CHAPTER-3

DRILL STRING and CASING

The drill string is an important part of the rotary drilling process. It is the connection between the rig and the drill bit. Although the drill string is often a source of problems such as washouts, twist-offs, and collapse failures, it is seldom designed to prevent these problems from occurring. In many cases, a few minutes of drill string design work could prevent most of the problems.

Purposes and Components:

The drill string serves several general purposes, including the following:

- provide a fluid conduit from the rig to the bit
- impart rotary motion to the drill bit
- allow weight to be set on the bit
- lower and raise the bit in the well

In addition, the drill string may serve some of the following specialized services:

a- provide some stability to the bottom-hole assembly to minimize vibration and bit jumping,
b- allow formation fluid and pressure testing through the drill string,
c- permit through-pipe formation evaluation when logging tools cannot be run in the open hole,

The drill string consists primarily of the drill pipe and bottom-hole assembly (BHA). The drill pipe section contains conventional drill pipe, heavyweight pipe and occasionally a reamer. The BHA may contain the following items:

- drill collars (several types and sizes)
- stabilizers
- jars
- reamers
- shock subs
- bit sub

Special tools in the BHA or drill pipe may include monitor-while-drilling (MWD) tools, drill stem testing tools, and junk baskets.
**Drill Pipe:**

The longest section of the drill string is the drill pipe. The BHA is usually no longer than 1,000 ft. Each joint of drill pipe includes the tube body and the tool joint, which connects the sections of drill pipe. Although aluminum drill pipe is sometimes used in special projects, it will not be presented in this section. However, it does have important applications in remote areas where airfreight is required and where otherwise the rig would have insufficient hoisting capacity. Drill pipe is available in several sizes and weights (Table 3-1). Common sizes include the following:

- 3 ½ in.-13.30 lb/ft nominal
- 4 ½ in.-16.60 lb/ft nominal
- 5 in. -19.50 lb/ft nominal

Various types of tool joints may increase the average weight per foot, i.e., 16.60-18.60 lb/ft for 4.5-in. pipe. However, it is still termed as 16.60-lb/ft pipe.

The grade of drill pipe describes the minimum yield strength of the pipe. This value is important because it is used in burst, collapse, and tension calculations. Common grades are as follows:

**Table 3-1 Common Grades of Drill Pipes**

<table>
<thead>
<tr>
<th>Letter Designation</th>
<th>Alternate Designation</th>
<th>Yield Strength (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>D</td>
<td>D-55</td>
<td>55000</td>
</tr>
<tr>
<td>E</td>
<td>E-75</td>
<td>75000</td>
</tr>
<tr>
<td>X</td>
<td>X-95</td>
<td>95000</td>
</tr>
<tr>
<td>G</td>
<td>G-105</td>
<td>105000</td>
</tr>
<tr>
<td>S</td>
<td>S-135</td>
<td>135000</td>
</tr>
</tbody>
</table>

In most drill string design, the pipe grade will be increased for extra strength rather than increase the pipe weight. This approach differs somewhat from casing design. Drill pipe is unlike most other oil-field tubular, such as casing and tubing, because it is used in a worn condition. Casing and tubing are usually new when installed in the well. As a result “classes” are given to drill pipe to
account for wear. Therefore, drill pipe must be defined according to its nominal weight, grade and class.

The API has established guidelines given below:

**New** = No wear and has never been used.

**Premium** = Uniform wear and a minimum wall thickness of 80%.

**Class 2** = Allows drill pipe with a minimum wall thickness of 65% with all wear on one side so long as the cross-sectional area is the same as premium class; that is to say, based on not more than 20% uniform wall reduction.

**Class 3** = Allows drill pipe with a minimum wall thickness of 55% with all wear on one side.

Drill pipe classification is an important factor in drill string design and use since the amount and type of wear affect the pipe properties and strengths. Drill pipe is available in several length ranges:

**Table-3-2 Ranges of Drill Pipes**

<table>
<thead>
<tr>
<th>Range</th>
<th>Length, ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>18-22</td>
</tr>
<tr>
<td>2</td>
<td>27-30</td>
</tr>
<tr>
<td>3</td>
<td>38-40</td>
</tr>
</tbody>
</table>

**Heavy Weight Pipe:**

The use of heavy weight drill pipe in the drilling industry has become a widely accepted practice. The pipe is available in conventional drill pipe outer diameters. However, its increased wall thickness gives a body weight 2-3 times greater than regular drill pipe. Heavy weight drill pipe provides three major benefits to the user.

