Chapter 1

FUNDAMENTAL ASPECTS OF CASING DESIGN

1.1 PURPOSE OF CASING

At a certain stage during the drilling of oil and gas wells, it becomes necessary to line the walls of a borehole with steel pipe which is called casing. Casing serves numerous purposes during the drilling and production history of oil and gas wells, these include:

1. Keeping the hole open by preventing the weak formations from collapsing, i.e., caving of the hole.

2. Serving as a high strength flow conduit to surface for both drilling and production fluids.

3. Protecting the freshwater-bearing formations from contamination by drilling and production fluids.

4. Providing a suitable support for wellhead equipment and blowout preventers for controlling subsurface pressure, and for the installation of tubing and subsurface equipment.

5. Providing safe passage for running wireline equipment.

6. Allowing isolated communication with selectively perforated formation(s) of interest.

1.2 TYPES OF CASING

When drilling wells, hostile environments, such as high-pressured zones, weak and fractured formations, unconsolidated formations and sloughing shales, are often encountered. Consequently, wells are drilled and cased in several steps to seal off these troublesome zones and to allow drilling to the total depth. Different casing sizes are required for different depths, the five general casings used to complete a well are: conductor pipe, surface casing, intermediate casing, production casing and liner. As shown in Fig. 1.1, these pipes are run to different depths and one or two of them may be omitted depending on the drilling conditions; they may also be run as liners or in combination with liners. In offshore platform operations, it is also necessary to run a cassion pipe.

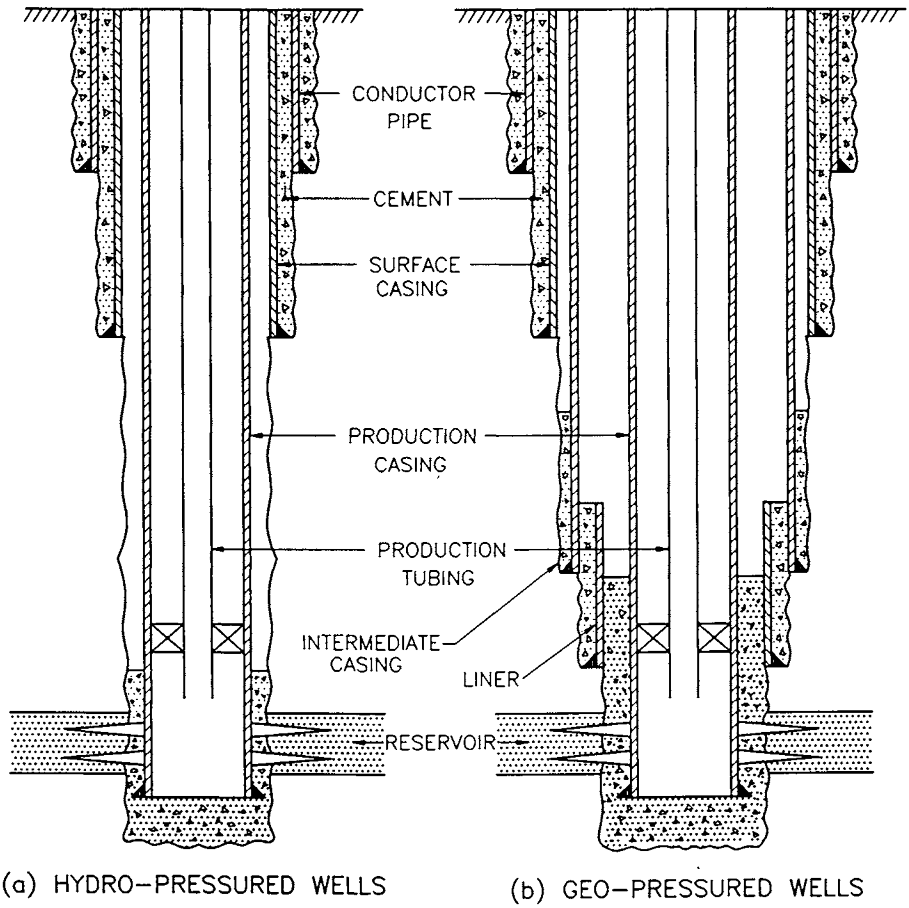

Fig. 1.1: Typical casing program showing different casing sizes and their setting depths.

1.2.1 Cassion Pipe

On an offshore platform, a cassion pipe, usually 26 to 42 in. in outside diameter (OD), is driven into the sea bed to prevent washouts of near-surface unconsolidated formations and to ensure the stability of the ground surface upon which the rig is seated. It also serves as a flow conduit for drilling fluid to the surface. The cassion pipe is tied back to the conductor or surface casing and usually does not carry any load.

1.2.2 Conductor Pipe

The outermost casing string is the conductor pipe. The main purpose of this casing is to hold back the unconsolidated surface formations and prevent them from falling into the hole. The conductor pipe is cemented back to the surface and it is either used to support subsequent casings and wellhead equipment or the pipe is cut off at the surface after setting the surface casing. Where shallow water or gas flow is expected, the conductor pipe is fitted with a diverter system above the flowline outlet. This device permits the diversion of drilling fluid or gas flow away from the rig in the event of a surface blowout. The conductor pipe is not shut-in in the event of fluid or gas flow, because it is not set in deep enough to provide any holding force.

The conductor pipe, which varies in length from 40 to 500 ft onshore and up to 1,000 ft offshore, is 7 to 20 in. in diameter. Generally, a 16-in. pipe is used in shallow wells and a 20-in. in deep wells. On offshore platforms, conductor pipe is usually 20 in. in diameter and is cemented across its entire length.

1.2.3 Surface Casing

The principal functions of the surface casing string are to: hold back unconsolidated shallow formations that can slough into the hole and cause problems, isolate the freshwater-bearing formations and prevent their contamination by fluids from deeper formations and to serve as a base on which to set the blowout preventers. It is generally set in competent rocks, such as hard limestone or dolomite, so that it can hold any pressure that may be encountered between the surface casing seat and the next casing seat.

Setting depths of the surface casing vary from a few hundred feet to as much as 5,000 ft. Sizes of the surface casing vary from 7 to 16 in. in diameter, with $10\frac{3}{4}$ in. and $13\frac{3}{8}$ in. being the most common sizes. On land, surface casing is usually cemented to the surface. For offshore wells, the cement column is frequently limited to the kickoff point.

1.2.4 Intermediate Casing

Intermediate or protective casing is set at a depth between the surface and production casings. The main reason for setting intermediate casing is to case off the formations that prevent the well from being drilled to the total depth. Troublesome zones encountered include those with abnormal formation pressures, lost circulation, unstable shales and salt sections. When abnormal formation pressures are present in a deep section of the well, intermediate casing is set to protect formations below the surface casing from the pressures created by the drilling fluid specific weight required to balance the abnormal pore pressure. Similarly, when normal pore pressures are found below sections having abnormal pore pressure, an additional intermediate casing may be set to allow for the use of more economical, lower specific weight, drilling fluids in the subsequent sections. After a troublesome lost circulation, unstable shale or salt section is penetrated, intermediate casing is required to prevent well problems while drilling below these sections.

