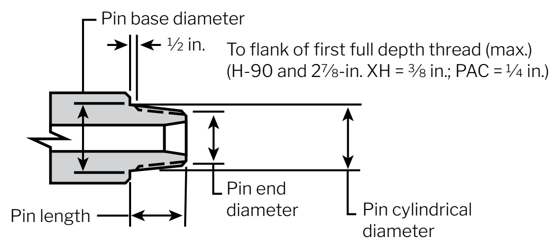
Dimensional Identification of Box Connections
(Not for Machining Purposes)

Connection Size, in.	Threads Per Inch	Taper Per Inch	Full Thread Depth, in.	Diameter of the Counterbore, in.
2 3/8 PAC	4	1 1/2	2 1/2	2 13/32
2 7/8 PAC	4	1 1/2	2 1/2	2 19/32
NC 23	4	2	3 1/8	2 5/8
2 3/8 Reg	5	3	3 1/8	2 11/16
†2 3/8 IF	4	2	3 1/8	2 15/16
2 7/8 Reg	5	3	3 5/8	3 1/16
†2 7/8 XH, EH	4	2	4 1/8	3 23/64
†2 7/8 IF	4	2	3 5/8	3 29/64
3 1/2 Reg	5	3	3 7/8	3 9/16
NC 35	4	2	3 7/8	3 13/16
3 1/2 XH, EH	4	2	3 5/8	3 7/8
3 1/2 FH	5	3	3 7/8	4 3/64
†3 1/2 IF	4	2	4 1/8	4 5/64
3 1/2 H-90	3 1/2	2	4 1/8	4 3/16
†4 FH	4	2	4 5/8	4 11/32
4 H-90	3 1/2	2	4 3/8	4 9/16
NC 44	4	2	4 5/8	4 11/16
†4 1/2 Reg	5	3	4 3/8	4 11/16
4 1/2 FH	5	3	4 1/8	4 7/8
4 1/2 H-90	3 1/2	2	4 5/8	4 57/64
†4 1/2 XH, EH	4	2	4 5/8	4 29/32
5 H-90	3 1/2	2	4 7/8	5 11/64
†4 1/2 IF	4	2	4 5/8	5 5/16
5 1/2 H-90	3 1/2	2	4 7/8	5 7/16
5 1/2 Reg	4	3	4 7/8	5 37/64
5 1/2 FH	4	2	5 1/8	5 29/32
NC 56	4	3	5 1/8	5 15/16
6 5/8 Reg	4	2	5 1/8	6 1/16
†6 5/8 H-90	3 1/2	2	5 1/8	6 1/16
5 1/2 IF	4	2	5 1/8	6 29/64
NC 61	4	3	5 5/8	6 1/2
7 H-90	3 1/2	3	5 5/8	6 9/16
6 5/8 FH	4	2	5 1/8	6 27/32
†7 5/8 Reg	4	3	5 3/8	7 3/32
NC 70	4	3	6 1/8	7 3/8
7 5/8 H-90	3 1/2	3	6 1/4	7 29/64
6 5/8 IF	4	2	5 1/8	7 33/64
8 5/8 Reg	4	3	5 1/2	8 3/64
NC 77	4	3	6 5/8	8 1/16
8 5/8 H-90	3 1/2	3	6 3/4	8 21/64

Dimensional Identification for Low Torque Modification

7 H-90	3 1/2	3	5 5/8	‡7 1/8
7 5/8 Reg	4	3	5 3/8	‡7 3/4
8 5/8 Reg	4	3	5 1/2	‡9
7 5/8 Reg	3 1/2	3	6 1/4	‡8
8 5/8 Reg	3 1/2	3	6 3/4	‡9 3/8

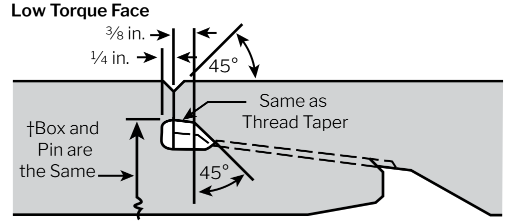
†See page 100 for interchangeable connections.



Dimensional Identification of Pin Connections
(Not for Machining Purposes)

Connection Size, in.	Threads Per Inch	Taper Per Inch	Pin Length, in.	Pin End Diameter, in.	Pin Cyl. Diameter, in.	Pin Base Diameter, in.
2 3/8 PAC	4	1 1/2	2 1/4	2 5/64	2 5/16	2 3/8
2 7/8 PAC	4	1 1/2	2 1/4	2 1/4	2 31/64	2 17/32
NC 23	4	2	2 7/8	2 5/64	2 29/64	2 9/16
2 3/8 Reg	4	3	2 7/8	1 29/32	2 33/64	2 5/8
†2 3/8 IF	4	2	2 7/8	2 25/64	2 49/64	2 7/8
2 7/8 Reg	5	3	3 3/8	2 5/32	2 57/64	3
†2 7/8 XH, EH	4	2	3 7/8	2 11/16	3 7/32	3 21/64
†2 7/8 IF	4	2	3 3/8	2 53/64	3 9/32	3 25/64
3 1/2 Reg	5	3	3 5/8	2 19/32	3 25/64	3 1/2
NC 35	4	2	3 5/8	2 9/64	3 5/8	3 47/64
3 1/2 XH, EH	4	2	3 3/8	3 1/4	3 45/64	3 13/16
3 1/2 FH	5	3	3 5/8	3 3/32	3 57/64	4
†3 1/2 IF	4	2	3 7/8	3 3/8	3 29/32	4 1/64
3 1/2 H-90	3 1/2	2	3 7/8	3 31/64	3 15/16	4 1/8
†4 FH	4	2	4 1/2	3 9/16	4 11/64	4 9/32
4 H-90	3 1/2	2	4 1/8	3 13/16	4 5/16	4 1/2
NC 44	4	2	4 1/2	3 57/64	4 33/64	4 5/8
†4 1/2 Reg	5	3	4 1/8	3 19/32	4 33/64	4 5/8
4 1/2 FH	5	3	3 7/8	3 53/64	4 11/16	4 51/64
4 1/2 H-90	3 1/2	2	3 5/8	4 7/64	4 41/64	4 53/64
†4 1/2 XH,EH	4	2	4 3/8	4 7/64	4 23/32	4 53/64
5 H-90	3 1/2	2	4 5/8	4 21/64	4 59/64	5 7/64
†4 1/2 IF	4	2	4 1/2	4 33/64	5 9/64	5 1/4
5 1/2 H-90	3 1/2	2	4 5/8	4 39/64	5 3/16	5 3/8
5 1/2 Reg	4	3	4 5/8	4 23/64	5 13/32	5 33/64
5 1/2 FH	4	2	4 7/8	5 1/64	5 23/32	5 53/64
NC 56	4	3	4 7/8	4 21/64	5 23/32	5 7/8
6 5/8 Reg	4	2	4 7/8	5 11/64	5 7/8	6
†6 5/8 H-90	3 1/2	2	4 7/8	5 3/16	5 13/16	6
5 1/2 IF	4	2	4 7/8	5 37/64	6 9/32	6 25/64
NC 61	4	3	5 3/8	5 3/32	6 9/32	6 7/16
7 H-90	3 1/2	3	5 3/8	5 5/32	6 5/16	6 1/2
6 5/8 FH	4	2	4 7/8	5 15/16	6 41/64	6 3/4
†7 5/8 Reg	4	3	5 1/8	5 23/32	6 57/64	7
NC 70	4	3	5 7/8	5 27/32	7 5/32	7 5/16
7 5/8 H-90	3 1/2	3	6	5 57/64	7 13/64	7 25/64
6 5/8 IF	4	2	4 7/8	6 41/64	7 11/32	7 29/64
8 5/8 Reg	4	3	5 1/4	6 41/64	7 27/32	7 61/64
NC 77	4	3	6 3/8	6 13/32	7 27/32	8
8 5/8 H-90	3 1/2	3	6 1/2	6 41/64	8 5/64	8 17/64

Low Torque Face



†See page 100 for interchangeable connections.
‡See page 69 for low torque face details.

Material and Welding Precautions for Downhole Tools

Generally, the materials used in the manufacture of downhole tools (stabilizers, vibration dampeners, reamers, subs, drill collars, kellys and tool joints) are American Iron and Steel Institute (AISI) 4137, 4140 or 4145. These materials are purchased by DRILCO with a specific metallurgical chemistry to assure that they will have the carbon content necessary to be heat treated to desired hardness and mechanical properties for each product.

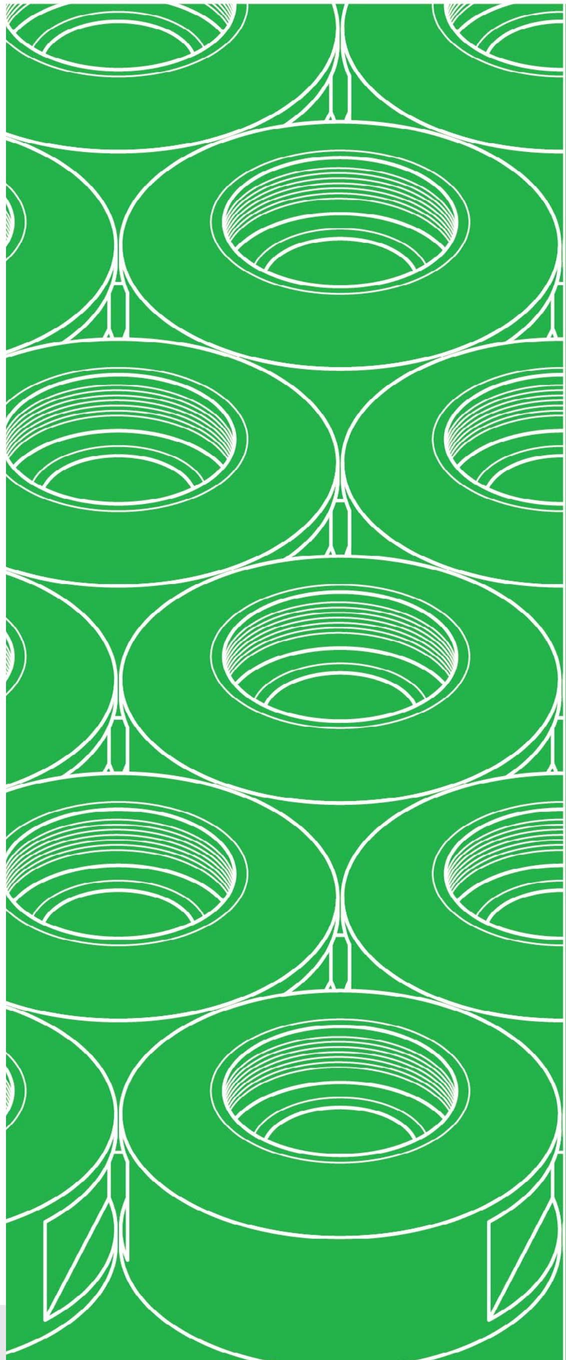
By carefully holding the chemistry and in-house heat treatment of these materials to a DRILCO specification suitable for each product or product component, strength levels are assured to minimize swollen boxes and stretched pins, provide prolonged fatigue life, retard crack propagation rates, and support tensile loads.

All of the above mentioned products are manufactured by DRILCO using these specific materials heat treated to a specific hardness to attain the desired mechanical properties of the material. This means these products cannot be repair welded in the field without changing the metallurgical properties in the heat-affected-zone of the welded area. Any metallurgical change induced by welding in the field will negate the benefits of using the specific materials and specific in-house heat treatment procedures described in the paragraph above. Special preheat procedures can be used to prevent cracking while welding. Special post-heat procedures can be used to recondition sections where welding has been performed; but, it should be emphasized that DRILCO does not recommend field repair welding. DRILCO only recommends repair welding to recondition products if they are returned to the DRILCO factory or DRILCO qualified machine shop where DRILCO welding procedures can be used to control mechanical properties and maintain product quality to make sure mechanical integrity is maintained.

SECTION FIVE

5

HEVI-WATE DRILLPIPE



HEVI-WATE DRILLPIPE

HEVI-WATE DRILLPIPE

DRILCO Hevi-Wate* drillpipe is an intermediate-weight drillstring member. It consists of heavy-wall tubes attached to special extra-length tool joints. These products have drillpipe dimensions for ease of handling. The weight and construction of Hevi-Wate drillpipe allows it to be run in compression like drill collars in highly deviated and horizontal wells as well as small diameter holes.

Although special lengths are available, the pipe is normally furnished in 30½ ft (9.3 m) lengths in six sizes from 3½- to 6⅝-in. (88.9- to 168.3-mm) OD. One outstanding feature is the integral center wear pad which protects the tube from abrasive wear. This wear pad acts as a stabilizer and is a factor in the overall stiffness and rigidity of one or more joints of Hevi-Wate drillpipe.

An example of Hevi-Wate drillpipe as an intermediate-weight drillstring member follows:

Example:
An approximate weight of 4½-in. OD drillpipe is 16.60 lb/ft; 4½-in. Hevi-Wate drillpipe weighs approximately 41 lb/ft. As another comparison, 6½-in. OD x 2¼-in. ID drill collars weigh 100 lbm/ft.

Example:
An approximate weight of 114.3-mm OD drillpipe is 24.7 kg/m; 114.3-mm Hevi-Wate drillpipe weighs approximately 61.1 kg/m. As another comparison, 165.1-mm OD x 57.2-mm ID drill collars weigh 148.8 kg/m.

When a number of drill collars are used in directional drilling, they produce a great amount of contact area with the low side of the borehole. As the collars are rotated, this high friction contact with the hole wall causes the collars to climb the side of the wall. Many in the drilling industry feel this rotation promotes a climbing action of the bottom collar and causes the bit to turn the hole direction to the right resulting in unplanned hole deviation.

Hevi-Wate drillpipe provides stability and much less wall contact. This results of this stability allows the directional driller to lock-in and better control both hole angle and direction.

Using Hevi-Wate Drillpipe for Bit Weight on Small Rigs

Using Hevi-Wate drillpipe for bit weight, allows the string to be run in compression to reduce the hook load of the drillstring which makes it ideal for smaller rigs drilling deeper holes. In shallow drilling areas, where regular drillpipe is run in compression, the more rigid Hevi-Wate drillpipe allows more bit weight to be run with less likelihood of fatigue damage.

Hevi-Wate drillpipe should not be used for bit weight in vertical holes larger than those listed below:

- 5-in. Hevi-Wate pipe — maximum vertical hole 101/16-in.
- 4½-in. Hevi-Wate pipe — maximum vertical hole 91/16-in.
- 4-in. Hevi-Wate pipe — maximum vertical hole 81/8-in.
- 3½-in. Hevi-Wate pipe — maximum vertical hole 7-in.

The ease in handling saves both rig time and trip time (Figs. 63 and 64). A long string of Hevi-Wate drillpipe helps eliminate many of the problems associated with using drill collars on smaller rigs.