- Reduces drilling cost by virtually eliminating drill pipe failures in the transition zone.
- Significantly increases performance and depth capabilities of small rigs in shallow drilling areas through the case of handling and the replacement of some of the drill collars.
-Provides substantial savings in directional drilling costs by replacing the largest part of the drill-collar string, reducing down hole drilling torque, and decreasing tendencies to change direction.

Most heavy-wall drill pipe has an integral center upset acting as a centralizer and wear pad. It helps prevent excessive tube wear when run in compression. This pipe has less wall contact than drill collars and therefore reduces the chances of differential pipe sticking.

**Drill Collars:**

Drill collars are the predominant components of the bottom-hole assembly. Some of the functions of the collars are as follows:
- provide weight for the bit
- provide strength needed to run in compression
- minimize bit stability problems from vibrations, wobbling, and jumping
- minimize directional control problems by providing stiffness to the BHA

Proper selection of drill collars (and BHA) can prevent many drilling problems. Drill collars are available in many sizes and shapes, such as round, square, triangular, and spiral grooved. The most common types are round (slick) and spiral grooved. Large collars offer several advantages.

- fewer drill collars are needed for required weight
- fewer drill collar connections are required.
- less time is lost handling drill collars during trips
- factors governing good bit performance favor close fitting stiff members
- straighter holes can be drilled
**Drill-Collar Selection:**

The drill collars are the first section of the drill string to be designed. The collars length and size affect the type of drill pipe that must be used. Drill-collar selection is usually based on:

- buckling considerations in the lower sections of the drill string when weight is set on the bit or,
- using a sufficient amount of drill collars to avoid running the drill pipe in compression.

The design approaches that satisfy these design criteria are the buoyancy factor method and the pressure-area method, respectively. The drilling engineer must evaluate these approaches and make some design decisions since significantly different amounts of drill collars are required with each method.

**Buoyancy Factor Method**

Drill string buckling is a potential problem that must be avoided. If buckling occurs, stresses in the pipe and tool joints will cause pipe failure. The greatest potential for drill pipe buckling normally occurs when weight is slacked off on the bit.

Lubinsky et al. have studied buckling in oil-field tubing, casing, and drill-strings. They proved that buckling will not occur if bit weights in excess of the buoyed
collar weight are not used. Most current industry practices adhere to this buoyed-weight concept. The buoyed weight of the drill collars is the amount of weight that must be supported by the derrick when collars are run in the hole. This load is always less than the in-air weight if mud is used in the well. For example, collars that weigh 147 lb/ft while sitting on the pipe racks may have a buoyed weight of 113 lb/ft in 15.0-lb/gal mud. Several methods are commonly used to determine the buoyed weight of the drill collars:

- lower the drill collars (bottom-hole assembly) into the hole and read the weight indicator (less the hook weight)
- calculate the weight of the displaced mud and subtract from the in-air collar weight
- multiply the in-air weight with a buoyancy factor that is dependent on mud weight

The widely used buoyancy factor is calculated from the following equation:

\[ BF = 1 - \left( \frac{MW}{65.5} \right) \]

where, \( BF \) = buoyancy factor, dimensionless; \( MW \) = mud weight (lb/gal), and 65.5 = weight of a gallon of steel, lb/gal.

The available bit weight (ABW) with the buoyancy factor method is the buoyed weight of the drill collars (bottom-hole assembly) in the mud to be used. It is calculated as follows:
\[ ABW = (\text{in-air collar weight}) \times (\text{buoyancy factor}) \]

The required collar length to achieve an arbitrary ABW can be calculated as follows:

\[ \text{Length} = \frac{\text{ABW}}{(\text{BF}) (\text{CW})} \]

where, \( ABW \) = desired available bit weight, lb; \( BF \) = buoyant factor, dimensionless; \( CW \) = collar weight (in-air), lb/ft; and length = required collar length to achieve the desired ABW, ft

Operators usually run 10-15% more collars that ABW would indicate. This gives a safety margin and keeps the buoyancy-neutral point within the collars when unforeseen forces (bounce, hole friction, deviation) move the buckling point up into the weaker drill pipe section.

**Pressure-Area Method**

Drill pipe tool joints are manufactured to be run in tension. According to industry guidelines relating to drill pipe, they should not be run in compression. Therefore, some industry operators design the drill-string so only the drill collars are subjected to compression loading.