Intermediate casing varies in length from 7,000 ft to as much as 15,000 ft and from 7 in. to $11\frac{3}{4}$ in. in outside diameter. It is commonly cemented up to 1,000 ft from the casing shoe and hung onto the surface casing. Longer cement columns are sometimes necessary to prevent casing buckling.

1.2.5 Production Casing

Production casing is set through the prospective productive zones except in the case of open-hole completions. It is usually designed to hold the maximal shut-in pressure of the producing formations and may be designed to withstand stimulating pressures during completion and workover operations. It also provides protection for the environment in the event of failure of the tubing string during production operations and allows for the production tubing to be repaired and replaced.

Production casing varies from $4\frac{1}{2}$ in. to $9\frac{5}{8}$ in. in diameter, and is cemented far enough above the producing formations to provide additional support for subsurface equipment and to prevent casing buckling.

1.2.6 Liners

Liners are the pipes that do not usually reach the surface, but are suspended from the bottom of the next largest casing string. Usually, they are set to seal off troublesome sections of the well or through the producing zones for economic reasons. Basic liner assemblies currently in use are shown in Fig. 1.2, these include: drilling liner, production liner, tie-back liner, scab liner, and scab tie-back liner (Brown - Hughes Co., 1984).

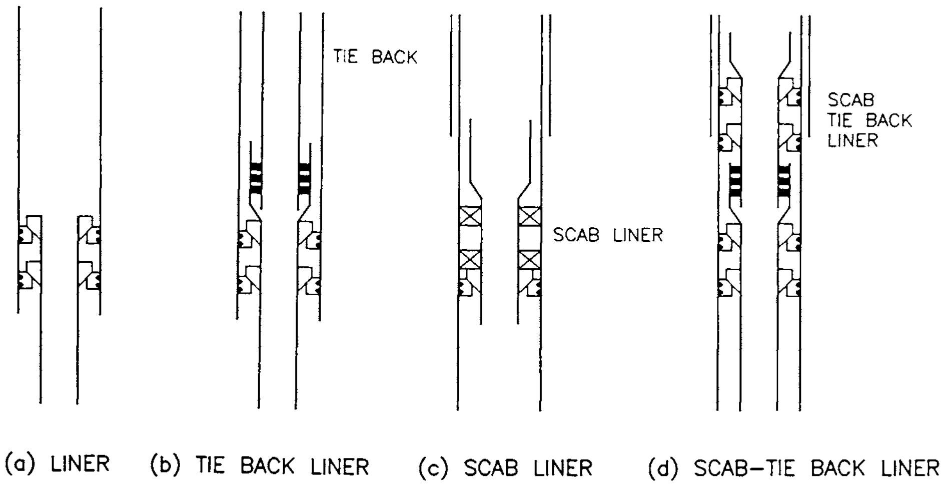

Fig. 1.2: Basic liner system. (After Brown - Hughes Co., 1984.)

Drilling liner: Drilling liner is a section of casing that is suspended from the existing casing (surface or intermediate casing). In most cases, it extends downward into the openhole and overlaps the existing casing by 200 to 400 ft. It is used to isolate abnormal formation pressure, lost circulation zones, heaving shales and salt sections, and to permit drilling below these zones without having well problems.

Production liner: Production liner is run instead of full casing to provide isolation across the production or injection zones. In this case, intermediate casing or drilling liner becomes part of the completion string.

Tie-back liner: Tie-back liner is a section of casing extending upwards from the top of the existing liner to the surface. This pipe is connected to the top of the liner (Fig. 1.2(b)) with a specially designed connector. Production liner with tie-back liner assembly is most advantageous when exploratory drilling below the productive interval is planned. It also gives rise to low hanging-weights in the upper part of the well.

Scab liner: Scab liner is a section of casing used to repair existing damaged casing. It may be cemented or sealed with packers at the top and bottom (Fig. 1.2(c)).

Scab tie-back liner: This is a section of casing extending upwards from the existing liner, but which does not reach the surface and is normally cemented in place. Scab tie-back liners are commonly used with cemented heavy-wall casing to isolate salt sections in deeper portions of the well.

The major advantages of liners are that the reduced length and smaller diameter of the casing results in a more economical casing design than would otherwise be possible and they reduce the necessary suspending capacity of the drilling rig. However, possible leaks across the liner hanger and the difficulty in obtaining a good primary cement job due to the narrow annulus must be taken into consideration in a combination string with an intermediate casing and a liner.

1.3 PIPE BODY MANUFACTURING

All oilwell tubulars including casing have to meet the requirements of the API (American Petroleum Institute) Specification 5CT (1992). formerly Specifications 5A, 5AC, 5AQ and 5AX. Two basic processes are used to manufacture casing: seamless and continuous electric weld.

1.3.1 Seamless Pipe

Seamless pipe is a wrought steel pipe manufactured by a seamless process. A large percentage of tubulars and high quality pipes are manufactured in this way. In the seamless process, a billet is pierced by a mandrel and the pierced tube is subsequently rolled and re-rolled until the finished diameters are obtained (Fig. 1.3). The process may involve a plug mill or mandrel mill rolling. In a plug mill, a heated billet is introduced into the mill. where it is held by two rollers that rotate and advance the billet into the piercer. In a mandrel mill, the billet is held by two obliquely oriented rotating rollers and pierced by a central plug. Next, it passes to the elongator where the desired length of the pipe is obtained. In the plug mills the thickness of the tube is reduced by central plugs with two single grooved rollers.

In mandrel mills, sizing mills similar in design to the plug mills are used to produce a more uniform thickness of pipe. Finally, reelers similar in design to the piercing mills are used to burnish the pipe surfaces and to produce the final pipe dimensions and roundness.