Figure 63

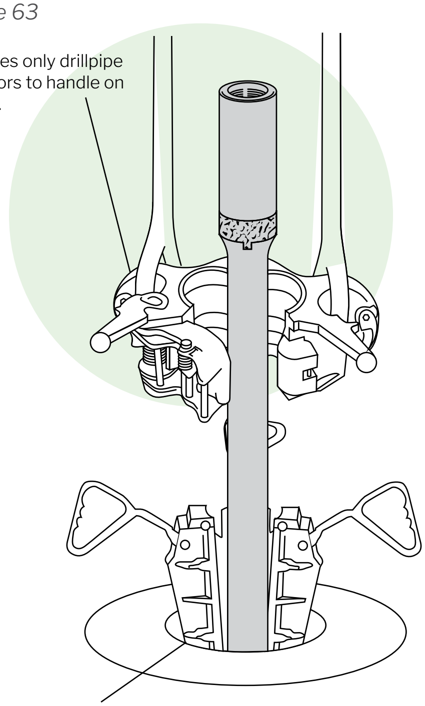
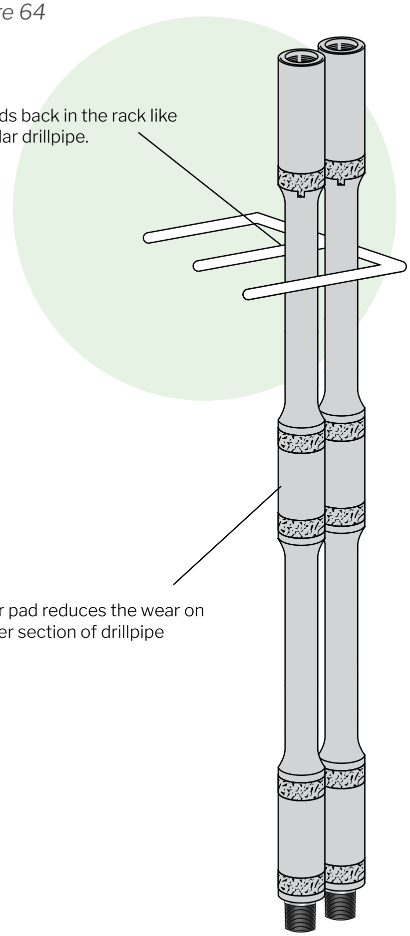


Figure 64



Using Hevi-Wate Drillpipe in the Transition Zone Between the Drill Collars and the Drillpipe

Many drillpipe failures in the drillstring occur due to fatigue damage previously accumulated when the failed joint of pipe was run directly above the drill collars. This accelerated fatigue damage is attributed to the bending stress concentration in the limber drillpipe rotating next to the stiff drill collars.

Two factors that cause extreme bending stress concentration in the bottom joint of drillpipe are:

1. Cyclic torsional whipping that moves down through the rotating drillpipe into the stiff drill collars.
2. Side to side movement, as well as the vertical bounce and vibrations of the drill collars, that are transmitted up to the bottom joint of drillpipe.

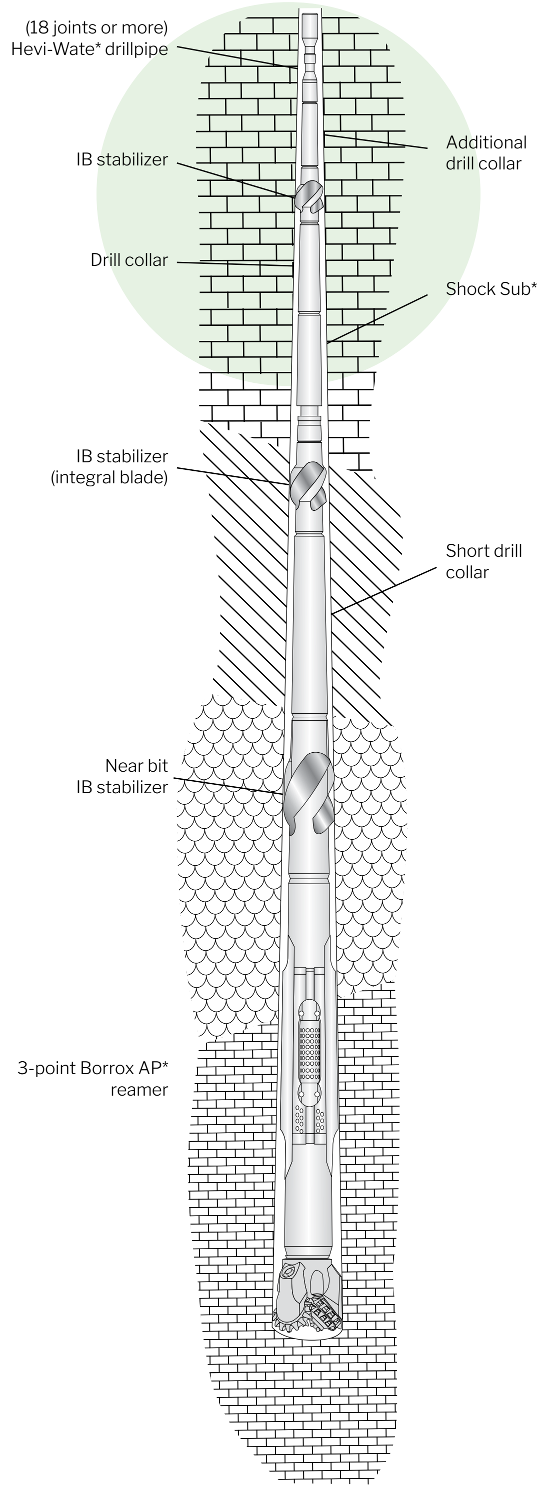
When drillpipe is subjected to compressive buckling these stress concentrations are much more severe. Many drillers periodically move the bottom joint of drillpipe to a location higher up in the drillpipe string. Moving these joints to other drillstring locations does not remove the cumulative fatigue damage that has been done, and may or may not prolong ultimate-time-to-failure.

Hevi-Wate drillpipe is an intermediate-weight drillstring member, with a tube wall approximately 1-in. (25.4-mm) thick. This compares to approximately ⅜-in. (9.5-mm) wall thickness for regular drillpipe and approximately 2-in. (50.8-mm) wall thickness for drill collars. Hevi-Wate drillpipe provides a graduated change in stiffness between the limber drillpipe above the Hevi-Wate joint(s) and the rigid drill collars below. This graduated change in stiffness reduces the likelihood of drillpipe fatigue failures when Hevi-Wate drillpipe is run in the critical transition zone of destruction. Performance records show that running Hevi-Wate drillpipe above the drill collars definitely reduces drillpipe fatigue failure. Hevi-Wate drillpipe's heavy-wall design, long tool joints and long center upset section resist the high-stress concentration and center body OD wear which is known to cause failures in regular drillpipe. Because of its construction, Hevi-Wate drillpipe can be inspected using the same procedure used to detect and help prevent drill collar failures.

The number of joints of Hevi-Wate pipe that should be run in the transition zone is important. Based on successful field experience, a minimum of eighteen (18) to twenty one (21) joints of Hevi-Wate drillpipe are recommended between the drill collars and the regular drillpipe in vertical holes. Thirty (30) or more joints are commonly used in directional holes.

HEVI-WATE DRILLPIPE

Figure 65



HEVI-WATE DRILLPIPE

Using Hevi-Wate Drillpipe in Directional Drilling

Excessive drill collar connection failure rates result from the drillstring collars bending as they rotate through doglegs and hole angle changes.

Drill collars lay to the low side of high-angle holes which can cause these results:

- Increased rotary torque
- Increased possibility of differential sticking
- Increased vertical drag
- Excessive wall friction which creates rolling action and affects directional control

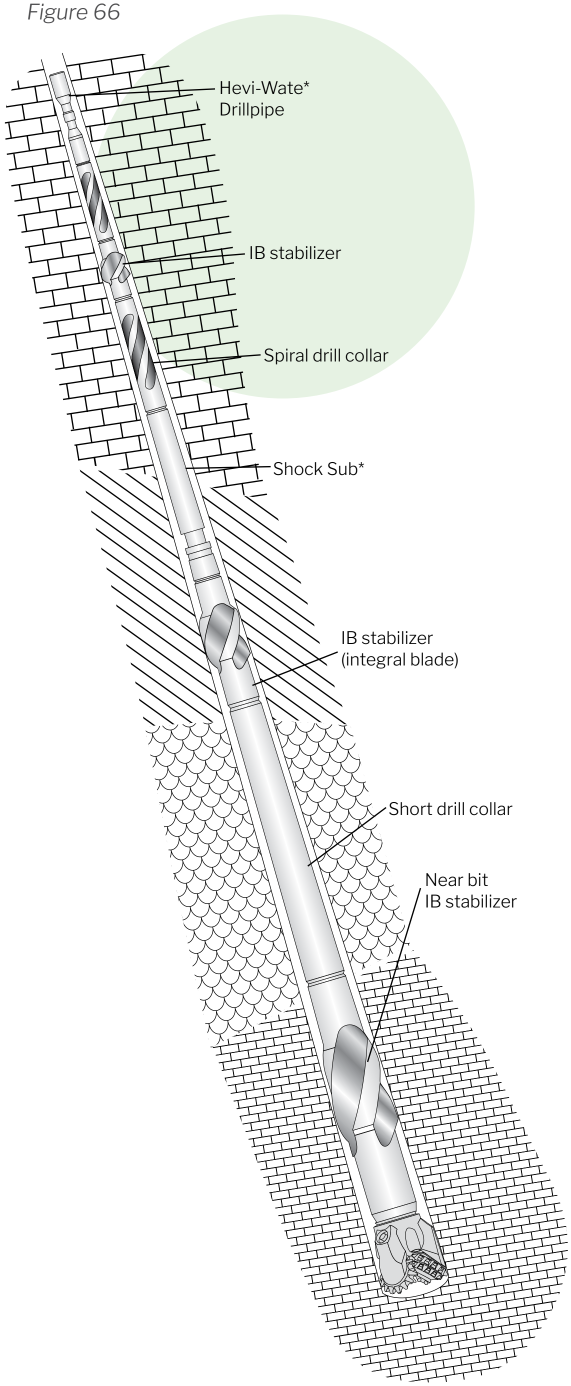
Rotating large, stiff collars through doglegs, developed in directional drilling, can cause very high-rotating torque and excessive bending loads at the threaded connections.

Hevi-Wate drillpipe bends primarily in the tube. This reduces the likelihood of tool joint fatigue failures occurring in the Hevi-Wate drillpipe as it rotates through doglegs and hole angle changes.

The Hevi-Wate drillpipe design offers less wall contact area between the pipe and hole wall which yields the following results:

- Less rotary torque
- Less chance of differential sticking
- Less vertical drag
- Better directional control

Figure 66



Capacity and Displacement Table — Hevi-Wate Drillpipe

Capacity — The volume of fluid necessary to fill the ID of the Hevi-Wate drillpipe.

Displacement — The volume of fluid displaced by the Hevi-Wate drillpipe run in open ended (metal displacement only).

Nominal Size, in.	Capacity				Displacement			
	Gal per Joint†	bbl per Joint†	Gal per 100 ft	bbl per 100 ft	Gal per Joint†	bbl per Joint†	Gal per 100 ft	bbl per 100 ft
3 ½ ‡	6.36	.151	21.2	.505	10.44	.248	34.78	.828
4	8.21	.195	27.4	.652	13.40	.319	44.66	1.063
4 ½	9.48	.226	31.6	.753	18.34	.437	61.12	1.455
5	11.23	.267	37.5	.892	22.46	.535	74.87	1.783
5 ½	14.26	.340	47.5	1.132	25.92	.617	86.41	2.057
6 ⅝	25.01	.596	83.4	1.985	32.17	.766	107.24	2.553

†Capacity and displacement per joint numbers are based on 30 ft shoulder to shoulder joints.
‡With 2¼ in. ID.

Dimensional Data Range II

Nom. Size, in.	Tube					Mechanical Properties Tube Section	
	Nominal Tube Dimension						
	ID, in.	Wall Thick-ness, in.	Area, in.2	Center Upset, in.	Elevator Upset, in.	Tensile Strength, lbf	Torsional Yield, lbf.ft
3 ½	2 ¼	.625	5.645	4	3 ⅝	310,475	18,460
4	2 9/16	.719	7.410	4 ½	4 ⅛	407,550	27,635
4 ½	2 ¾	.875	9.965	5	4 ⅝	548,075	40,715
5	3	1.000	12.566	5 ½	5 ⅛	691,185	56,495
5 ½	3 ⅜	1.063	14.812	6	5 11/16	814,660	74,140
6 ⅝	4 ½	1.063	18.567	7 ⅛	6 ¾	1,021,185	118,845

Nom. Size, in.	Tool Joint					Approximate Weight Including Tube and Joints, lbm		Make-up Torque, lbf.ft
				Mechanical Properties				
	Connection Size, in.	OD, in.	ID, in.	Tensile Yield, lbf	Torsional Yield, lbf.ft	Wt/ft	Wt/Jt	
3 ½	NC 38 (3 ½ IF)	4 ¾	2 ⅜	675,045	17,575	23.4	721	10,000
4	NC 40 (4 FH)	5 ¼	2 11/16	711,475	23,525	29.9	920	13,300
4 ½	NC 46 (4 IF)	6 ¼	2 ⅞	1,024,500	38,800	41.1	1,265	21,800
5	NC 50 (4 ½ IF)	6 ⅝	3 1/16	1,266,000	51,375	50.1	1,543	29,200
5 ½	5 ½ FH	7	3 ½	1,349,365	53,080	57.8	1,770	32,800
6 ⅝	6 ⅝ FH	8	4 ⅝	1,490,495	73,215	71.3	2,193	45,800

Dimensional Data Range III

Nom. Size, in.	Tube					Mechanical Properties Tube Section	
	Nominal Tube Dimension						
	ID, in.	Wall Thick-ness, in.	Area, in.2	Center Upset, in.	Elevator Upset, in.	Tensile Strength, lbf	Torsional Yield, lbf.ft
4 ½	2 ¾	0.875	9.965	5	4 ⅝	548,075	40,715
5	3	1.000	12.566	5 ½	5 ⅛	691,185	56,495

Nom. Size, in.	Tool Joint					Approximate Weight Including Tube and Joints, lbm		Make-up Torque, lbf.ft
				Mechanical Properties				
	Connection Size, in.	OD, in.	ID, in.	Tensile Yield, lbf	Torsional Yield, lbf.ft	Wt/ft	Wt/Jt	
4 ½	NC 46 (4 IF)	6 ¼	2 ⅞	1,024,500	38,800	41.1	1,265	21,800
5	NC 50 (4 ½ IF)	6 ⅝	3 1/16	1,266,000	51,375	48.5	2,130	29,200

Tapered Drillstrings

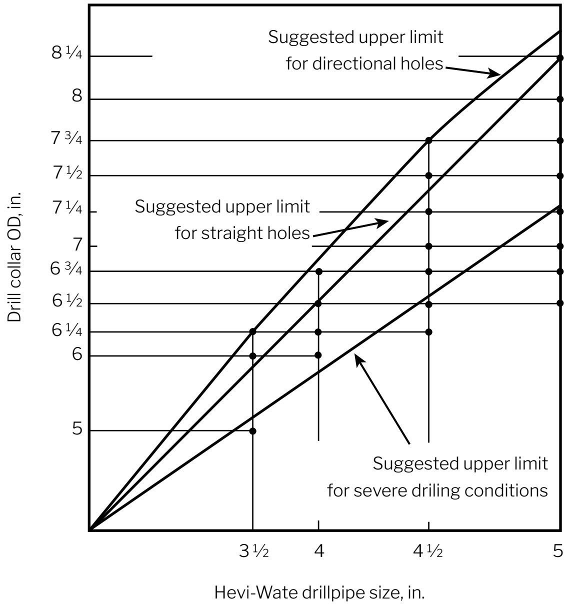
The ratios of I/C or section moduli between drill collars and Hevi-Wate drillpipe or drillpipe should be considered to prevent fatigue damage to this equipment. Experience has indicated that the equipment performs properly when this ratio is less than 5.5. Tapered drill collar strings are often necessary to maintain an acceptable ratio.