A drill string tension analysis determines the amount of weight that can be put on the bit without causing the tension-compression neutral point to move into the drill pipe. The tension neutral point, which is different from Lubinski’s neutral point of buckling, is the depth of zero tension loading. The different
definitions for the term "neutral point" have caused significant controversy in the industry. A tension analysis includes the pipe and collar weights as well as the vertical forces acting on the pipe. The vertical forces are calculated as the hydrostatic pressure at the depth of interest acting on the cross-sectional area of the pipe. The vertical forces, termed buoyant forces, are usually calculated at the bottom and top of the collars.

The pressure-area method usually requires a larger section of drill collars to achieve comparable ABW than the buoyancy factor method. In addition, the pressure-area method is depth dependent since the hydrostatic pressures are a function of the well depth as well as the mud weight.

**Example 3-1** Use the following data to determine the available bit weight with the pressure area and buoyancy force methods (See Figure 3-1):

- **Well depth**: 13500 ft; **MW** = 14.8 lb/gal; **Drill Collars**: 8 x 3 inch 540 ft; **Drill Pipe**: 5 x 4.276 inch 19.50 lb/ft

**Solution:**

**Buoyancy Force Method:**

- The collar weight on a lb/ft basis is computed as,

  \[
  \text{Weight (lb/ft)} = \frac{\pi}{4} \left[ \left( \frac{8^2 - 3^2}{0.2945} \right) \right] = 147 \text{ lb/ft}
  \]

- Calculate the collar weight in air,

  \[147 \text{ lb/ft} \times 540 \text{ ft} = 79380 \text{ lb}\]
Determine the buoyancy factor,

\[ BF = 1 - \left( \frac{MW}{65.5} \right) = 1 - \left( \frac{14.8}{65.5} \right) = 0.774 \]

- The available bit weight (ABW) with the buoyancy factor is calculated as the product of the buoyancy factor (BF) and the collar weight.

\[ ABW = BF \times 79380 = 61440 \text{ lb} \]

*Pressure Area Method*

- Use the following figure to calculate the buoyant forces for the pressure-area method.

\[ BF_1 = -P \times A \]

\[ BF_1 = -(0.052 \times 14.8 \text{ lb/gal} \times 13500 \text{ ft}) \left[ \frac{\pi}{4} \left( 8^2 - 3^2 \right) \right] \]

\[ BF_1 = -(10389 \text{ psi}) \left( 43.10 \text{ inch}^2 \right) \]

\[ BF_1 = -448726 \text{ lb} \]

\[ BF_2 = (0.052 \times 14.8 \text{ lb/gal} \times 12960 \text{ ft}) \left[ \frac{\pi}{4} \left( 8^2 - 5^2 \right) + \frac{\pi}{4} \left( 4.276^2 - 3^2 \right) \right] \]

\[ BF_2 = (9974 \text{ psi}) \left( 37.92 \text{ inch}^2 \right) \]

\[ BF_2 = +378214 \text{ lb} \]

- The ABW is the sum of buoyant forces acting on the collars and the collar weight.

\[ ABW = BF_1 + BF_2 \text{ collar weight} \]

\[ ABW = -448726 \text{ lb} + 378214 \text{ lb} + 79380 \text{ lb} \]

\[ ABW = 8868 \text{ lb} \]
Drill Pipe Selection

Drill pipe is used for several purposes, including providing a fluid conduit for pumping drilling mud, imparting rotary motion to the drill bit, and conducting special operations such as drill stem testing and squeeze cementing. The
controlling criteria for drill string design are collapse, tension, slip crushing and
dogleg severity. Collapse and tension are used to select weights, grades and
couplings. Typically, higher-strength pipe is required in the lower sections of the
string for collapse resistance, while tension dictates the higher strength pipe at
the top of the well.

**Drill String Design:**

The following design criteria will be used to select a suitable drill string: (a) tension, (b) collapse, (c) shock loading and (d) torsion.

**Tension:**

Prior to deriving any equation, it should be observed that only submerged
weights are considered, since all immersed bodies suffer from lifting or
buoyancy forces. Buoyancy force reduces the total weight of the body and its
magnitude is dependent on fluid density. The total weight, \( P \), carried by the top
joint of drill pipe is given by:

\[
P = (\text{weight of drill pipe in mud}) + (\text{weight of drill collars in mud})
\]

\[
P = [(L_{dp} \times W_{dp} - L_{dc} \times W_{dc})] \times BF
\]

where; \( L_{dp} \) = length of drill pipe; \( W_{dp} \) = weight of drill pipe per unit length; \( L_{dc} \) =
length of drill collars; \( W_{dc} \) = weight of drill collars per unit length and \( BF \) =
buoyancy factor.