1.3.2 Welded Pipe

In the continuous electric process, pipe with one longitudinal seam is produced by electric flash or electric resistance welding without adding extraneous metal. In the electric flash welding process. pipes are formed from a sheet with the desired dimensions and welded by simultaneously flashing and pressing the two ends. In the electric resistance process. pipes are manufactured from a coiled

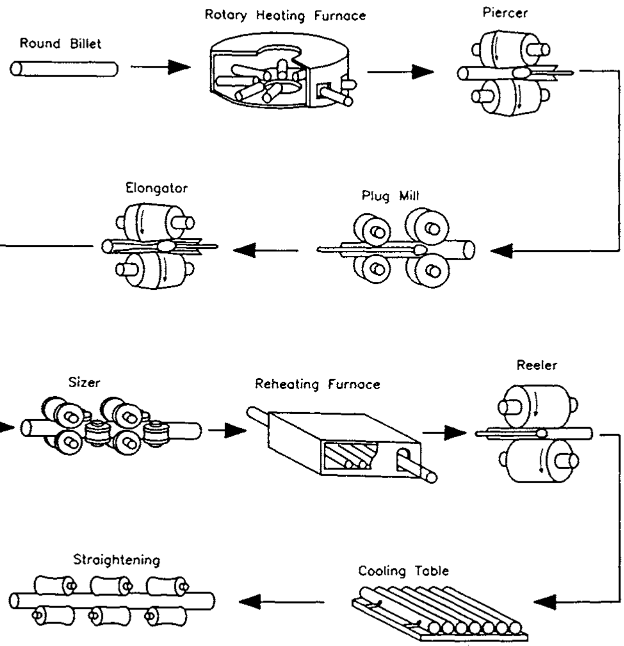

Fig. 1.3: Plug Mill Rolling Process for Kawasaki's 7–16$\frac{3}{8}$ in. pipe. (Courtesy of Kawasaki Steel Corporation.)

sheet which is fed into the machine, formed and welded by electric arc (Fig. 1.4). Pipe leaving the machine is cut to the desired length. In both the electric flash and electric arc welding processes, the casing is passed through dies that deform it sufficiently to exceed the elastic limit, a process which raises the elastic limit in the direction stressed and reduces it somewhat in the perpendicular direction: Bauchinger effect. Casing is also cold-worked during manufacturing to increase its collapse resistance.

1.3.3 Pipe Treatment

Careful control of the treatment process results in tension and burst properties equivalent to 95,000 psi circumferential yield.

Strength can be imparted to tubular goods in several ways. Insofar as most steels are relatively mild (0.30 % carbon), small amounts of manganese are added to them and the material is merely normalized. When higher-strength materials are required, they are normalized and tempered. Additional physical strength may be obtained by quenching and tempering (QT) a mild or low-strength steel. This QT process improves fracture toughness, reduces the metal's sensitivity to notches,

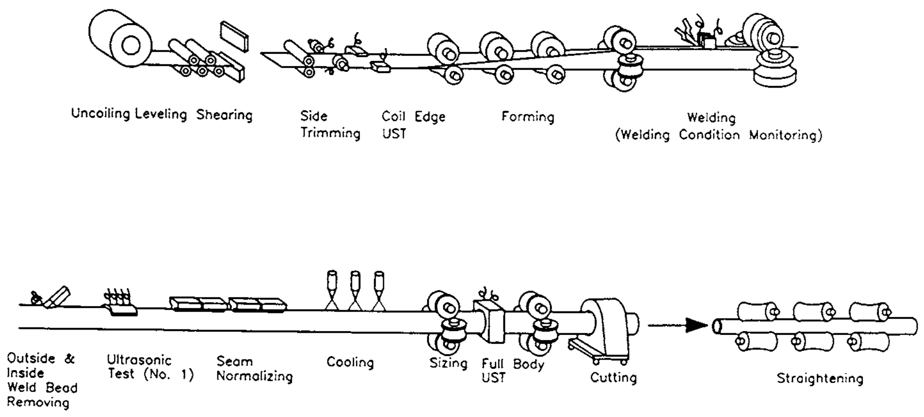

Fig. 1.4: Nippon's Electric Welding Method of manufacturing casing. (Courtesy of Nippon Steel Corporation.)

lowers the brittle fracture temperature and decreases the cost of manufacturing. Thus, many of the tubulars manufactured today are made by the low cost QT process, which has replaced many of the alloy steel (normalized and tempered) processes.

Similarly, some products, which are known as 'warm worked', may be strengthened or changed in size at a temperature below the critical temperature. This may also change the physical properties just as cold-working does.

1.3.4 Dimensions and Weight of Casing and Steel Grades

All specifications of casing include outside diameter, wall thickness, drift diameter, weight and steel grade. In recent years the API has developed standard specifications for casing, which have been accepted internationally by the petroleum industry.

1.3.5 Diameters and Wall Thickness

As discussed previously, casing diameters range from $4\frac{1}{2}$ to 24 in. so they can be used in different sections (depths) of the well. The following tolerances, from API Spec. 5CT (1992), apply to the outside diameter (OD) of the casing immediately behind the upset for a distance of approximately 5 inches:

Casing manufacturers generally try to prevent the pipe from being undersized to ensure adequate thread run-out when machining a connection. As a result, most

Table 1.1: API manufacturing tolerances for casing outside diameter. (After API Spec. 5CT, 1992.)

Outside diameter (in.)	Tolerances (in.)	
$1.05 - 3\frac{1}{2}$	$+\frac{3}{32}$	$-\frac{1}{32}$
$4 - 5$	$+\frac{7}{64}$	$-0.75\,\%$ OD
$5\frac{1}{2} - 8\frac{5}{8}$	$+\frac{1}{8}$	$-0.75\,\%$ OD
$\geq 9\frac{5}{8}$	$+\frac{5}{32}$	$-0.75\,\%$ OD

casing pipes are found to be within $\pm 0.75\,\%$ of the tolerance and are slightly oversized.

Inside diameter (ID) is specified in terms of wall thickness and drift diameter. The maximal inside diameter is, therefore, controlled by the combined tolerances for the outside diameter and the wall thickness. The minimal permissible pipe wall thickness is 87.5 % of the nominal wall thickness, which in turn has a tolerance of –12.5 %.

The minimal inside diameter is controlled by the specified drift diameter. The drift diameter refers to the diameter of a cylindrical drift mandrel, Table 1.2, that can pass freely through the casing with a reasonable exerted force equivalent to the weight of the mandrel being used for the test (API Spec. 5CT, 1992). A bit of a size smaller than the drift diameter will pass through the pipe.

Table 1.2: API recommended dimensions for drift mandrels. (After API Spec. 5CT, 1992.)

Casing and liner (in.)	Length (in.)	Diameter (ID) (in.)
$\leq 8\frac{5}{8}$	6	ID $-\frac{1}{8}$
$9\frac{5}{8} - 13\frac{3}{8}$	12	ID $-\frac{5}{32}$
≥ 16	12	ID $-\frac{3}{16}$

The difference between the inside diameter and the drift diameter can be explained by considering a 7-in., 20 lb/ft casing, with a wall thickness, t, of 0.272-in.

$$\begin{aligned}\text{Inside diameter} &= \text{OD} - 2t \\ &= 7 - 0.544 \\ &= 6.456 \text{ in.}\end{aligned}$$

$$
\begin{aligned}
\text{Drift diameter} &= \text{ID} - \tfrac{1}{8} \\
&= 6.456 - 0.125 \\
&= 6.331 \text{ in.}
\end{aligned}
$$

Drift testing is usually carried out before the casing leaves the mill and immediately before running it into the well. Casing is tested throughout its entire length.