The chart on the next page is based on maintaining an acceptable I/C ratio between Hevi-Wate drillpipe and the drill collars directly below.

Example of chart use for 4½-in. (114.3-mm) Hevi-Wate drillpipe:

1. For directional holes
   a. Enter the chart from the bottom at 4½-in. (114.3-mm) Hevi-Wate drillpipe and proceed upward to the suggested upper limit for directional holes curve. Read to the left for the maximum drill collar size.
   b. Suggested maximum drill collar size equals 7¾-in. (196.9-mm) OD times the standard bore.
2. For straight holes
   a. Enter the chart from the bottom at 4½-in. (114.3-mm) Hevi-Wate drillpipe and proceed upward to the suggested upper limit for straight holes curve. Read to the left for the maximum drill collar size.

b. Suggested maximum drill collar size equals 7¼-in. (184.2-mm) OD times the standard bore.



3. For Severe Drilling Conditions (Corrosive Environment and/or Hard Formations)

   a. Enter the chart from the bottom at 4½-in. (114.3-mm) Hevi-Wate drillpipe and proceed upward to the suggested upper limit for severe conditions curve. Read to the left for the maximum drill collar size.

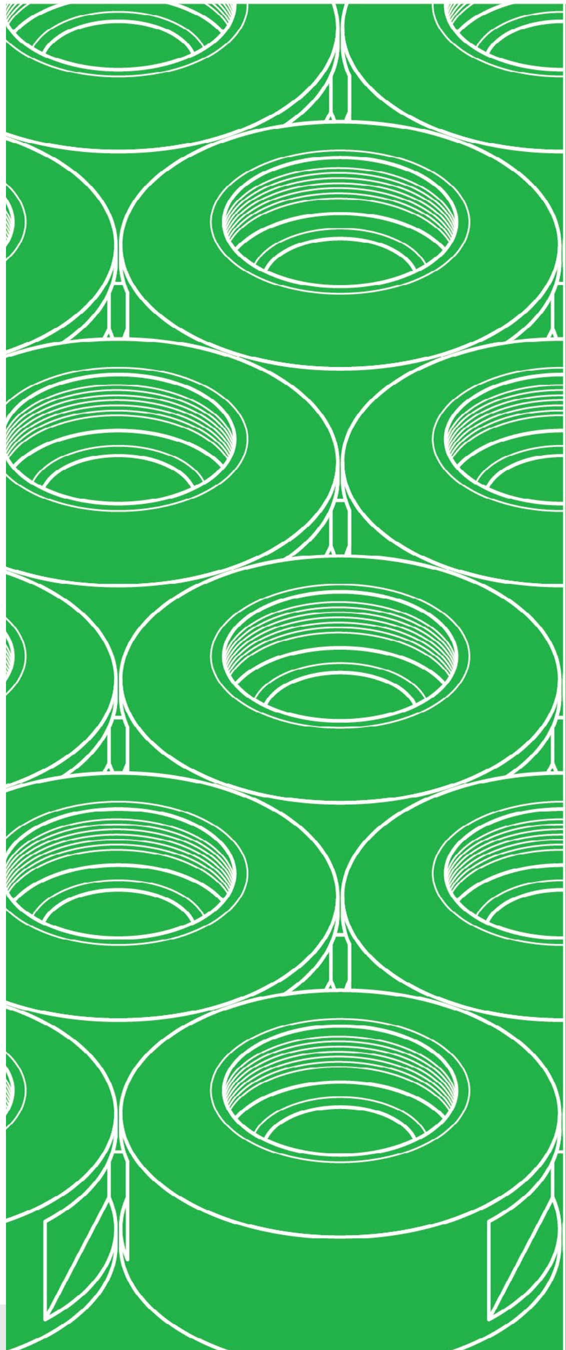
   b. Suggested maximum drill collar size equals 6½-in. (165.1-mm) OD times the standard bore.

Note: Caution should be exercised to not select a drill collar OD above the suggested upper limits for each condition. Fatigue failures are more likely if these limits are exceeded. If drill collars larger than the maximum suggested size are to be used, run at least three drill collars of the maximum suggested size (or smaller) between the larger drill collars and the Hevi-Wate drillpipe.

SECTION SIX

TOOL JOINTS

6



TOOL JOINTS

TOOL JOINTS

One of the primary purposes of drillpipe is to transmit drilling torque from the rotary table drive bushing and kelly or topdrive unit to the drilling bit at the bottom of the hole. It also provides a means for fluid to be circulated for lubricating and cooling the bit and remove the drill cuttings from the wellbore in addition to controlling the well when pressured zones are encountered.

Drillpipe connections require different treatment than drill collar connections. Drillpipe tool joints are much stiffer and stronger than the tube and seldom experience bending fatigue damage in the connection. Consequently, tool joint connections are normally selected based on torsional strength of the pin connection and tube and not on bending strength ratios as in drill collar connections.

Drill collar connections differ in that they are a sacrificial element and can never be made as strong as the drill collar body. Drill collar joint repair is also different. A drill collar connection can be renewed by cutting off the old connection and completely machining a new one; whereas a drillpipe connection can only be reworked by chasing the threads and refacing the shoulder because of its short length. The most common damage occurring to drillpipe tool joints is caused by leaking fluid, careless handling, thread wear or galling, and swelled boxes is due to outside diameter wear.

Like drill collars, the break-in of new drillpipe tool joints is extremely important for long life. Newly machined surfaces are more susceptible to galling until they become work hardened. Therefore, the connections should be chemically etched by a gall-resistant coating (see page 67) to hold the thread compound and protect the newly machined surfaces on the initial makeup. Extra care is essential to ensure long and trouble-free service. Thread protectors should be used while drillpipe is being picked up, laid down, moved or stored.

Make sure all threads and shoulders are thoroughly cleaned of any foreign material or protective coating and inspect for damage before the first makeup. If kerosene, diesel or other liquid is used, allow sufficient drying time before applying thread compound to the connections. When applying thread compound, be sure to cover thoroughly the entire surface of the threads and shoulders of both pin and box connections. It is preferable to use a good

TOOL JOINTS

grade of thread compound recommended by API or the thread manufacturer if proprietary tool joints are being used. This compound should contain no more than 0.3% sulfur. *(A thread compound containing 40 to 60% by weight of finely powdered metallic zinc is recommended in API RP 7G.)*

Proper initial makeup is probably the most important factor effecting the life of the tool joint connections. DRILCO recommends the following:

1. Proper makeup torque is determined by the connection type, size, OD and ID. This data is found in the torque tables on pages 134 to 141 of this manual.
2. Makeup connections slowly, preferably using chain tongs. (High-speed kelly spinners or the spinning chain used on initial makeup can cause galling of the threads.)
3. Makeup the joints to the predetermined torque using a properly working torque gauge to measure the required line pull (see page 41).
4. Stagger breaks on each trip so that each connection can be checked, thread compound re-applied and made up every second or third trip, depending on the length of drillpipe and size of rig.

A new string of drillpipe deserves good surface handling equipment and tools. Check the slips and master bushings before damage occurs to the tube, see the International Association of Drilling Contractors (IADC) Drilling Manual for correct measurement.

Do not stop the downward movement of the drillstring with the slips. This can cause crushing or necking down of the drillpipe tube. The drillpipe can also be damaged by allowing the slips to ride the pipe on trips out of the hole.

Good rig practices will help eliminate time consuming trips in the future, looking for washouts or fishing for drillpipe lost in the hole. For more information refer to the latest edition of the IADC Drilling Manual.

Recommended Practice for Marking on Tool Joints for Identification of Drillstring Components

Company, Month Welded, Year Welded, Pipe Manufacturer and Drillpipe Grade Symbols to be Stencilled at Base of Pin. Sample Markings:

1	2	3	4	5
D	9	99	V	E

1 — Company

2 — Month welded
(9 = September)

3 — Year welded
(99 = 1999, 05 = 2005)

4 — Pipe manufacturers
V = Vallourec

5 — Drillpipe grade
E = Grade E drillpipe

Month	Year
1 through 12	Last two digits of year

Pipe Mill	Symbol
Active	
Algoma	X
British Steel Seamless Tubes LTD	B
Dalmine S.P.A.	D
Falck	F
Kawasaki	H
Nippon	I
NKK	K
Mannesmann	M
Reynolds Aluminum	RA
Sumitomo	S
Siderca	SD
TAMSA	T
U.S. Steel	N
Vallourec	V
Used	U
Inactive	
Armco	A
American Seamless	AI
B & W	W
C F & I	C
J & L Steel	J
Lone Star	L
Ohio	O
Republic	R
TI	Z

Tubemuse	TU
Voest	VA
Wheeling Pittsburgh	P
Youngstown	Y

Manufacturers of Drillpipe

Company Name	Symbol
Arai Iron Works Company, Ltd.	-----
B & M Tool Company	-----
Bellino s.r.l.	-----
Drill Pipe International, LLC	-----
JINDAL SAW USA LLC	-----
NOV Grant Prideco	GP
PERFORATOR GmbH	-----
Superior Drill Pipe Manufacturing Inc	-----
Tenaris	-----
Texas Steel Conversion, Inc	TSC
VAM Drilling	V

Drillpipe Grades and Their Symbols

Grade	Symbol	Minimum Yield (psi)
D 55	D	55,000
E 75	E	75,000
X 95	X	95,000
G 105	G	105,000
S 135	S	135,000
V 150	V	150,000
Used	U	—

Note: Heavy-weight drillpipe to be stencilled at base of pin with double pipe grade code.

Bench Marks

API suggests that a bench mark be provided for the determination of the amount of material that may be removed from the tool joint shoulder if it is to be refaced. The API recommended practice not to remove more than 1⁄32 inch of material from the pin or box shoulder during any one refacing operation and not more than 1⁄16 inch cumulatively.

Note: Bench marks should not be used on pin connections with stress relief grooves.

API recognizes two (2) types of bench marks; the circle with the bar illustrated in Figures 67a/67b and 68a/68b and the 360° mark.

1. The first benchmark type is a 3⁄16 inch diameter circle with a bar tangent to the circle with the bar parallel to the connection shoulder. The distance from the shoulder to the bar should be 1⁄8 inch. The bench mark should be positioned in the box counter bore and on the base of the pin as shown in Figures 67a and 68a
2. The 360° bench mark type is an additional machined counter bore around the box end and a 1⁄32 inch radius 1⁄32 inch deep around the base of the pin.

The diameter of the 360 ° bench mark in the box is the standard box counter bore diameter plus 1⁄64 inch (Fig. 67b).

The inside diameter of the 360° bench mark on the pin end equals the base pin OD plus 1⁄64 inch (Fig. 68b).

Figure 67a

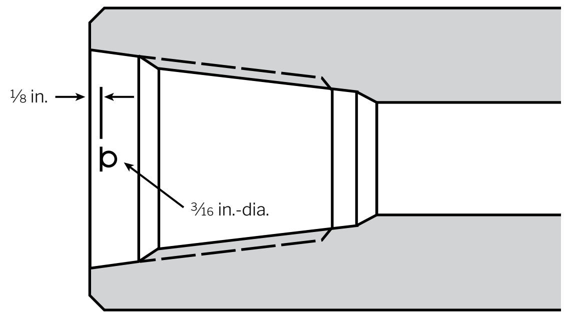


Figure 68a

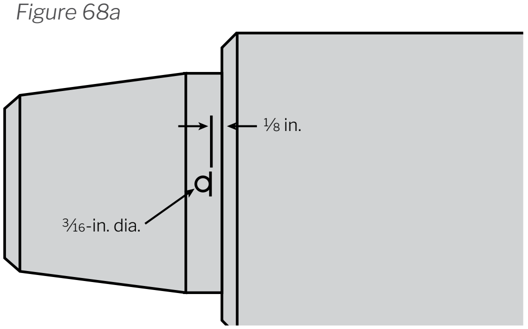


Figure 67b

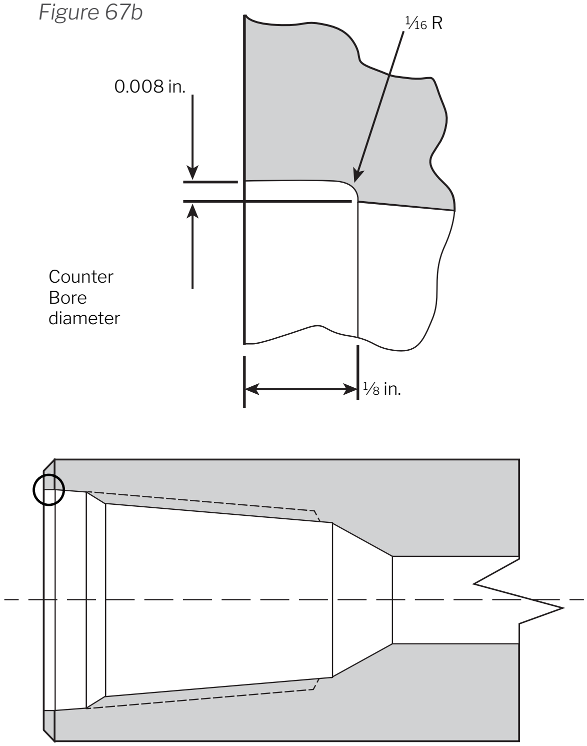
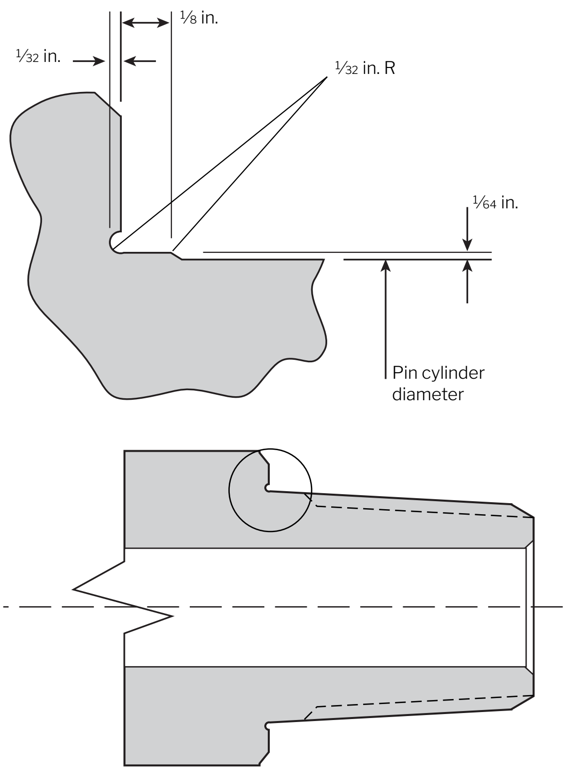


Figure 68b



Recommended Identification Groove and Marking of Drillpipe

Note:

1. Standard weight Grade E drillpipe designated by a dagger (†), see table below, in the drillpipe weight code table will have no groove or milled slot for identification. The API identification for Grade E heavy-weight drillpipe manufactured after January 1, 1995, is a milled slot only beginning ½-in. from the intersection of the 18° taper and the tool joint OD. The API identification for Grade E heavy-weight drillpipe manufactured before January 1, 1995, was a milled slot only in the center of the tong space. (ISO marking is that of the API before January 1, 1995, style.)