Drill pipe strength is expressed in terms of yield strength. This is
defined as the load at which deformation occurs. Under all conditions of loading,
steel elongates initially linearly in relation to the applied load until the elastic limit is reached. Up to this limit, removal of applied load results in the steel pipe recovering its original dimensions. Loading a steel pipe beyond the elastic limit induces deformation which cannot be recovered, even after the load is removed. This deformation is described as yield and results in a reduction in pipe strength. Drill string design is never based on the tabulated yield strength value but, instead on 90% of the yield strength to provide an added safety in the resulting design. Thus, maximum tensile design load,

\[ P_a = P_t \times 0.9 \]

where; \( P_t \) = drill pipe yield strength.

The difference between \( P_a \) and \( P \) gives the margin of over pull (MOP)

\[ MOP = P_a - P \]

The design values of MOP normally range from 50000-100000 lb.

Actual safety factor gives the ratio of \( P_a / P \).

\[ SF = \frac{P_a}{P} = \frac{(P_t \times 0.9)}{[((L_{dp} \times W_{dp} - L_{dc} \times W_{dc})) \times BF]} \]

Dynamic loading, which arises from arresting the drill pipe by slips must be considered.

\[ L_{dp} = \frac{((P_t \times 0.9 - MOP)}{[((W_{dp} \times BF))] - (W_{dc} / W_{dp}) \times L_{dc}} \]

The above equation can also be expressed in terms of MOP instead of SF term:

\[ L_{dp} = \frac{((P_t \times 0.9 - MOP)}{[(W_{dp} \times BF)]} - (W_{dc} / W_{dp}) \times L_{dc} \]

The term \( L_{dp} \) is sometimes expressed as \( L_{max} \) to refer to the maximum length of
a given grade of drill pipe which can be selected for a given loading situation.

The above equations can also be used to design a tapered string, consisting of different grades and sizes of drill pipe. In this case the lightest available grade is first considered and the maximum useable length selected as a bottom section. Successive heavy grades are then considered in turn to determine the useable length from each grade along the hole depth.

**Collapse:**

Collapse pressure may be defined as the external pressure required causing yielding of drill pipe or casing. In normal drilling operations the mud columns inside and outside the drill pipe are both equal in height and are of the same density. This results in zero differential pressure across the pipe body and, in turn, zero collapse pressure on the drill pipe. In some cases, as in drill stem testing (DST), the drill pipe is run partially full, to reduce the hydrostatic pressure exerted against the formation. This is done to encourage formation fluids to flow into the well bore, which is the object of the test. Once the well flows, the collapsing effects are small, as the drill pipe is now full of fluids.

Thus, maximum differential pressure, $\Delta P$, across the drill pipe exists prior to the opening of the DST tool, and can be calculated as follows:

$$\Delta P = \left( \frac{L \rho_1}{144} \right) - \left( \frac{(L - Y) \times \rho_2}{144} \right)$$

where: $Y =$ depth to fluid inside drill pipe; $L =$ total depth of well (ft); $\rho_1 =$ fluid density outside the drill pipe (lb/ft$^3$); $\rho_2 =$ fluid density inside the drill pipe
When densities are expressed in ppg, the above equation becomes,

\[ \Delta P = \left( \frac{L \rho_1}{19.251} \right) - \left[ (L - Y) \times \frac{\rho_2}{19.251} \right] \]

Other variations of the above equation include the following:

(a) Drill pipe is completely empty, \( Y = 0, \rho_2 = 0 \)

\[ \Delta P = \left( \frac{L \rho_1}{144} \right) \]

(b) Fluid density inside drill pipe is the same as that outside drill pipes:

i.e. \( \rho_1 = \rho_2 = \rho \)

\[ \Delta P = \left( \frac{Y \rho}{144} \right) \]

where, \( \rho \) = density of mud (lb/ft\(^3\))

Once the collapsing pressure, \( \Delta P \), is calculated, it can then be compared with the theoretical collapse resistance of the pipe. A safety factor in collapse can be determined as follows:

\[ SF = \frac{\text{collapse resistance}}{\text{collapse pressure}} \]

Normally drillpipe is under tension resulting from its own weight and the weight of drill collars. The combined loading of tension and collapse is described as biaxial loading. During biaxial loading, the drillpipe stretches and its collapse resistance of drillpipe can be determined as follows:

- Determine tensile stress at joint under consideration by dividing the tensile load by the pipe cross-sectional area.
- Determine the ratio between tensile stress and the average yield strength.