1.3.6 Joint Length

The lengths of pipe sections are specified by API RP 5B1 (1988), in three major ranges: R1, R2 and R3, as shown in Table 1.3.

Table 1.3: API standard lengths of casing. (After API RP 5B1, 1988.)

Range	Length (ft)	Average length (ft)
1	16 - 25	22
2	25 - 34	31
3	over 34	42

Generally, casing is run in R3 lengths to reduce the number of connections in the string, a factor that minimizes both rig time and the likelihood of joint failure in the string during the life of the well (joint failure is discussed in more detail on page 18). R3 is also easy to handle on most rigs because it has a single joint.

1.3.7 Makeup Loss

When lengths of casing are joined together to form a string or section, the overall length of the string is less than the sum of the individual joints. The reason that the completed string is less than the sum of the parts is the makeup loss at the couplings.

It is clear from Fig. 1.5 that the makeup loss per joint for a string made up to the powertight position is:

$$L_l = \frac{L_c}{2} - J$$

where:

l_j = length of pipe.
l_{jc} = length of the casing with coupling.
L_c = length of the coupling.

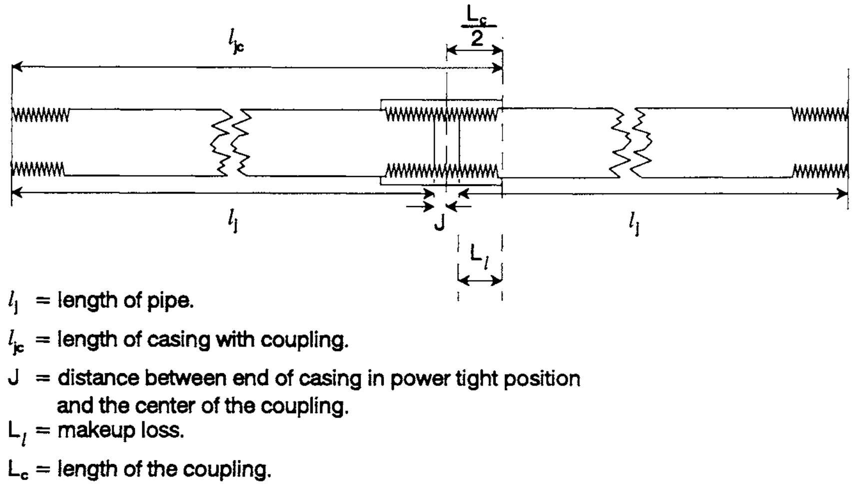

Fig. 1.5: Makeup loss per joint of casing.

J = distance between the casing end in the power tight position and the coupling center.
L_l = makeup loss.

EXAMPLE 1-1[a]:

Calculate the makeup loss per joint for a $9\frac{5}{8}$-in., N-80, 47 lb/ft casing with short threads and couplings. Also calculate the loss in a 10,000-ft well (ignore tension effects) and the additional length of madeup string required to reach true vertical depth (TVD). Express the answer in general terms of l_{jc}, the average length of the casing in feet of the tallied (measured) casing and then calculate the necessary makeup lengths for l_{jc} = 21, 30 and 40 – assumed average lengths of R1, R2 and R3 casing available.

Solution:

For a casing complete with couplings, the length l_{jc} is the distance measured from the uncoupled end of the pipe to the outer face of the coupling at the opposite end, with the coupling made-up power-tight (API Spec. 5CT).

From Table 1.4, $L_c = 7\frac{3}{4}$ in. and J = 0.500-in. Thus,

$$\begin{aligned} L_l &= \frac{L_c}{2} - J \\ &= 3.875 - 0.500 \\ &= 3.375 \text{ in.} \end{aligned}$$

[a]Based on Example. 2.1, Craft et al. (1962).

Table 1.4: Round-thread casing dimensions for long threads and couplings.

D in.	t in.	$J^{\dagger}$ in.	$L_c^{\ddagger}$ in.
4.5	All	0.5	7
5	All	0.5	7.75
5.5	All	0.5	8
6.625	All	0.5	8.75
7	All	0.5	9
7.625	All	0.5	9.25
8.625	All	0.5	10
9.625	All	0.5	10.5

† STD 5B ‡ Spec 5CT

The number of joints in 1,000 ft of tallied casing is $1{,}000/l_{jc}$ and, therefore, the makeup loss in 1,000 ft is:

$$\begin{aligned}\text{Makeup loss per 1,000 ft} &= 3.375 \times 1{,}000/l_{jc} \\ &= 3{,}375/l_{jc} \text{ in.} \\ &= 3{,}375/(12 l_{jc}) \text{ ft}\end{aligned}$$

As tension effects are ignored this is the makeup loss in *any* 1,000-ft section.

If L_T is defined as the total casing required to make 1,000 ft of made-up, power-tight string, then:

$$\begin{aligned}\text{makeup loss} &= \frac{L_T}{1{,}000}\left(\frac{3{,}375}{12 l_{jc}}\right) \text{ ft} \\ 1{,}000 &= L_T - L_T\left(\frac{3{,}375}{12 l_{jc}}\right) \text{ ft} \\ \Rightarrow L_T &= \left(\frac{1{,}000 l_{jc}}{l_{jc} - 0.28125}\right) \text{ ft}\end{aligned}$$

Finally, using the general form of the above equation in L_T, Table 1.5 can be produced to give the makeup loss in a 10,000-ft string.

1.3.8 Pipe Weight

According to the API Bul. 5C3 (1989), pipe weight is defined as nominal weight, plain end weight, and threaded and coupled weight. Pipe weight is usually ex-

Table 1.5: Example 1: makeup loss in 10,000 ft strings for different API casing lengths.

R	L (ft)	L_T (ft)	makeup Loss (ft)
1	21	10,135.75	135.75
2	30	10,094.63	94.63
3	40	10,070.81	70.81

pressed in lb/ft. The API tolerances for weight are: +6.5 % and -3.5 % (API Spec. 5CT, 1992).

Nominal weight is the weight of the casing based on the theoretical weight per foot for a 20-ft length of threaded and coupled casing joint. Thus, the nominal weight, W_n in lb/ft, is expressed as:

$$W_n = 10.68\,(d_o - t)\,t + 0.0722\,d_o^2 \tag{1.1}$$

where:

W_n = nominal weight per unit length, lb/ft.
d_o = outside diameter, in.
t = wall thickness, in.

The nominal weight is not the exact weight of the pipe, but rather it is used for the purpose of identification of casing types.