2. See API Recommended Practice RP 7G for depth of grooves and slots.

3. Stencil the grade code symbol and weight code number corresponding to grade and weight of pipe in milled slot of pin. Stencil with ¼-in. (6.4-mm) characters so the marking may be read with the drillpipe hanging in the elevators.

Drillpipe Weight Code

1	2	3	4
OD Size, in.	**Nominal Weight, in.**	**Wall Thickness, in.**	**Weight Code Number**
2 ⅜	4.85 6.85†	0.190 0.280	1 2
2 ⅞	6.85 10.40†	0.217 0.362	1 2
3 ½	9.50 13.30† 15.50	0.254 0.368 0.449	1 2 3
4	11.85 14.00† 15.70	0.262 0.330 0.380	1 2 3
4 ½	13.75 16.60† 20.00 22.82 24.66 25.50	0.271 0.337 0.430 0.500 0.550 0.575	1 2 3 4 5 6
5	16.25 19.50† 25.60	0.296 0.362 0.500	1 2 3
5 ½	19.20 21.90† 24.70	0.304 0.361 0.415	1 2 3
6 ⅝ 6 ⅝	25.20† 27.70	0.330 0.362	2 3

†Designates standard weight for drillpipe size.
Multiply inches by 25.4 to obtain mm.
Multiply lbf.ft by 1.356 to obtain N.m.
Multiply lbf.ft by 0.1383 to obtain kg.m.

Figure 69

Standard Weight Grade E75 Drillpipe

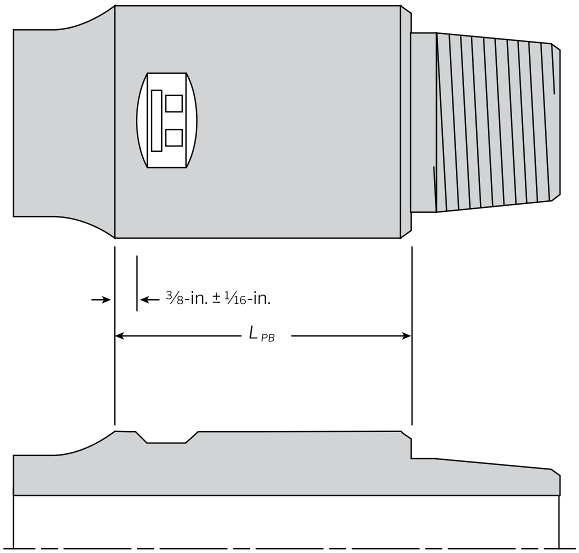
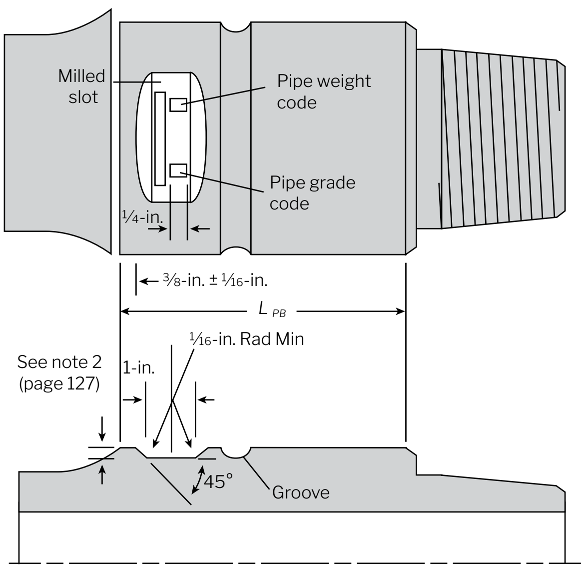


Figure 70

Standard Weight High Strength Drillpipe



L_PB = Pin tong space length (see API Spec. 7).

Figure 71

Heavy Weight Grade E75 Drillpipe

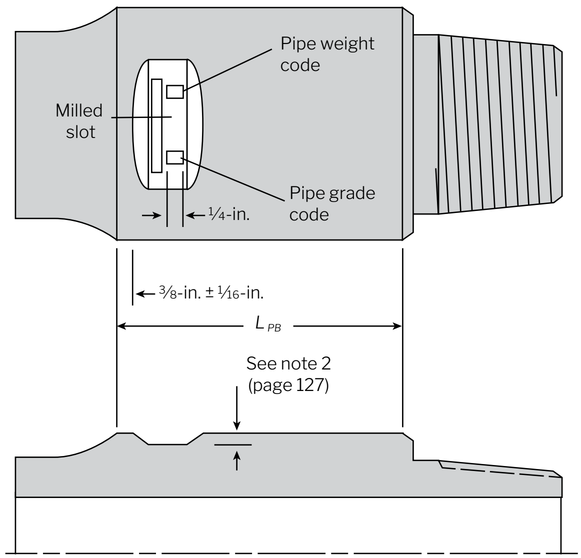
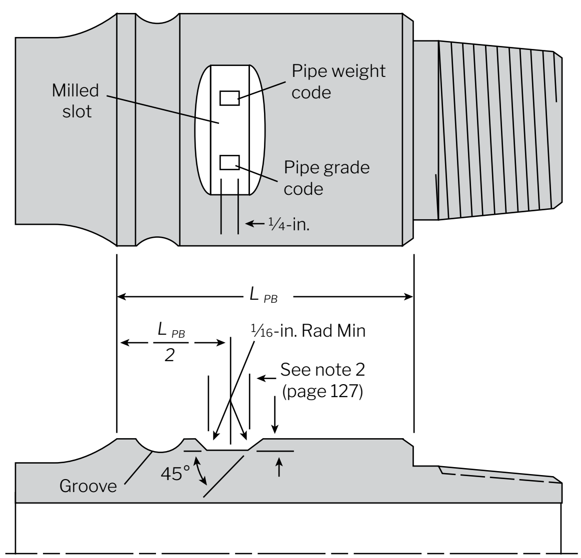


Figure 72

Heavy-Weight High-Strength Drillpipe
API Before January 1, 1995



L_PB = Pin tong space length (see API Spec. 7).

Figure 73

Heavy-Weight Grade E Drillpipe
API Before January 1, 1995

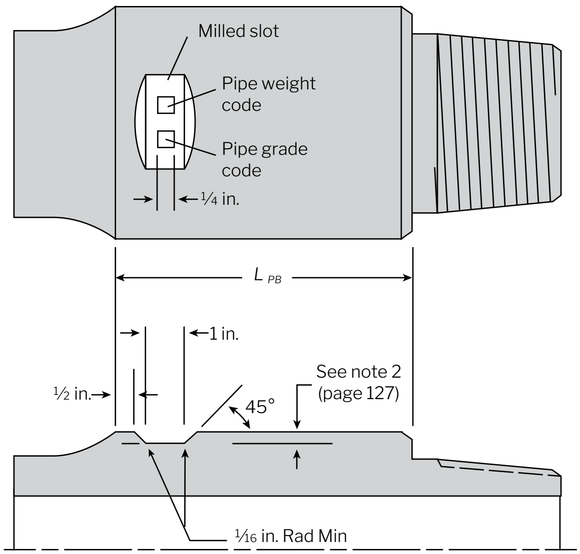


Figure 74

Standard Weight Grade X Drillpipe
API Before January 1, 1995

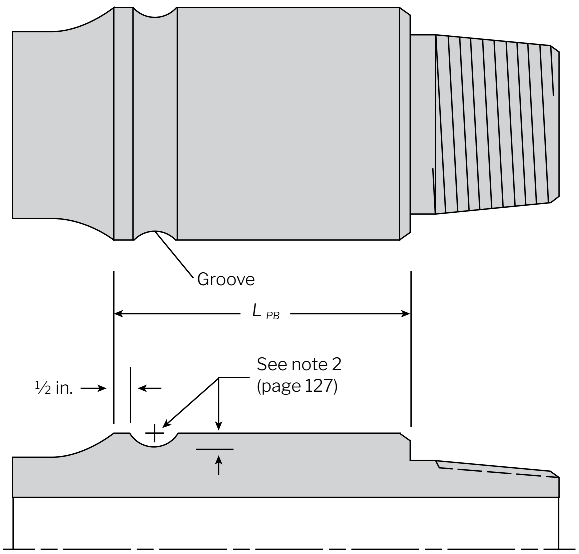


Figure 75

Heavy-Weight Grade X Drillpipe
API Before January 1, 1995

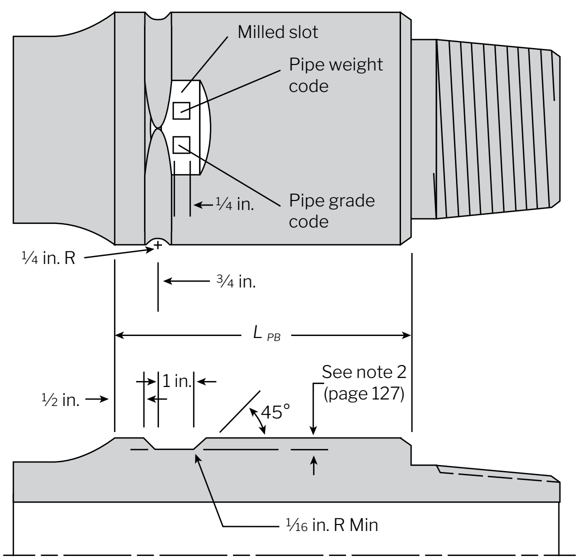


Figure 76

Standard Weight Grade G Drillpipe
API Before January 1, 1995

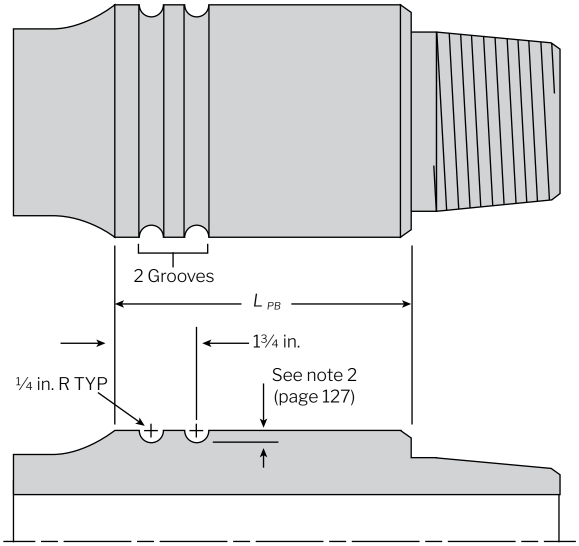


Figure 77

Heavy Weight Grade G Drillpipe
API Before January 1, 1995

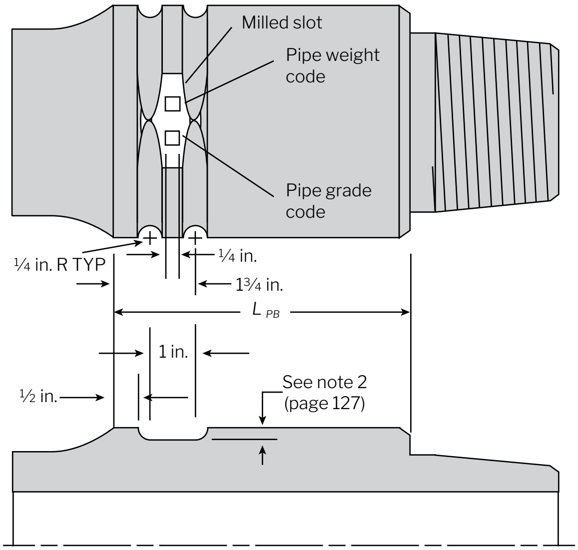


Figure 78

Standard Weight Grade S Drillpipe
API Before January 1, 1995

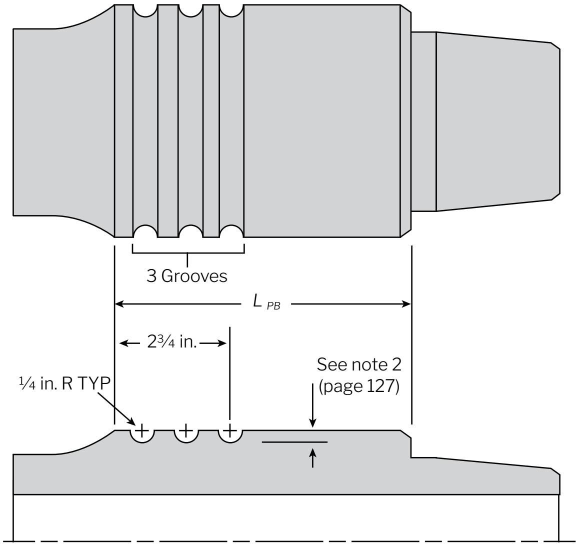
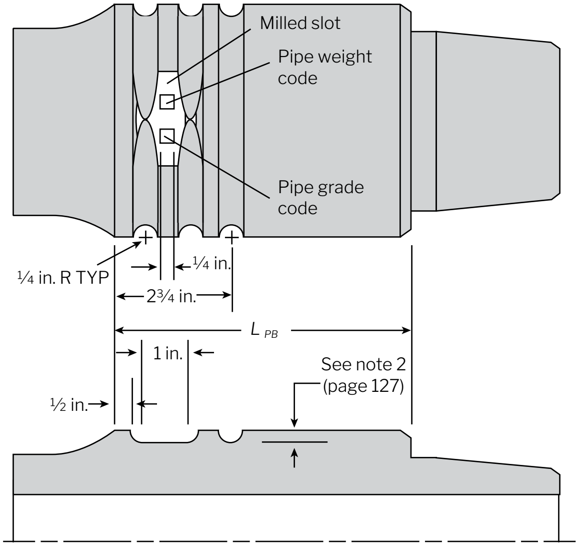