The plain end weight is based on the weight of the casing joint excluding the threads and couplings. The plain end weight, W_{pe}, in lb/ft, is expressed as:

$$W_{pe} = 10.68\,(d_o - t)\ \text{lb/ft} \tag{1.2}$$

Threaded and coupled weight, on the other hand, is the average weight of the pipe joint including the threads at both ends and coupling at one end when in the power tight position. Threaded and coupled weight, W_{tc}, is expressed as:

$$\begin{aligned} W_{tc} \;=\; & \frac{1}{20}\,\{\,(W_{pe}\ [20 - (L_c + 2J)/24] + \text{Weight of coupling} \\ & - \text{Weight removed in threading two pipe ends}\,\} \end{aligned} \tag{1.3}$$

where:

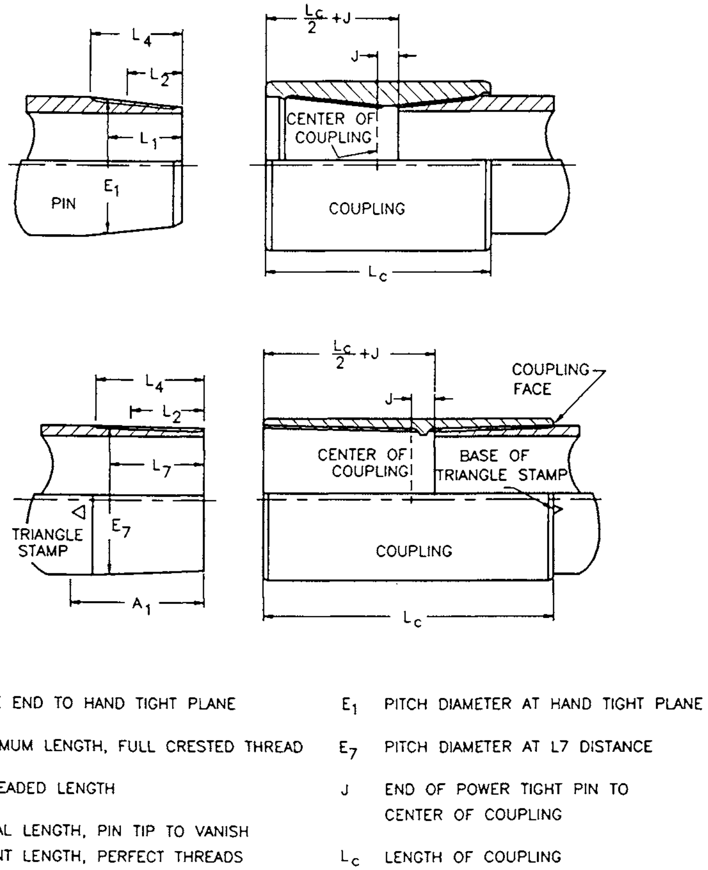

Fig. 1.6: Basic axial dimensions of casing couplings: API Round threads (top), API Buttress threads (bottom).

W_{tc} = threaded and coupled weight, lb/ft.
L_c = coupling length, in.
J = distance between the end of the pipe and center of the coupling in the power tight position, in.

The axial dimensions for both API Round and API Buttress couplings are shown in Fig. 1.6.

1.3.9 Steel Grade

The steel grade of the casing relates to the tensile strength of the steel from which the casing is made. The steel grade is expressed as a code number which consists of a letter and a number, such as N-80. The letter is arbitrarily selected to provide a unique designation for each grade of casing. The number designates the minimal yield strength of the steel in thousands of psi. Strengths of API steel grades are given in Table 1.6.

Hardness of the steel pipe is a critical property especially when used in H_2S (sour) environments. The L-grade pipe has the same yield strength as the N-grade, but the N-grade pipe may exceed 22 Rockwell hardness and is, therefore, not suitable for H_2S service. For sour service, the L-grade pipe with a hardness of 22 or less, or the C-grade pipe can be used.

Many non-API grades of pipes are available and widely used in the drilling industry. The strengths of some commonly used non-API grades are presented in Table 1.7. These steel grades are used for special applications that require very high tensile strength, special collapse resistance or other properties that make steel more resistant to H_2S.

Table 1.6: Strengths of API steel grades. (API Spec. 5CT, 1992.)

API Grade	Yield Strength (psi) Minimum	Yield Strength (psi) Maximum	Minimum Ultimate Tensile Strength (psi)	Minimum Elongation * (%)
H-40	40,000	80,000	60,000	29.5
J-55	55,000	80,000	75,000	24.0
K-55	55,000	80,000	95,000	19.5
L-80	80,000	95,000	95,000	19.5
N-80	80,000	110,000	100,000	18.5
C-90	90,000	105,000	100,000	18.5
C-95	95,000	110,000	105,000	18.0
T-95	95,000	110,000	105,000	18.0
P-110	110,000	140,000	125,000	15.0
Q-125	125,000	150,000	135,000	14.0

* Elongation in 2 inches, minimum per cent for a test specimen with an area ≥ 0.75 in^2.

1.4 CASING COUPLINGS AND THREAD ELEMENTS

A coupling is a short piece of pipe used to connect the two ends, pin and box, of the casing. Casing couplings are designed to sustain high tensile load while

Table 1.7: Strengths of non-API steel grades.

Non-API Grade	Manufacturer	Yield Strength (psi) Minimum	Maximum	Minimal Ultimate Tensile Strength (psi)	Minimal* Elongation (%)
S-80	Lone Star Steel	75,000 **	-	75,000	20.0
		55,000 †	-		
Mod. N-80	Mannesmann	80,000	95,000	100,000	24.0
C-90 ‡	Mannesmann	90,000	105,000	120,000	26.0
SS-95	Lone Star Steel	95,000 **	-	95,000	18.0
		75,000 †	-		
S00-95	Mannesmann	95,000	110,000	110,000	20.0
S-95	Lone Star Steel	95,000 **	-	110,000	16.0
		92,000 †	-		
S00-125	Mannesmann	125,000	150,000	135,000	18.0
S00-140	Mannesmann	140,000	165,000	150,000	17.0
V-150	U.S. Steel	150,000	180,000	160,000	14.0
S00-155	Mannesmann	155,000	180,000	165,000	20.0

* Test specimen with area greater than 0.75 sq in.
** Circumferential.
† Longitudinal
‡ Maximal ultimate tensile strength of 120,000 psi.

at the same time providing pressure containment from both net internal and external pressures. Their ability to resist tension and contain pressure depends primarily on the type of threads cut on the coupling and at the pipe ends. With the exception of a growing number of proprietary couplings, the configurations and specifications of the couplings are standardized by API (API RP 5B1, 1988).

1.4.1 Basic Design Features

In general, casing couplings are specified by the types of threads cut on the pipe ends and coupling. The principal design features of threads are: form, taper, height, lead and pitch diameter (Fig. 1.7).

Form: Design of thread form is the most obvious way to improve the load bearing capacity of a casing connection. The two most common thread

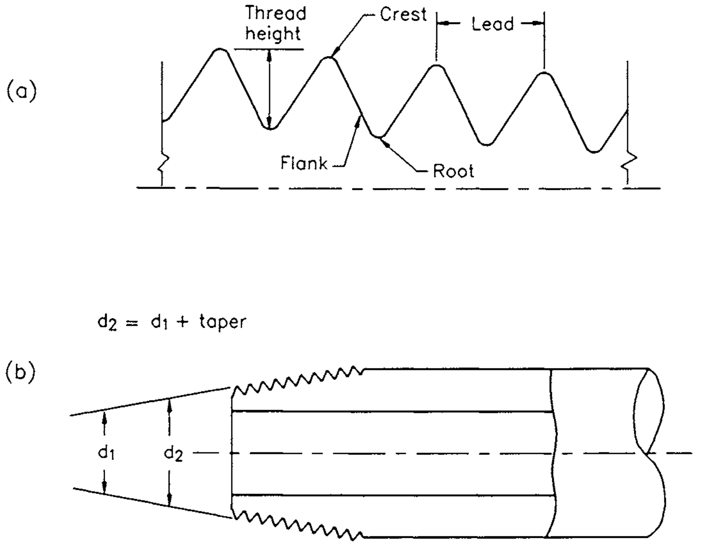

Fig. 1.7: Basic elements of a thread. The thread taper is the change in diameter per unit distance moved along the thread axis. Thus, the change in diameter, $d_2 - d_1$, per unit distance moved along the thread axis, is equal to the taper per unit on diameter. Refer to Figs. 9 and 10 for further clarification.

forms are: squared and V-shape. The API uses round and buttress threads which are special forms of squared and V-shape threads.

Taper: Taper is defined as the change in diameter of a thread expressed in inches per foot of thread length. A steep taper with a short connection provides for rapid makeup. The steeper the taper, however, the more likely it is to have a jumpout failure, and the shorter the thread length, the more likely it is to experience thread shear failure.

Height: Thread height is defined as the distance between the crest and the root of a thread measured normal to the axis of the thread. As the thread height of a particular thread shape increases, the likelihood of jumpout failure decreases; however, the critical material thickness under the last engaged thread decreases.

Lead: Lead is defined as the distance from one point on the thread to the corresponding point on the adjacent thread and is measured parallel to the thread axis.

Pitch Diameter: Pitch diameter is defined as the diameter of an imaginary cone that bisects each thread midway between its crest and root.

Threaded casing connections are often rated according to their joint efficiency and sealing characteristics. Joint efficiency is defined as the tensile strength of the joint divided by the tensile strength of the pipe. Generally, failure of the joint is recognized as jumpout, fracture, or thread shear.

Jumpout: In a jumpout, the pin and box separate with little or no damage to the thread element. In a compression failure, the pin progresses further into the box.

Fracture: Fracturing occurs when the pin threaded section separates from the pipe body or there is an axial splitting of the coupling. Generally this occurs at the last engaged thread.

Thread Shear: Thread shear refers to the stripping off of threads from the pin and/or box.

Generally speaking, shear failure of most threads under axial load does not occur. In most cases, failure of V-shape threads is caused by jumpout or occasionally, by fracture of the pipe in the last engaged threads. Square threads provide a high strength connection and failure is usually caused by fracture in the pipe near the last engaged thread. Many proprietary connections use a modified buttress thread and some use a negative flank angle to increase the joint strength.

In addition to its function of supporting tension and other loads, a joint must also prevent the leakage of the fluids or gases which the pipe must contain or exclude. Consequently, the interface pressure between the mating threads in a joint must be sufficiently large to obtain proper mating and sealing. This is accomplished by thread interference, metal to metal seal, resilient ring or combination seals.

Thread Interference: Sealing between the threads is achieved by having the thread members tapered and applying a makeup torque sufficient to wedge the pin and box together and cause interference between the thread elements. Gaps between the roots and crests and between the flanks of the mating surfaces, which are required to allow for machining tolerance, are plugged by a thread compound. The reliability of these joints is, therefore, related to the makeup torque and the gravity of the thread compound. Excessive makeup or insufficient makeup can both be harmful to the sealing properties of joints. The need for excessive makeup torque to generate high pressure often causes yielding of the joint.

Metal-to-Metal Seal: There are two types of metal-to-metal seal: radial and shoulder. Radial is usually used as the primary seal and the shoulder as the backup seal. A radial seal generally occurs between flanks and between the crests and roots as a result of: pressure due to thread interference created by makeup torque, pressure due to the radial component of the stress created by internal pressure and pressure due to the torque created by the negative flank angle (Fig. 1.8). Shoulder sealing occurs as a result of pressure from thread interference, which is directly related to the torque imparted during the joint makeup. Low makeup torque may provide insufficient bearing pressure, whereas high makeup torque can plastically deform the sealing surface (Fig. 1.8(c)).

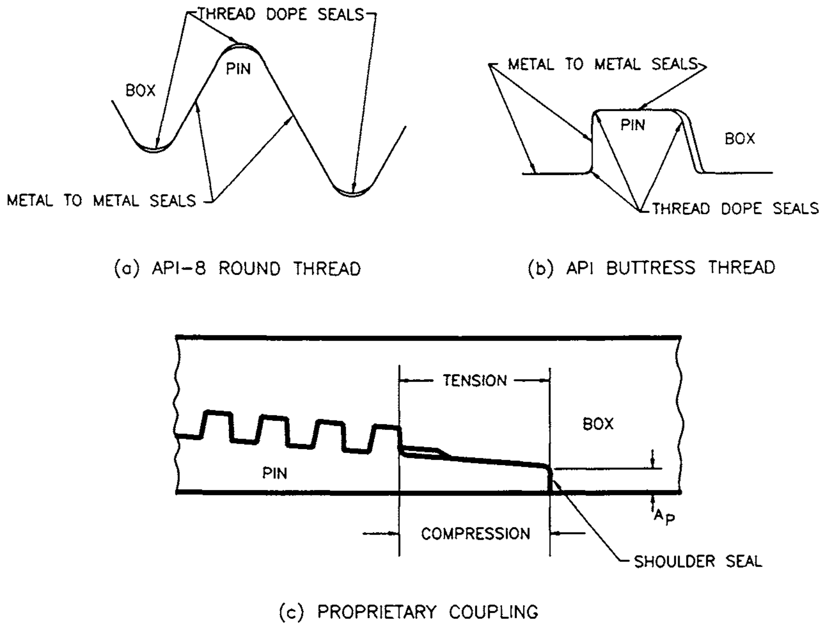

Fig. 1.8: Metal-to-metal seal: (a) API 8-Round thread, (b) API Buttress thread, (c) proprietary coupling. (After Rawlins, 1984.)

Resilient Rings: Resilient rings are used to provide additional means of plugging the gaps between the roots and crests. Use of these rings can upgrade the standard connections by providing sealing above the safe rating that could be applied to connections without the rings. Their use, however, reduces the strength of the joint and increases the hoop (circumferential) stress.