Figure 79

Heavy-Weight Grade S Drillpipe
API Before January 1, 1995



TOOL JOINTS

Torque Chart Drillpipe Tool Joint Recommended Minimums

Drillpipe Size, in.	Connection Type†, in.	New Drillpipe Box OD, in.	New Drillpipe Pin ID, in.	New Drillpipe Makeup Torque, lbm.ft
2 3/8	NC 26 (IF)	3 3/8	1 3/4	4, 125
	OH	3 1/4	1 3/4	3,783
	OH	3/8	2	2,176
	SL H-90	3 1/4	2	3,077
	WO	3 3/8	2	2,586
	PAC	2 7/8	1 3/8	2,813
2 7/8	27/8 SH (NC 26)	3 3/8	1 3/4	4,125
	OH	3 3/4	2 7/16	3,336
	OH	3 7/8	2 5/32	5,264
	SL H-90	3 7/8	2 7/16	4,579
	SL H-90	3 7/8	2 5/32	6,777
	PAC	3 1/8	1 1/2	3,443
	WO	4 1/8	2 7/16	4,318
	XH	4 1/4	1 7/8	7,969
	NC 31 (IF)	4 1/8	2 1/8	7,122
	NC 31 (IF)	4 1/8	2	7,918
	NC 31 (IF)	4 3/8	1 5/8	10,167
3 1/2	3 1/2 SH (NC 31)	4 1/8	2 1/8	7,122
	SL H-90	4 5/8	3	7,590
	SL H-90	4 5/8	2 11/16	11,142
	OH	4 3/4	3	7,218
	OH	4 3/4	2 11/16	10,387
	NC 38 WO	4 3/4	3	7,688
	NC 38 (IF)	4 3/4	2 11/16	10,864
	NC 38 (IF)	5	2 9/16	12,196
	NC 38 (IF)	5	2 7/16	13,328
	NC 38 (IF)	5	2 1/8	15,909
	NC 40 (4 FH)	5 1/4	2 9/16	16,656
	NC 40 (4 FH)	5 3/8	2 7/16	17,958
	NC 40 (4 FH)	5 1/2	2 1/4	19,766
4	SH (3 1/2 XH)	4 5/8	2 9/16	9,102
	OH	5 1/4	3 15/32	13.186
	OH	5 1/2	3 1/4	16,320
	NC 40 (4 FH)	5 1/4	2 13/16	14,092
	NC 40 (4 FH)	5 1/2	2 11/16	15,404
	NC 40 (4 FH)	5 1/2	2 7/16	18,068
	NC 40 (4 FH)	5 3/4	2 7/16	18,068
	NC 46 (WO)	6	3 7/16	17,285
	NC 46 (IF)	6	3 1/4	20,175
	NC 46 (IF)	6	3	23,538
	NC 46 (IF)	6	3	23,538
	NC 46 (IF)	6	3 1/4	20,175
	NC 46 (IF)	6	3	23,358
	NC 46 (IF)	6	2 5/8	26,983
	NC 46 (IF)	6	2 7/8	25,118
4 1/2	OH	5 7/8	3 3/4	16,346
	FH	6	3	20,868
	FH	6	2 3/4	23,843
	FH	6	2 1/2	26,559
	NC 46 (XH)	6 1/4	3 1/4	20,396
	NC 46 (XH)	6 1/4	3	23,795
	NC 46 (XH)	6 1/4	2 3/4	26,923
	NC 46 (XH)	6 1/4	2 1/2	29,778
	NC 50 (IF)	6 3/8	3 3/4	22,606
	NC 50 (IF)	6 3/8	3 3/4	22,606
	NC 50 (IF)	6 3/8	3 5/8	24,741
	NC 50 (IF)	6 3/8	3 1/2	26,804
	NC 50 (IF)	6 5/8	2 7/8	36,398
5	NC 50 (XH)	6 3/8	3 3/4	22,606
	NC 50 (XH)	6 3/8	3 1/2	26,804
	NC 50 (XH)	6 1/2	3 1/4	30,868
	NC 50 (XH)	6 1/2	3	34,191
	NC 50 (XH)	6 5/8	2 3/4	38,044
	5 1/2 FH	7	3 1/2	37,742
	5 1/2 FH	7 1/4	3 1/2	43,490
	5 1/2 FH	7 1/4	3 1/4	47,230
5 1/2	FH	7	4	33,560
	FH	7	3 3/4	37,742
	FH	7 1/4	3 1/2	43,490
	FH	7 1/2	3	52,302

Note:
†1. The use of outside diameters (OD) smaller than those listed in the table may be acceptable on Slim-Hole (SH) tool joints due to special service requirements.

Torque Chart Drillpipe Tool Joint Recommended Minimums

Used Drillpipe (Box outside diameters do not represent tool joint inspection class)					
Box OD, in.	Makeup Torque, lbm.ft	Box OD, in.	Makeup Torque, lbm.ft	Box OD, in.	Makeup Torque, lbm.ft
3 1/4	3,005	3 3/16	2,467	3 5/32	2,204
3 1/16	2,216	3 1/32	1,967	2 31/32	1,600
3	1,723	2 31/32	1,481	2 15/16	1,244
2 31/32	1,998	2 31/32	1,998	2 31/32	1,998
3 1/16	1,994	3	1,500	2 31/32	1,300
2 25/32	2,445	2 23/32	2,055	2 21/32	1,667
3 3/8	4,125	3 5/16	3,558	3 1/4	3,005
3 1/2	3,282	3 7/16	2,794	3 13/32	2,481
3 19/32	4,410	3 17/32	3,752	3 15/32	3,109
3 17/32	3,767	3 7/32	3,767	3 7/16	2,666
3 19/32	4,529	3 17/32	3,770	3 15/32	3,029
3 1/8	3,443	3 1/16	3,427	3 31/32	2,801
3 5/8	3,216	3 9/16	2,500	3 17/32	2,200
3 23/32	4,357	3 21/32	3,664	3 5/8	3,324
3 11/16	3,154	3 21/32	2,804	3 21/32	2,804
3 29/32	5,723	3 13/16	4,597	3 3/4	3,867
4 1/16	7,694	3 31/32	6,500	3 7/8	5,345
4	6,893	3 29/32	5,726	3 27/32	4,969
4 3/16	5,521	4 1/8	4,491	4 3/32	3,984
4 3/8	8,742	4 9/32	7,107	4 7/32	6,045
4 9/32	5,340	4 7/32	4,600	4 5/32	3,700
4	7,000	4 5/16	6,000	4 1/4	4,868
4 3/8	5,283	4 11/32	4,786	4 9/32	3,838
4 3/8	5,283	4 11/32	4,786	4 9/32	3,838
4 19/32	8,826	4 1/2	7,274	4 7/16	6,268
4 21/32	9,875	4 9/16	8,300	4 15/32	6.769
4 23/32	10,957	4 5/8	9,348	4 17/32	7,785
4 15/16	11,363	4 15/16	9,017	4 3/4	7,877
5	12,569	4 7/8	10.179	4 25/32	8,444
5 3/32	14,419	4 15/16	11,363	4 27/32	9,595
4 7/16	8,782	4 11/32	7,342	4 9/32	6,406
4 1/32	7,500	4 29/32	6,200	4 27/32	5,000
5 31/32	8,800	4 31/32	7,500	4 29/32	6,200
4 13/16	9,017	4 23/32	7,300	4 21/32	6,200
4 15/16	11,363	4 13/16	9,017	4 3/4	7,877
5	12,569	4 7/8	10,179	4 25/32	8,444
5	12,569	4 7/8	10,179	4 25/32	8,444
5 7/32	7,827	5 5/32	6,476	5 5/32	6,476
5 5/16	9,937	5 7/32	7,827	5 3/16	7,157
5 7/16	12,813	5 5/16	9,937	5 1/4	8,535
5 15/32	13,527	5 3/8	11,363	5 9/32	9,228
5 9/32	9,228	5 3/16	7,147	5 5/32	6,476
5 9/16	15,787	5 7/16	12,813	5 3/8	11,363
5 5/8	17,311	5 1/2	14,288	5 13/16	12,080
5 5/8	17,311	5 1/2	14,288	5 13/16	12,080
5 15/32	12,300	5 3/8	10,375	5 5/16	8,600
5 3/8	12,125	5 9/32	10,066	5 3/16	8,071
5 9/16	16,391	5 7/16	13,523	5 11/32	11,481
5 5/8	17,861	5 15/32	14,214	5 3/8	12,125
5 13/32	12,080	5 5/16	9,937	5 1/4	8,535
5 19/32	16,456	5 15/32	13,554	5 3/8	11,363
5 25/32	21,230	5 5/8	17,311	5 1/2	14,281
5 23/32	19,626	5 9/16	15,787	5 15/32	13,554
5 29/32	16,626	5 25/32	13,239	5 23/32	11,571
5 23/32	11,571	5 21/32	9,965	5 19/32	8,365
5 13/16	14,082	5 23/32	11,571	5 21/32	9,995
5 15/16	17,497	5 27/32	14,933	5 3/4	12.415
6 7/32	25,547	6 1/16	21,018	5 15/16	17,497
5 7/8	15,776	5 25/32	13,239	5 11/16	10,773
6 1/32	20,120	5 29/32	16,626	5 13/16	14,082
6 3/32	21,914	5 31/32	18,346	5 27/32	14,933
6 9/32	24,645	6 1/32	20,127	5 15/16	17,933
6 3/16	27,429	6 1/8	22,818	6	19,244
6 21/32	25,474	6 1/2	20,205	6 13/32	17,118
6 23/32	27,619	6 9/16	22,294	6 15/32	19,147
6 15/16	35,446	6 3/4	28,737	6 5/8	24,413
6 17/32	21,238	6 7/16	18,146	6 11/32	15,086
6 5/8	24,412	6 1/2	20,205	6 13/32	17,118
6 25/32	29,828	6 5/8	24,412	6 17/32	21,238
7 1/32	38,892	6 27/32	32,031	6 11/16	26,560

2. Makeup torque is based on the use of thread compound using no less than 40 to 60% by weight of finely powdered metallic zinc, applied to all threads and shoulders.

TOOL JOINTS

TurboTorque® Tool Joint Makeup Torque†

Connection Type	Box OD. in.	Pin ID. in.	Minimum MUT ft.lbf	Recommended MUT ft.lbf ‡
TurboTorque 380	4 3⁄4 4 13⁄16	2 11⁄16 2 1⁄2	18,200 21,600	25,500 30,200
TurboTorque 390	4 7⁄8	2 11⁄16	21,200	29,700
TurboTorque 420	5 1⁄4	2 15⁄16	25,700	36,000
TurboTorque 435	5 3⁄8	3 1⁄8	26,700	37,400
TurboTorque 485	6 6 1⁄8	3 9⁄16 3 1⁄4	34,100 43,000	47,700 60,200
TurboTorque 500	6 1⁄4	3 1⁄2	42,100	59,000
TurboTorque 525	6 1/2 6 5⁄8	3 7⁄8 3 9⁄16	41,300 52,000	57,900 72,800
TurboTorque 550	6 5⁄8	4 1⁄4	42,400	59,300
TurboTorque 585	7 7 1⁄8	4 1⁄2 4 5⁄16	51,800 60,200	72,500 84,200
TurboTorque 690	8 1⁄4	5 1⁄2	68,400	95,800

† Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

‡ Applies to drillpipe and heavy weight drillpipe tool joints.

TurboTorque® — Third generation double shoulder connection providing approximately 80% more torque capacity than API connections of equivalent dimensions, and approximately 30% over XT®. Not interchangeable with API connections. Primary benefits for TurboTorque connections include: it saves time, cuts costs; increases torque capacity; optimizes hydraulics; improves clearance and fishability; reduces risk of failure; and extends life of the connection itself.

TurboTorque-M® Tool Joint Makeup Torque†

Connection Type	Box OD. in.	Pin ID. in.	Minimum MUT ft.lbf	Recommended MUT ft.lbf ‡
TurboTorque 380	4 3⁄4 4 13⁄16	2 11⁄16 2 1⁄2	16,000 19,400	22,400 27,100
TurboTorque 390	4 7⁄8	2 11⁄16	18,900	26,400
TurboTorque 420	5 1⁄4	2 15⁄16	23,000	32,200
TurboTorque 435	5 3⁄8	3 1⁄8	23,800	33,400
TurboTorque 485	6 6 1⁄8	3 9⁄16 3 1⁄4	30,600 39,500	42,800 55,300
TurboTorque 500	6 1⁄4	3 1⁄2	38,400	53,700
TurboTorque 525	6 1⁄2 6 5⁄8	3 7⁄8 3 9⁄16	37,200 47,900	52,100 67,100
TurboTorque 550	6 5⁄8	4 1⁄4	37,800	52,900
TurboTorque 585	7 7 1⁄8	4 1⁄2 4 5⁄16	46,600 55,000	65,200 77,000
TurboTorque 690	8 1⁄4	5 1⁄2	63,400	76,100
TurboTorque 710	8 1⁄2	5 5⁄8	68,800	82,600

† Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

‡ Applies to drillpipe and heavy weight drillpipe tool joints.

TurboTorque-M™ with Metal-To-Metal Seal – Gas-tight pressure-rated rotary shoulder connection. The radial seal provides a pressure rating of 20,000 psi internal, and 10,000 psi external. Torque capacity is similar to that of TurboTorque connections. Not interchangeable with API connections.

uXT® Tool Joint Makeup Torque†

Connection Type	Box OD. in.	Pin ID. in.	Minimum MUT ft.lbf	Recommended MUT ft.lbf ‡
uXT24	3 1/8	1 1/2	5,100	7,200
uXT26	3 1/2	1 3/4	6,200	8,700
	3 1/2	1 1/2	8,000	11,200
	3 1/2	1 1/4	8,900	12,500
uXT29	3 3/4	2	8,200	11,400
uXT31	4 1/8	2	11,300	15,800
	4 1/8	1 7/8	12,500	17,500
	4	2	10,900	15,200
	4	2 1/8	9,900	13,900
uXT38	4 7/8	2 9/16	17,100	24,000
	4 7/8	2 7/16	19,000	26,600
	4 3/4	2 11/16	15,100	21,200
	4 3/4	2 9/16	17,100	23,900
	4 3/4	2 7/16	18,600	26,100
uXT39	4 7/8	2 9/16	20,000	28,000
	4 7/8	2 11/16	19,100	26,800
	4 7/8	2 3/4	18,600	26,100
	4 7/8	2 13/16	17,800	25,000
	5	2 7/8	16,800	23,500
	5	2 13/16	17,900	25,100
	5	2 11/16	20,100	28,100
	5	2 9/16	22,100	30,900
uXT40	5 1/4	3	20,200	28,300
	5 1/4	2 13/16	23,800	33,300
uXT43	5 3/4	2 3/4	30,700	43,000
	5 3/8	3	25,600	35,800
uXT46	6 1/4	3 1/4	38,000	53,200
uXT50	6 5/8	3 3/4	41,800	58,600
	6 5/8	3 1/2	49,100	68,800
	6 1/2	3 3/4	41,700	58,400
	6 3/8	3 3/4	40,700	57,000
	6 3/8	3 1/2	44,000	61,600
uXT54	6 3/4	4	46,900	65,700
	6 5/8	4	45,100	63,100
uXT55	6 3/8	3 5/8	65,200	91,200
	7	4	52,500	73,400
uXT57	7 1/4	3 3/4	68,900	96,400
	7 1/4	3 1/2	73,600	103,000
	7 1/4	3 1/4	76,600	107,300
	7 1/4	3 3/16	77,400	108,300
	7 1/8	3 1/4	72,100	101,000
	7	4 1/4	51,100	71,500
	7	4	57,500	80,500
	7	3 3/4	61,300	85,800
	7	3 1/2	64,700	90,500
uXT65	8	5	73,300	102,600
uXT69	8 1/2	5 1/4	90,600	126,800

† Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

‡ Applies to drillpipe and heavy weight drillpipe tool joints.

XT® is a trademark of Grant Prideco, L.P. Reference to XT® tool joint connections does not imply that DRILCO is endorsed, sponsored, affiliated or licensed by Grant Prideco, L.P. This tool joint makeup torque data is provided solely for general information purposes. DRILCO makes no warranty with respect to the completeness, reliability or accuracy of this information.

XT® Tool Joint Makeup Torque†

Connection Type	Box OD. in.	Pin ID. in.	Minimum MUT ft.lbf	Recommended MUT ft.lbf ‡
XT24	3 1/8	1 1/2	4,700	5,700
XT26	3 1/2	1 3/4	5,800	6,900
	3 1/2	1 1/2	7,400	8,900
	3 1/2	1 1/4	8,200	9,900
XT29	3 3/4	2	7,500	9,000
XT31	4 1/8	2	10,400	12,500
	4 1/8	1 7/8	11,600	13,900
	4	2	10,000	12,100
	4	2 1/8	9,200	11,000
XT38	4 7/8	2 9/16	15,800	19,000
	4 7/8	2 7/16	17,600	21,100
	4 3/4	2 11/16	13,900	16,700
	4 3/4	2 9/16	15,800	18,900
	4 3/4	2 7/16	17,200	20,600
XT39	4 7/8	2 9/16	18,500	22,200
	4 7/8	2 11/16	17,700	21,200
	4 7/8	2 3/4	17,200	20,700
	4 7/8	2 13/16	16,500	19,800
	5	2 7/8	15,500	18,600
	5	2 13/16	16,500	19,800
	5	2 11/16	18,500	22,200
	5	2 9/16	20,400	24,500
XT40	5 1/4	3	18,700	22,400
	5 1/4	2 13/16	22,000	26,400
XT43	5 3/4	2 3/4	28,300	34,000
	5 3/4	3	23,600	28,300
XT46	6 1/4	3 1/4	35,100	42,100
XT50	6 5/8	3 3/4	38,600	46,400
	6 5/8	3 1/2	45,300	54,400
	6 1/2	3 3/4	38,500	46,200
	6 3/8	3 3/4	37,600	45,100
	6 3/8	3 1/2	40,600	48,700
XT54	6 3/4	4	43,300	52,000
	6 5/8	4	41,600	49,900
XT55	7 3/8	3 5/8	60,100	72,700
	7	4	48,400	58,100
XT57	7 1/4	3 3/4	63,600	76,300
	7 1/4	3 1/2	67,900	81,500
	7 1/4	3 1/4	70,700	84,900
	7 1/4	3 3/16	71,400	85,700
	7 1/8	3 1/4	66,600	79,900
	7	4 1/4	47,200	56,600
	7	4	53,100	63,700
	7	3 3/4	56,600	67,900
	7	3 1/2	59,700	71,600
XT65	8	5	67,700	81,200
XT69	8 1/2	5 1/4	83,600	100,300

† Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

‡ Applies to drillpipe and heavy weight drillpipe tool joints.

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XT-M® Tool Joint Makeup Torque†

Connection Type	Box OD. in.	Pin ID. in.	Minimum MUT ft.lbf	Recommended MUT ft.lbf ‡
XT-M26	3 3/8	1 3/4	4,800	5,000
XT-M31	4 4 3 7/8	2 2 1/8 2 1/8		10,800 9,700 8,500
XT-M34	4 1/4	2 9/16	8,000	9,700
XT-M38	4 3/4 4 3/4	2 9/16 2 11/16	13,900 12,100	16,700 14,500
XT-M39	5 5 5 4 7/8	2 7/16 2 9/16 2 13/16 2 11/16	19,400 18,600 14,700 15,800	23,300 22,300 17,700 18,900
XT-M40	5 1/4	2 11/16	21,800	26,200
XT-M43	5 1/4 5 1/4	3 3 1/4	19,600 16,200	23,500 19,500
XT-M46	6 1/4	3	37,600	45,100
XT-M50	6 5/8 6 1/2 6 1/4 6 1/4	3 1/2 3 3/4 3 1/2 3 5/8	42,000 35,100 33,900 32,400	50,300 42,100 40,700 38,900
XT-M54	6 5/8	4	37,800	45,400
XT-M57	7 1/4 7 7 7	4 1/4 4 1/8 4 1/4 4	43,200 47,100 43,000 49,000	51,900 56,500 51,600 58,700
XT-M65	8	5	62,200	74,600
XT-M69	8 1/2	5 1/4	77,400	92,900

† Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

‡ Applies to drillpipe and heavy weight drillpipe tool joints.

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HT® Tool Joint Makeup Torque†

Connection Type	Box OD. in.	Pin ID. in.	Minimum MUT ft.lbf	Recommended Torque ft.lbf ‡
2 3/8 HTSLH90	3 1/8 3 1/8	1 15/16 1 3/4	3,800 4,700	4,600 5,600
2 7/8 HTPAC	3 1/8 3 1/8	1 1/2 1 3/8	4,300 4,900	5,100 5,900
HT26	3 5/8 3 5/8 3 5/8 3 1/2 3 3/8	1 1/2 1 3/8 1 1/4 1 1/2 1 3/4	6,600 7,300 7,600 6,000 4,400	7,900 8,700 9,200 7,300 5,200
HT31	4 1/4 4 1/8 4 1/8 4 1/8	1 3/4 2 1/8 2 1 7/8	11,700 8,300 9,500 9,900	14,000 10,000 11,300 11,900
HT38	5 5 4 3/4 4 3/4 4 3/4 4 7/8	2 9/16 2 7/16 2 11/16 2 9/16 2 7/16 2 9/16	14,800 16,500 12,600 13,400 14,200 14,700	17,700 19,800 15,200 16,100 17,000 17,700
HT40	5 1/2 5 1/4 5 1/4 5 1/8 5 1/8	2 9/16 2 13/16 2 11/16 2 11/16 2 9/16	19,700 16,000 17,900 16,800 17,600	23,700 19,200 21,500 20,100 21,100
HT46	6 1/4 6 1/4	3 1/4 3	23,800 28,900	28,500 34,600
HT50	6 5/8 6 5/8 6 5/8 6 5/8 6 1/2 6 1/4	3 3/4 3 1/2 3 1/4 3 3 1/2 3 3/4	26,700 33,100 39,000 44,400 33,000 26,400	32,000 39,700 46,800 53,300 39,600 31,600
HT55	7 1/2 7 3/8 7 1/4 7 1/4 7 1/4 7 1/4 7 1/4 7 1/8 7 1/8 7 1/8 7 1/8 7 7	3 3/16 3 3/8 4 3 3/4 3 1/2 3 1/4 3 4 3 7/8 3 1/2 3 1/4 4 3 3/4	61,500 56,700 38,900 46,300 53,200 57,500 60,000 38,800 42,500 50,800 53,500 38,600 43,900	73,800 68,000 46,700 55,600 63,900 69,000 72,000 46,500 51,100 61,000 64,200 46,300 52,700
HT65	8 1/2 8 1/2 8 1/4 8	5 4 1/4 4 13/16 5	50,400 81,500 58,400 49,800	60,500 97,800 70,100 59,800

† Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

‡ Applies to drillpipe and heavy weight drillpipe tool joints.

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uGPDS® Tool Joint Makeup Torque†

Connection Type	Box OD. in.	Pin ID. in.	Minimum MUT ft.lbf	Recommended MUT ft.lbf ‡
uGPDS26	3 3⁄8	1 3⁄4	4,700	6,600
	3 1⁄2	1 11⁄16	5,200	7,300
	3 1⁄2	1 5⁄8	6,100	8,600
uGPDS31	4 1⁄8	2	9,300	13,100
	4 1⁄8	1 7⁄8	10,500	14,700
uGPDS38	5	2 7⁄16	15,800	22,200
	5	2 9⁄16	14,000	19,600
	5	2 1⁄4	18,400	25,700
	4 7⁄8	2 9⁄16	13,900	19,500
	4 7⁄8	2 7⁄16	15,700	22,000
uGPDS40	5 1⁄2	2 7⁄16	21,900	30,600
	5 3⁄8	2 1⁄2	20,800	29,100
	5 1⁄4	2 11⁄16	17,700	24,800
	5 1⁄4	2 5⁄8	18,800	26,300
	5 1⁄4	2 9⁄16	19,800	27,700
	5 1⁄4	2 1⁄2	20,700	29,000
uGPDS46	6	3 1⁄4	23,300	32,600
	6	3 3⁄16	24,700	34,500
	6	3 1⁄8	26,100	36,500
	6	3	28,700	40,200
	6	2 15⁄16	30,000	42,000
uGPDS50	6 5⁄8	2 3⁄4	50,200	70,300
	6 5⁄8	3	45,000	62,900
	6 5⁄8	3 1⁄4	39,100	54,800
	6 1⁄2	3 1⁄4	39,000	54,600
	6 1⁄2	3 1⁄2	32,600	45,700
	6 1⁄2	3 3⁄4	25,700	36,000
uGPDS55	7 1⁄4	3 3⁄4	47,900	67,100
	7 1⁄8	3 3⁄4	47,800	66,900
	7	3 1⁄2	50,400	70,600
	7	3 3⁄4	47,100	66,000
	7	4	39,600	55,400
uGPDS65	8 1⁄4	4 3⁄4	63,600	89,100
	8 1⁄2	4 1⁄4	85,700	119,900
	8	4 7⁄8	57,400	80,400

† Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

‡ Applies to drillpipe and heavy weight drillpipe tool joints.

uGPDS® – These connections are interchangeable with their standard counterpart (uGPDS40 to GPDS40 for example). uGPDS® provides approximately 70% more torque capacity than API connections of equivalent dimensions, and approximately 25% over GPDS®.

GPDS® is a trademark of Grant Prideco, L.P. Reference to GPDS® tool joint connections does not imply that DRILCO is endorsed, sponsored, affiliated or licensed by Grant Prideco, L.P. This tool joint makeup torque data is provided solely for general information purposes. DRILCO makes no warranty with respect to the completeness, reliability or accuracy of this information.

GPDS® Tool Joint Makeup Torque†

Connection Type	Box OD. in.	Pin ID. in.	Minimum MUT ft.lbf	Recommended MUT ft.lbf ‡
GPDS26	3 3⁄8	1 3⁄4	4,300	5,200
	3 1⁄2	1 11⁄16	4,800	5,800
	3 1⁄2	1 5⁄8	5,300	6,300
GPDS31	4 1⁄8	2	8,600	10,300
	4 1⁄8	1 7⁄8	9,700	11,600
GPDS38	5	2 7⁄16	14,600	17,500
	5	2 9⁄16	12,900	15,500
	5	2 1⁄4	17,000	20,300
	4 7⁄8	2 9⁄16	12,900	15,400
	4 7⁄8	2 7⁄16	14,500	17,400
GPDS40	5 1⁄2	2 7⁄16	20,200	24,200
	5 3⁄8	2 1⁄2	19,200	23,000
	5 1⁄4	2 11⁄16	16,400	19,600
	5 1⁄4	2 5⁄8	17,300	20,800
	5 1⁄4	2 9⁄16	18,200	21,900
	5 1⁄4	2 1⁄2	19,100	23,000
GPDS46	6	3 1⁄4	21,500	25,800
	6	3 3⁄16	22,800	27,300
	6	3 1⁄8	24,000	28,900
	6	3	26,500	31,800
	6	2 15⁄16	27,700	33,200
	6	2 3⁄4	31,100	37,300
GPDS50	6 5⁄8	2 3⁄4	46,400	55,600
	6 5⁄8	3	41,500	49,800
	6 5⁄8	3 1⁄4	36,100	43,300
	6 1⁄2	3 1⁄4	36,000	43,200
	6 1⁄2	3 1⁄2	30,100	36,200
	6 1⁄2	3 3⁄4	23,800	28,500
GPDS55	7 1⁄4	3 3⁄4	44,200	53,100
	7 1⁄8	3 3⁄4	44,100	52,900
	7	3 1⁄2	46,500	55,800
	7	3 3⁄4	43,500	52,200
	7	4	36,500	43,800
GPDS65	8 1⁄4	4 3⁄4	58,700	70,400
	8 1⁄2	4 1⁄4	78,700	94,400
	8	4 7⁄8	53,000	63,600

† Normal torque range — tabulated minimum value to 10% greater. Largest diameter shown for each connection is the maximum recommended for that connection. If the connections are used on drill collars larger than the maximum shown, increase the torque values shown by 10% for a minimum value. In addition to the increased minimum torque value, it is also recommended that a fishing neck be machined to the maximum diameter shown.

‡ Applies to drillpipe and heavy weight drillpipe tool joints.

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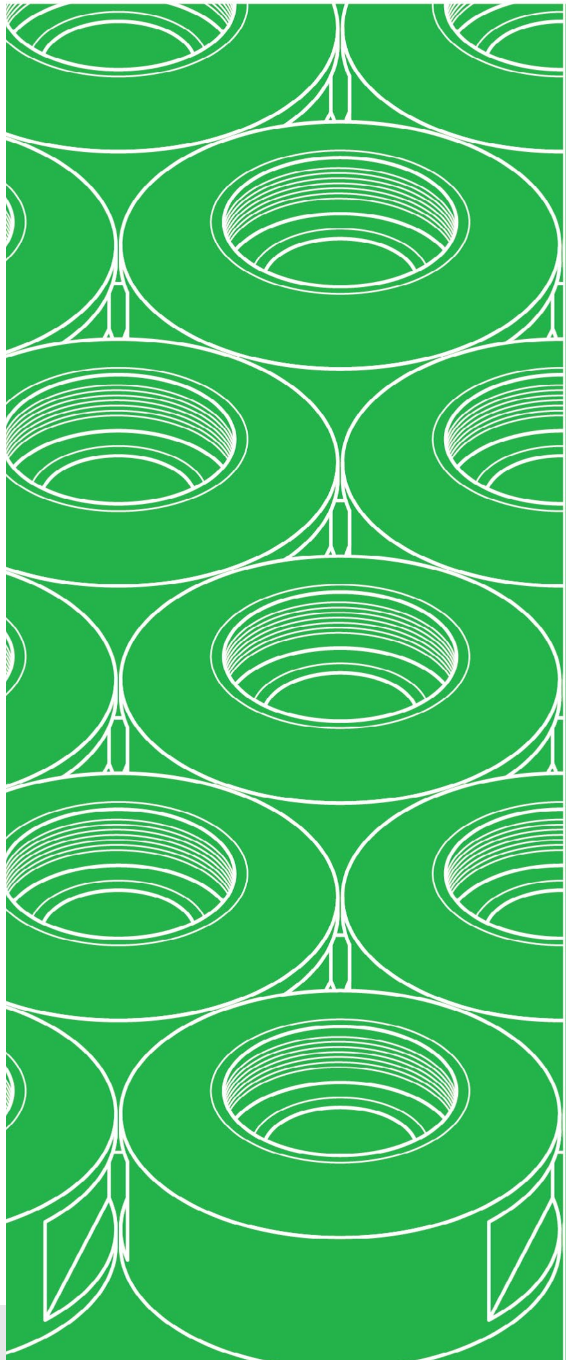
A large portion of the information found on pages 123-133 was taken directly from the IADC Drilling Manual (eleventh edition) and the API Spec. RP 7G (fifteenth edition). DRILCO extends their thanks to the IADC and API for the authorization to reprint their information.

SECTION SEVEN

KELLYS

7



KELLYS

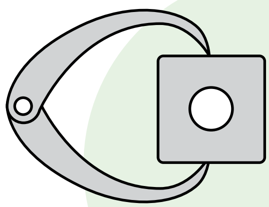
KELLYS

Kellys are manufactured with one of two basic configurations — square or hexagonal.

Kelly Sizes

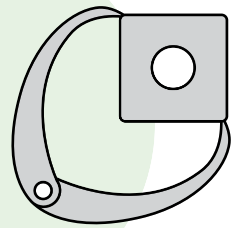
The size of a kelly is determined by the distance across the drive flats (see Figure Nos. 80 and 81).

Figure 80



Like this

Figure 81



Not like this

Kelly Lengths

API kellys are manufactured in two standard lengths: (1) 40 ft (12.2 m) overall with a 37 ft (11.3 m) working spacer

(2) 54 ft (16.5 m) overall with a 51 ft (15.5 m) working space.