Combination Seal: A combination of two or more techniques can be used to increase the sealing reliability. The interdependence of these seals, however, can result in a less effective overall seal. For example, the high thread interference needed to seal high pressure will decrease the bearing pressure of the metal-to-metal seal. Similarly, the galling effect resulting from the use of a resilient ring may make the metal-to-metal seal ineffective (Fig. 1.9).

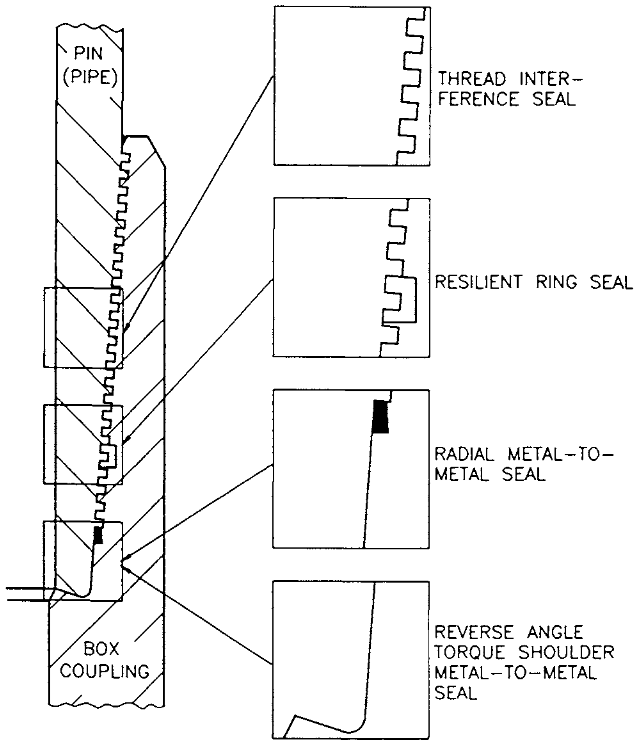

Fig. 1.9: Combination seals. (After Biegler, 1984.)

1.4.2 API Couplings

The API provides specifications for three types of casing couplings: round thread, buttress thread and extreme-line coupling.

API Round Thread Coupling

Eight API Round threads with a taper of $\frac{3}{4}$ in./ft are cut per inch on diameter for all pipe sizes. The API Round thread has a V-shape with an included angle of 60° (Fig. 1.10), and thus the thread roots and crests are truncated with a radius. When the crest of one thread is mated against the root of another, there exists a clearance of approximately 0.003-in. which provides a leak path. In practice, a special thread compound is used when making up two joints to prevent leakage. Pressure created by the flank interface due to the makeup torque provides an additional seal. This pressure must be greater than the pressure to be contained.

API Round thread couplings are of two types: short thread coupling (STC) and long thread coupling (LTC). Both STC and LTC threads are weaker than the pipe body and are internally threaded. The LTC is capable of transmitting a higher axial load than the STC.

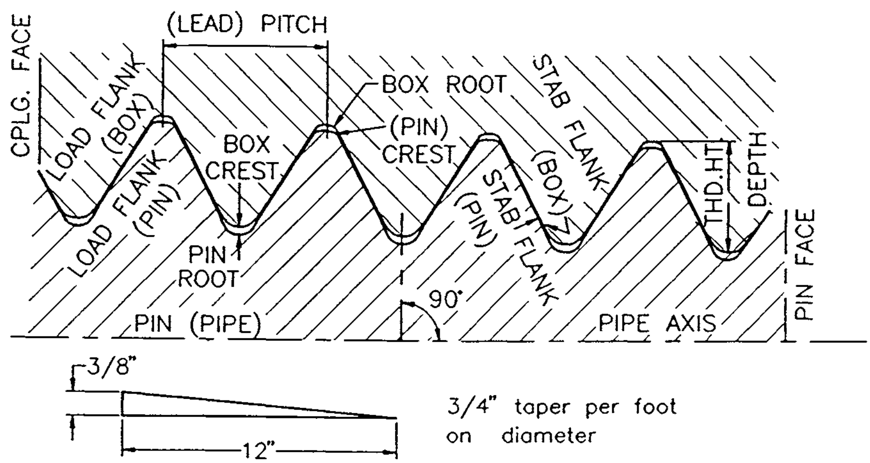

Fig. 1.10: Round thread casing configuration. (After API RP 5B1, 1988.)

API Buttress Thread Coupling

A cross-section of a API Buttress coupling is presented in Fig. 1.11. Five threads are cut in one inch on the pipe diameter and the thread taper is $\frac{3}{4}$ in./ft for casing sizes up to $7\frac{5}{8}$ in. and 1 in./ft for sizes 16 in. or larger. Long coupling, square shape and thread run-out allow the API Buttress coupling to transmit higher axial load than API Round thread. The API Buttress couplings, however, depend on similar types of seal to the API Round threads. Special thread compounds are used to fill the clearance between the flanks and other meeting parts of the threads. Seals are also provided by pressure at the flanks, roots and crests during the making of a connection. In this case, tension has little effect on sealing, whereas compression load could separate the pressure flanks causing a spiral clearance between the pressure flanks and thereby permitting a leak. Frequent changes in load from tension to neutral to compression causes leaks in steam injection wells equipped with API Buttress couplings.

A modified buttress thread profile is cut on a taper in some proprietary connections to provide additional sealing. For example, in a Vallourec VAM casing coupling, the thread crest and roots are flat and parallel to the cone. Flanks are 3° and 10° to the vertical of the pipe axis, as shown in Fig. 1.12, and 5 threads per inch are on the axis of the pipe. Double metal-to-metal seals are provided at the pin end by incorporating a reverse shoulder at the internal shoulder (Fig. 1.12), which is resistant to high torque and allows non-turbulent flow of fluid.

Metal-to-metal seals, at the internal shoulder of VAM coupling, are affected most by the change in tension and compression in the pipe. When the makeup torque is applied, the internal shoulder is locked into the coupling, thereby creating tension in the box and compression in the pin. If tensile load is applied to the connection, the box will be elongated further and the compression in the pin will