End Connections Square Kellys

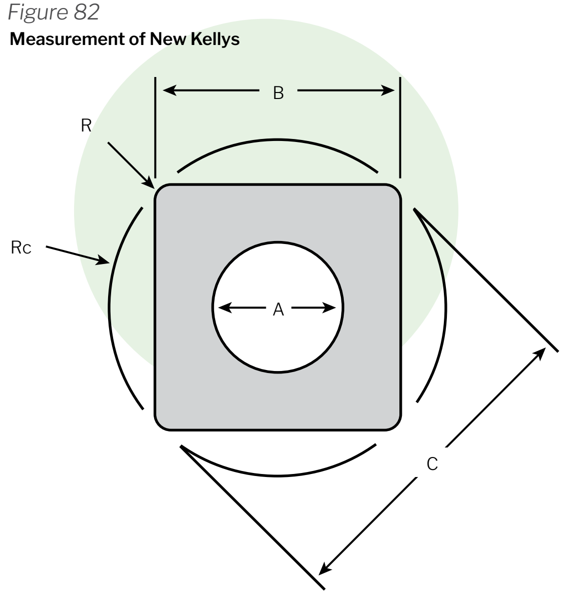
API Nom. Size, in.	Top Connection Standard left-hand, in.	Top Connection Optional left-hand, in.	Top OD Std, in.	Top OD Optional, in.	Bottom Connection Standard right-hand, in.	Bottom OD Standard, in.
2 ½	6 ⅝ Reg	4 ½ Reg	7 ¾	5 ¾	NC 26	3 ⅜
3	6 ⅝ Reg	4 ½ Reg	7 ¾	5 ¾	NC 31	4 ⅛
3 ½	6 ⅝ Reg	4 ½ Reg	7 ¾	5 ¾	NC 38	4 ¾
4 ¼	6 ⅝ Reg	4 ½ Reg	7 ¾	5 ¾	NC 46	6
					NC 50	6 ⅛
5 ¼	6 ⅝ Reg	4 ½ Reg	7 ¾	5 ¾	5 ½ FH	7
					NC 56	
‡6	6 ⅝ Reg	—	7 ¾	—	6 ⅝ FH	7 ¾

‡6-in. square kelly not API.

Hexagon Kellys

API Nom. Size, in.	Top Connection: Standard left-hand, in.	Top Connection: Optional left-hand, in.	Top OD: Std, in.	Top OD: Optional, in.	Bottom Connection: Standard right-hand, in.	Bottom OD: Standard, in.
3	6 ⅝ Reg	4 ½ Reg	7 ¾	5 ¾	NC 26	3 ⅜
3 ½	6 ⅝ Reg	4 ½ Reg	7 ¾	5 ¾	NC 31	4 ⅛
4 ¼	6 ⅝ Reg	4 ½ Reg	7 ¾	5 ¾	NC 38	4 ¾
5 ¼	6 ⅝ Reg	—.	7 ¾	—	NC 46	6
					NC 50	6 ⅛
6	6 ⅝ Reg	—	7 ¾	—	5 ½ FH	7
					NC 56	

Figure 82
Measurement of New Kellys

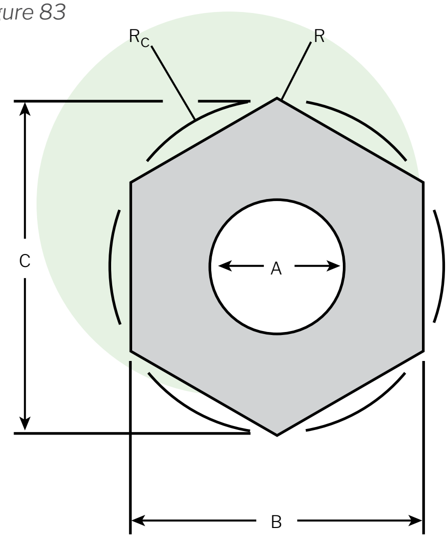


Square Kellys

API Nom. Size, in.	Max. Bore A, in.	Across Flats B, in.	Across Corner C, in.	Radius R†, in.	Radius Rc, in.
2 ½	1 ¼	2 ½	3.250	5/16	1 ⅝
3	1 ¾	3	3.875	⅜	1 15/16
3 ½	2 ¼	3 ½	4.437	½	2 7/32
4 ¼	2 13/16	4 ¼	5.500	½	2 ¾
5 ¼	3 ¼	5 ¼	6.750	⅝	3 ⅜
‡6	3 ½	6	7.625	¾	3 13/16

†Corner configuration at manufacturer's option.
‡6-in. square kelly not API.

Figure 83



Hexagon Kellys

API Nom. Size, in.	Max. Bore A, in.	Across Flats B, in.	Across Corner C, in.	Radius R†, in.	Radius Rc, in.
3	1 ½	3	3.375	¼	1 11/16
3 ½	1 ¾	3 ½	3.937	¼	1 31/32
4 ¼	2 ¼	4 ¼	4.781	5/16	2 25/32
5 ¼	3 ¼	5 ¼	5.900	⅜	3 61/64
6	3 ½	6	6.812	⅜	3 13/32

†Corner configuration at manufacturer's option.

Breaking in a New Kelly

When Picking Up a New Kelly

Before picking up a new kelly, check the kelly bushing. The rollers, pins or bearings may need replacing to return the drive assembly to like new status. Also check the bushing body for journal area wear and body spreading, a loose fitting drive unit can badly damage a new kelly on the first well drilled. Lubricate kelly drive surfaces before their first use.

Check Wear Pattern on Corners of Kelly

The major cause of kelly wear is rounding of the drive corners. The rate of wear is a function of the clearance or fit between the kelly and the rollers in the kelly bushing.

The more closely the kelly and rollers fit, the broader the wear pattern will be. A narrow wear pattern on the kelly's corners is an indication of a loose fit between the two components.

Rollers must fit the largest spot on the kelly flats. The API tolerances for distance across flats are quite large and bushings fitting properly in one area may appear loose at another point. A kelly made from a forging may have wide variations in tolerances, making it impossible to fit the roller closely at all points. Kellys manufactured by full length machining are manufactured to closer tolerances and fit the rollers better.

Figure 84

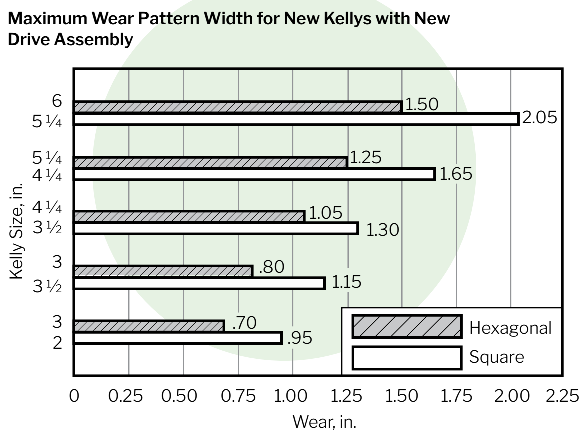
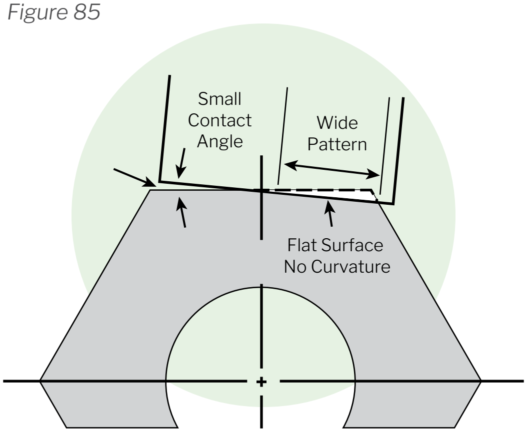
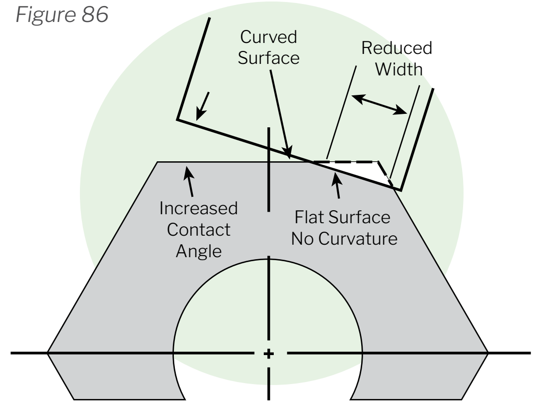


Figure 85



KELLYS

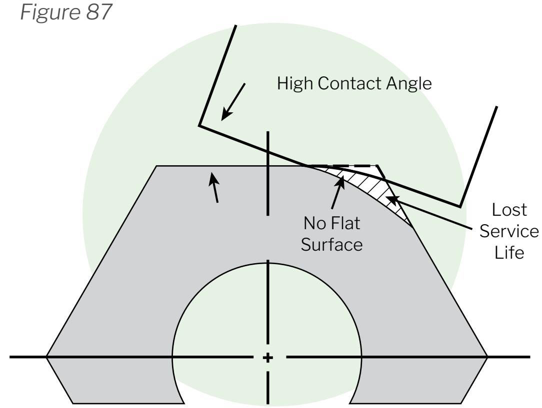
Figure 86



New kelly with new drive assembly. The drive edge will have a wide flat pattern with a small contact angle.

Kelly after considerable use with only new drive assembly. The drive edge will have a flat pattern of reduced width and increased contact angle. A curved surface will be visible on the kelly near the roller center.

Figure 87



Worn kelly with worn drive assembly. The drive edge is a curvature with a high contact angle.

Inspection

At regular intervals, have a DRILCO inspector check the kelly's threaded connections. These connections are subject to fatigue cracks like drill collar connections. Also, the drive section and upset areas should be inspected for cracks and wear patterns.

Kelly Saver Subs

Kelly saver subs protect the lower kelly connection from wear caused by making and breaking the drillpipe connection each time a joint of drillpipe or stand is drilled down. The saver sub also protects the top joint of casing from excessive wear if it is fitted with a rubber protector. In addition, the saver sub provides an area place the tongs when making-up or breaking-out the kelly. When a new stabilizer rubber is needed, an old sub re-worked or a brand new one ordered, contact a DRILCO representative before investing in a new kelly.

What to Do With an Old Kelly

Using the Other Corners

By employing a temperature controlled stubbing procedure, DRILCO can change ends on a kelly. This allows the kelly to drive against new corners. In this procedure welding is done only on the large diameter round sections. DRILCO does not recommend welding on the hexagonal or square surfaces of the kelly.

Remachine Drive Surfaces

With a Heli-Mill* kelly resurfacing mill, DRILCO can re-machine a kelly surface. This is a milling procedure that makes a clean-up cut on each driving surface.

Note: Oversize rotary drive rollers are used with a re-machined kelly. The bore diameter of your kelly must be small enough to allow sufficient wall thickness for re-machining. Contact a DRILCO representative for information concerning this procedure.

Straightening an Old Kelly

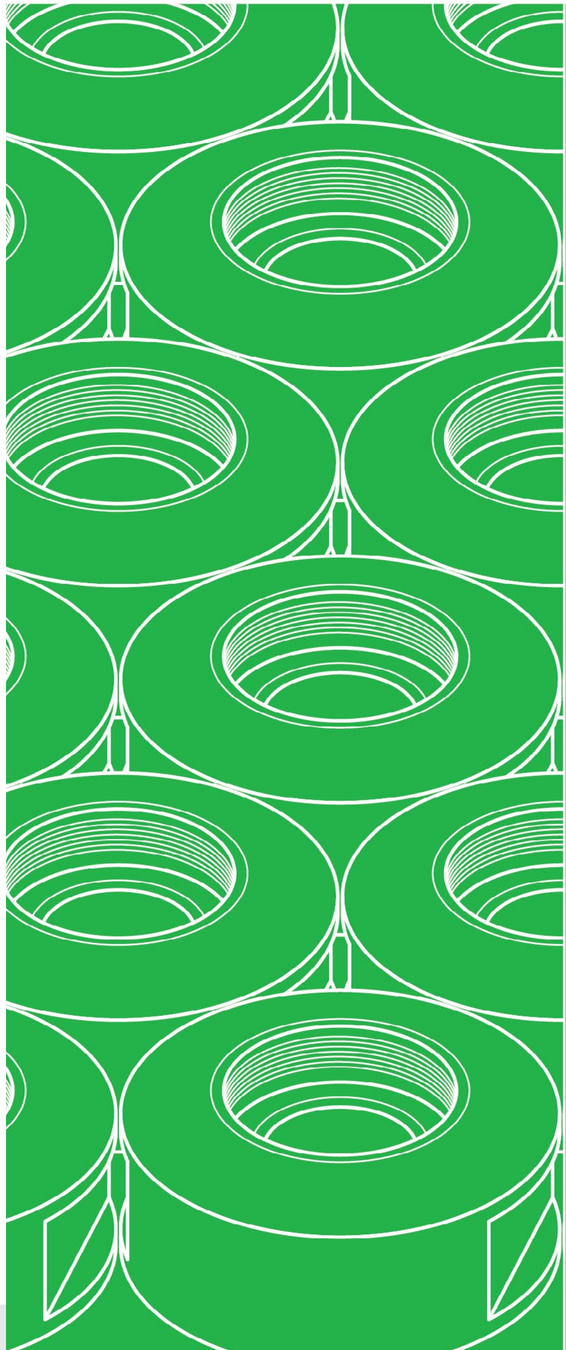
A bent kelly is under considerable stress as it is forced through the rotary drive bushings. DRILCO repair centers have straightening presses that can straighten a kelly, after which a qualified inspector will check the run-out.

Note: Should a DRILCO inspector determine that a kelly has reached the end of its useful life, a new kelly will be recommended.

SECTION EIGHT

INSPECTION

8



INSPECTION

INSPECTION

SYSTEMATIC FIELD INSPECTION

A systematic approach to routine inspection, maintenance and repair of downhole drilling tools is a necessity for proper operation and to extend the useful life of the equipment.

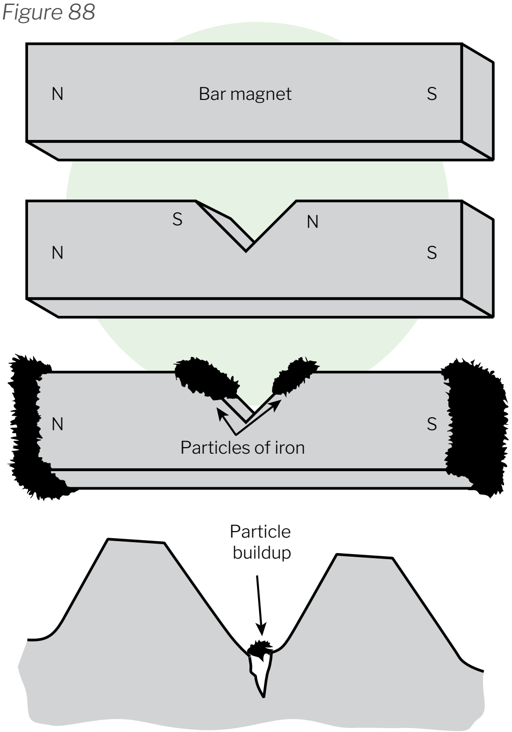
Most downhole drilling tool failures and resultant fishing jobs can be avoided by the use of periodic inspections and by providing maintenance and repair to the primary fatigue areas of equipment. The primary areas of fatigue are locations on the tool that receive the highest concentration of stress while operating. The majority of this stress is concentrated in several common areas on this equipment such as: connections, slip areas, upset areas, weld areas, radius changes, tube body, etc.

DRILCO field inspection services regularly utilize several types of nondestructive testing (NDT) methods to inspect these primary areas for potential problems. Visual (VT), magnetic particle examination (MT), liquid dye penetrant (PT), ultrasonic (UT) and electromagnetic (ET) testing methods are all utilized for efficiency and their superior detection capabilities.

When inspecting the threaded connections on drill collars, Hevi-Wate drillpipe, stabilizers, reamers, hole openers, kellys and other downhole drilling tools, the primary NDT method of inspection is magnetic particle examination. This common inspection procedure utilizes fluorescent magnetic particles to detect cracks in the threaded area of the connection and other locations on equipment as deemed necessary.

To illustrate the principle of magnetic particle inspection, magnetic particles ca be sprinkled on a bar which has been magnetized. The magnetized bar acts as a magnet with a north pole at one end and a south pole at the other end. The magnetic particles will be attracted to the poles of the magnet. If the bar is notched, each side of the notch becomes a pole of a magnet (Fig. 88). If the notch is narrow the magnetized particles will form a bridge between the poles. The notch in equipment components will be a crack and will behave the same way when the part magnetized.

Figure 88



DRILCO field inspectors are thoroughly trained in the principles and techniques of defect detection, correction and prevention. Rugged field trucks, equipped with calibrated and certified inspection equipment, provide access to remote locations (Fig. 89).

Figure 89

INSPECTION

Proper maintenance and inspection of downhole tools begins with proper cleaning. The threaded areas are cleaned by a wire brush adapted to an electric drill (Fig. 90). It is essential that all thread lubricant, dirt and corrosion be removed from the threads and shoulders prior to inspection.

Figure 90

All connections are magnetized with DC magnetizing coils utilizing the continuous method of particle application. The continuous method magnetizes the part to be inspected while a liquid solution suspending magnetic particles coated to fluoresce in ultraviolet (UV) light is applied to make sure the thread is properly magnetized to provide superior defect detection (Fig. 91). The magnetic particles suspended in the liquid solution are attracted to any cracks present shown by the principle illustrated in Figure 88.

Figure 91

Using UV light, an inspector's trained eye detects any build up of magnetic particles in the thread roots of the pin connection (Fig. 92). A magnifying mirror enables the inspector to look closely into the thread roots of the box connection.

Figure 92

If a crack indication is found, the inspector polishes it with a soft fibrous wheel to verify the presence of a fatigue crack (Fig. 93). The inspector then re-cleans, re-magnetizes and re-sprays the connection with the fluorescent magnetic particles and re-inspects with the UV light to verify that the indication is a crack.

Figure 93

As part of the inspection record, the drill collar serial number, tally length, OD and ID are noted. Also, connection size and type, field repairs made, and number of connections inspected are recorded. Joints requiring shop repairs are clearly marked to ensure proper identification of the repair required (Fig. 94). Tools are marked with the appropriate color paint to conform with API and/or customer requirements. Red marking is used on cracked collars and yellow on collars with other defects. White markings, along with the well-recognized "OK DRILCO" stenciling, are used to indicate inspected and approved equipment.

Figure 94

Drillpipe Inspection

The Drilcolog* inspection unit is an electromagnetic system for inspecting used drillpipe and tubing (Fig 95). The system incorporates a dual function inspection system with both transverse defect and wall loss detection capabilities. Sixteen (16) independent electronic channels, eight for transverse defects and eight for wall loss, are utilized for detection and display of internal and external corrosion, cracks, cuts and other transverse, three-dimensional and wall loss defects.

Figure 95

Ultrasonic End Area Inspection

Ultrasonic techniques may be used to inspect the slip areas and other high-stress areas of the drillpipe (Fig 96). These high-stress areas, located in the 36-in. section of tube nearest either tool joint, are areas of major concern when inspecting drillpipe. The DRILCO ultrasonic inspection equipment can locate internal fatigue cracks and washed out areas before they become problems.

Figure 96

Other Services and Specifications

In addition to the specific services shown above, other types of drilling tools, rig hoisting equipment and other types of equipment may be inspected by your DRILCO field inspection technician. Contact the local DRILCO representative for details.

API standards along with the DRILCO proprietary inspection specifications are used to provide the best inspection possible. Customer specifications and in-house procedures may be used at your request. Either way, the DRILCO trained inspectors will provide the highest quality service for your inspection dollar.

Field Repair

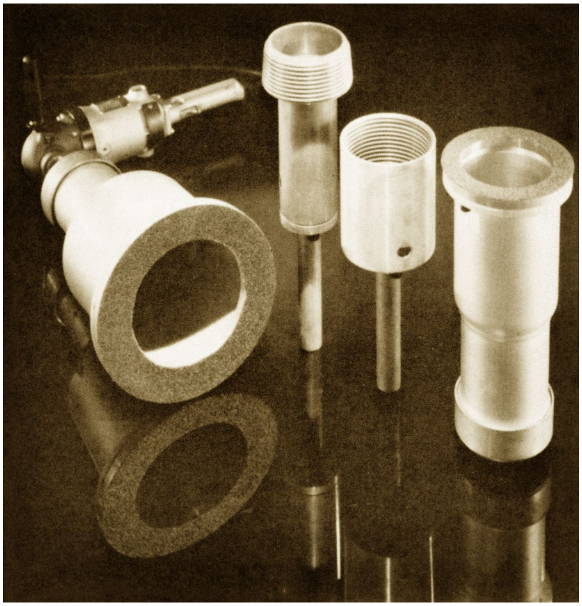
In addition to the inspection process, DRILCO field inspectors are also highly trained in the maintenance and field repair of downhole tools. Field repair may eliminate the costly need to ship equipment to the machine shop for repair. Trained technicians can remove minor thread and shoulder blemishes which, if not repaired, will cause damage to other connections in the string.

Shoulder Refacing

The DRILCO portable, electric powered shoulder refacing tools are designed to repair minor shoulder connection damage in the field (Fig. 97). Drill collar and drillpipe shoulder faces are smoothed with adhesive-backed emery paper, leaving a surface that is flat and smooth. Many connection shoulders can be repaired at the rig when such damage would normally require costly machine shop attention.

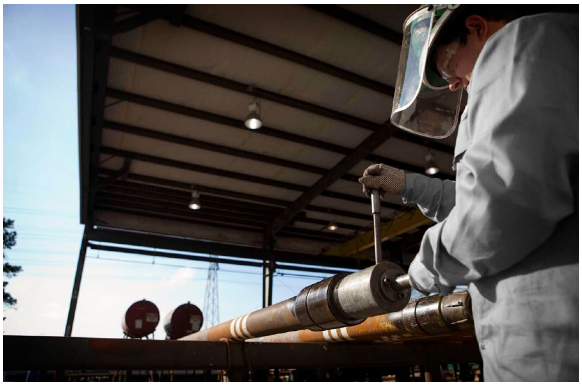
Caution: *Throughout the entire refacing operation, the inspector should wear eye protection.*

Figure 97



True alignment of the shoulder, perpendicular to the center line of the threads, is assured as the refacing tool mandrel is screwed on or into the connection threads (Fig. 98).

Figure 98



The adhesive-backed refacing discs are easy to apply and replace (Fig. 99).

Figure 99

The refacing tool is rotated by a heavy-duty electric sander and the pressure is applied by the operator along the axis of the threaded connection (Fig. 100). The drive tube is made from aluminum to reduce the weight of the assembly.

Caution: *The sander should not be used unless properly grounded.*

Figure 100

Extreme care should be taken in removing only the minimum amount of material required. When making field repairs, operators of the tool should be skilled and understand service conditions of the product to assure the proper application of the refacing tool. It is a good practice not to remove more than $1/32$ in. (0.8 mm) from a box or pin shoulder at any refacing and not more than $1/16$ in. (1.6 mm) cumulatively (see API Recommended Practice RP 7G, current edition).

Note: Portable equipment used to repair threaded connections in the field will not restore the product to the tolerances of a new part.

Copper Sulfate Solution

After refacing, an anti-gall coating of copper sulfate, is applied to the shoulder surface (Fig. 101). Copper sulfate solution mixing instructions are found on page 165.

Caution: *Eye protection and appropriate hand protection should be worn when mixing or handling copper sulfate solution. Always pour acid into water. Mix the solution in an area with an eye wash fountain or where large amounts of water are available for flushing, in case solution comes in contact with any part of the body.*

Figure 101

After completion of the inspection and repair operation, a rust preventative is applied to all connections on tools that are to be stored before the next use (Fig. 102). On tools that are to be used immediately, an API thread compound is applied to the threads and shoulders (Fig. 103).

Figure 102

Figure 103

Mixing the Copper Sulfate Anti-Gall Solution

The copper sulfate solution is prepared by dissolving 4 heaping tablespoons (53 cc) of blue vitriol (blue stone copper sulfate crystals or powder) in ⅔ quart (600 cc) of water and adding 3 tablespoons (40 cc) of sulfuric acid.

Caution: *Eye protection and appropriate hand protection should be worn when mixing or handling copper sulfate solution. Always pour acid into water. Mix the solution in an area with eye wash fountain, or where large amounts of water are available for flushing, in case solution comes in contact with any part of the body.*

How to Use Your Tool Joint Identifier

1. With the thread form, determine the number of threads per inch in the pin or box (Fig. 104). On the scale, threads per inch are indicated by the number following the type of joint.

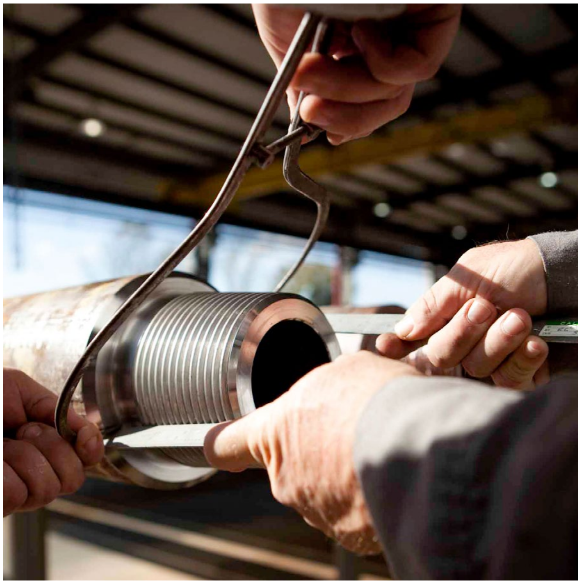
Figure 104

2. On pins without a relief-groove or turned cylindrical diameter, caliper diameter at base (Fig. 105).

Figure 105

3. To measure tapered diameter of pins with relief-grooves or cylindrical diameters, ask someone to hold two straight edges against threads and caliper at shoulder as shown (Fig. 106).

Figure 106



4. On the identifier scale, find the type of joint which corresponds to the pin base diameter measured in Figures 105 and 106. Place one end of caliper in the notch and read the corresponding connection size at the other end of the caliper tip (Fig. 107).

Figure 107

5. To find the type of box, hold the end of the scale marked box to mouth of counterbore, as shown, and read the nearest size and type of joint having corresponding number of threads per inch (Fig. 108).

Figure 108

Pin base diameters can vary widely on the same size joints, but no inaccuracies will be experienced if the nearest size is read and coupled with the correct number of threads per inch. As an example, 3½ FH, 3½ IF and 3½ H-90 have nearly the same pin base diameter, but can be easily distinguished by the number of threads per inch.

International Inspection Services

DRILCO inspection systems are air portable, self supporting and quickly available from strategic locations around the world. Experienced inspectors are trained in defect detection and downhole tool maintenance and field repair. Inspectors are qualified to train the customer's operating personnel in field maintenance and defect prevention.

Special compact and light-weight equipment facilitates travel to offshore and remote locations (Fig. 109).

Figure 109

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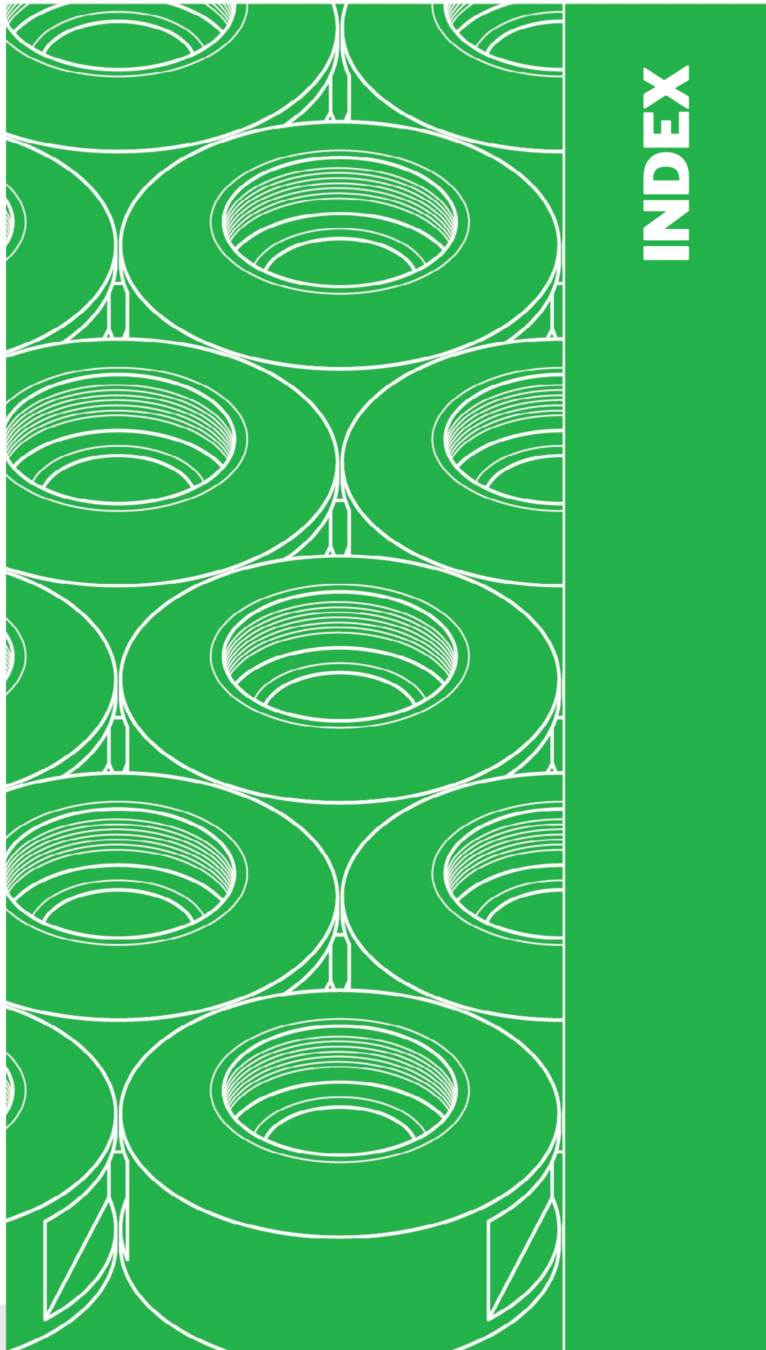

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Drilling Assembly Handbook

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