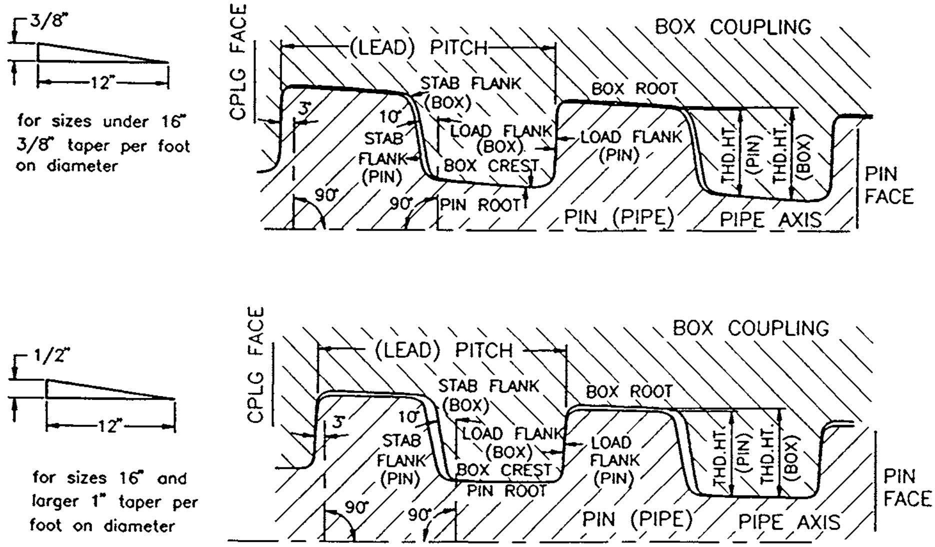

Fig. 1.11: (a) API Buttress thread configuration for $13\frac{3}{8}$ in. outside diameter and smaller casing; (b) API Buttress thread configuration for 16 in. outside diameter and larger casing. (After API RP 5B1, 1988.)

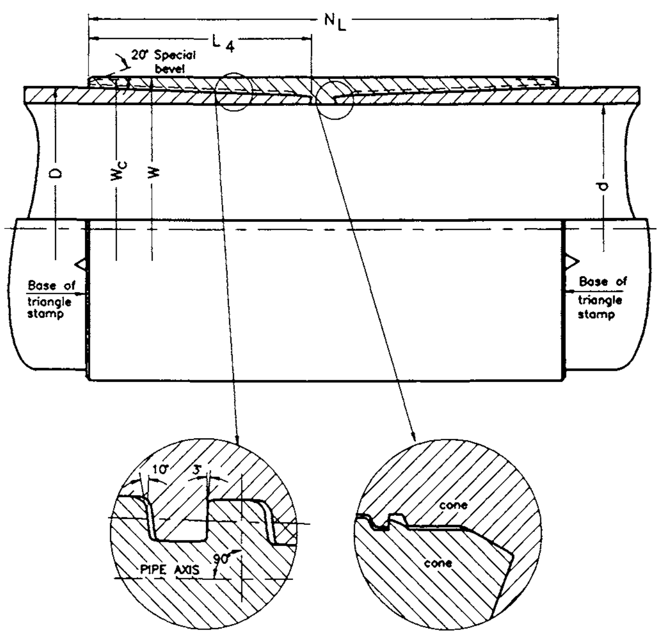

Fig. 1.12: Vallourec VAM casing coupling. (After Rabia, 1987; courtesy of Graham & Trotman)

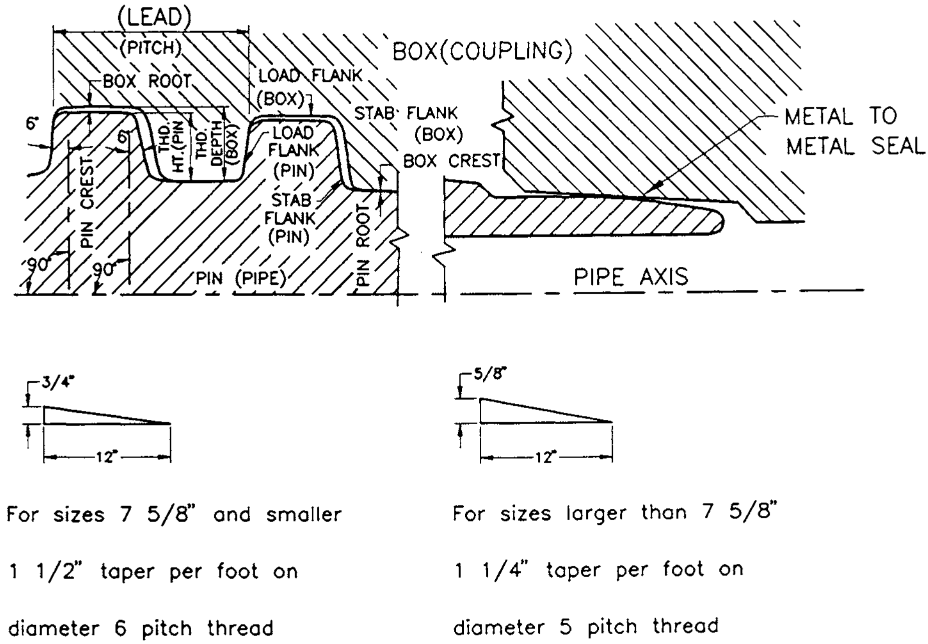

Fig. 1.13: API Extreme-line casing thread configuration. (After API RP 5B1, 1988.)

be reduced due to the added load. Should the tensile load exceed the critical value, the shoulders may separate.

API Extreme-line Thread Coupling

API Extreme-line coupling differs from API Round thread and API Buttress thread couplings in that it is an integral joint, i.e., the box is machined into the pipe wall. With integral connectors, casing is made internally and externally upset to compensate for the loss of wall thickness due to threading. The thread profile is trapezodial and additional metal-to-metal seal is provided at the pin end and external shoulder. As a result, API Extreme-line couplings do not require any sealing compound, although the compound is still necessary for lubrication. The metal-to-metal seal at the external shoulder of the pin is affected in the same way as VAM coupling when axial load is applied.

In an API Extreme-line coupling, 6 threads per inch are cut on pipe sizes of 5 in. to $7\frac{5}{8}$ in. with $1\frac{1}{2}$ in./ft of taper and 5 threads per inch are cut on pipe sizes of $8\frac{5}{8}$ in. to $10\frac{3}{4}$ in. with $1\frac{1}{4}$ in./ft of taper. Figure 1.13 shows different design features of API Extreme-line coupling.

1.4.3 Proprietry Couplings

In recent years, many proprietary couplings with premium design features have been developed to meet special drilling and production requirements. Some of these features are listed below.

Flush Joints: Flush joints are used to provide maximal annular clearance in order to avoid tight spots and to improve the cement bond.

Smooth Bores: Smooth bores through connectors are necessary to avoid turbulent flow of fluid.

Fast Makeup Threads: Fast makeup threads are designed to facilitate fast makeup and reduce the tendency to cross-thread.

Metal-to-Metal Seals: Multiple metal-to-metal seals are designed to provide improved joint strength and pressure containment.

Multiple Shoulders: Use of multiple shoulders can provide improved sealing characteristics with adequate torque and compressive strength.

Special Tooth Form: Special tooth form, e.g., a squarer shape with negative flank angle provide improved joint strength and sealing characteristics.

Resilient Rings: If resilient rings are correctly designed, they can serve as secondary pressure seals in corrosive and high-temperature environments.

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