- Use necessary figure to determine the percent reduction in collapse resistance corresponding to the ratio calculated.

**Torsion:**

It can be shown that the drill pipe torsional yield strength when subjected to pure torsion is given by:

\[ Q = (0.096167 \ J \ Y_m / D) \]

where \( Q \) = minimum torsion yield strength (lb-ft); \( Y_m \) = minimum unit yield strength (psi); \( J \) = polar moment of inertia = \( \pi/32 \ (D^4 - d^4) \) for tubes = 0.098175\((D^4 - d^4)\); \( D \) = outside diameter (in), \( d \) = inside diameter (in).

When drill pipe is subjected to both torsion and tension, as is the case during drilling operations the above equation becomes:

\[ Q_t = (0.096167 \ J / D) \sqrt{Y_m^2 - (P^2 / A^2)} \]

where \( Q_t \) = minimum torsion yield strength under tension (lb-ft); \( J \) = polar moment of inertia = \( \pi/32 \ (D^4 - d^4) \) for tubes = 0.098175\((D^4 - d^4)\); \( D \) = outside diameter (in); \( d \) = inside diameter (in); \( Y_m \) = minimum unit yield strength (psi); \( P \) = total load in tension (lb); \( A \) = cross-sectional area (in²).
**Example 3-2** A drill string consists of 600 ft of $8^{1/4}$ in x $2^{13/16}$ in drill collars and the rest is a 5 in, 19.5 lbm/ft, Grade X95 drillpipe. If the required MOP is 100 000 lb and mud weight is 75 pcf (10 ppg), calculate the maximum depth of hole that can be drilled when;

(a) using new drill pipe and

(b) using Class 2 drill pipe having a yield strength ($P_t$) of 394600 lb.

**Solution:**

(a) Weight of drill collar per foot is;

$$A \times 1 \text{ ft} \times \rho_s = \pi / 4 \left[ (8^{1/4})^2 - (2^{13/16})^2 \right] \times 1 \text{ ft} \times 489.5 \times 1/144 = 160.6 \text{ lbm/ft}$$

where; $\rho_s$ = density of steel (489.5 lbm/ft) ; $A$ = cross-sectional area (in).

(weight of drill collar = 161 lbm/ft.)

$$L_{dp} = \frac{(P_t \times 0.9 - MOP) / [(W_{dp} \times BF)] - (W_{dc} / W_{dp}) \times L_{dc}}{[(P_t \times 0.9 - MOP) / [(W_{dp} \times BF)] - (W_{dc} / W_{dp}) \times L_{dc}}$$

$P_t$ = 501090 lb (Grade X95 new pipe)

$BF = 1 - (\rho_m / \rho_s) = 1 - (75 / 489.5) = 0.847$ and $MOP = 100000 \text{ lb}$

Therefore;

$$L_{dp} = \frac{(501090 \times 0.9 - 100000) / [19.5 \times 0.847] - (160.6 / 19.5) \times 600}{(501090 \times 0.9 - 100000) / [19.5 \times 0.847] - (160.6 / 19.5) \times 600}$$

$L_{dp} = 16309 \text{ ft}$

Therefore, maximum hole depth that can be drilled with a new drillpipe of Grade X-95 under the given loading condition is $16309 + 600 = 16909 \text{ ft}$
(b) Now Pt = 394600 lb

\[ L_{dp} = \frac{(P_t \times 0.9 - MOP) / [(W_{dp} \times BF)] - (W_{dc} / W_{dp}) \times L_{dc}}{19.5 \times 0.847} \]

\[ L_{dp} = \frac{(394600 \times 0.9 - 100000) / [19.5 \times 0.847]}{160.6 / 19.5} \times 600 \]

\[ L_{dp} = 10506 \text{ ft} \]

Maximum hole depth = 10506 + 600 = 11106 ft

**Example 3-3** If 10000 ft of the drillpipe in Example-1 is used, determine the maximum collapse pressure that can be encountered and the resulting safety factor. The mud density is 75 pcf (10 ppg). If the fluid level inside the drillpipe drops to 6000 ft below the rotary table, determine the new safety factor in collapse.

**Solution:**

a) Maximum collapse pressure, \( \Delta P \), occurs when the drillpipe is 100% empty.

\[ \Delta P = \frac{L \rho_m}{144} \]

\[ \Delta P = \frac{(10000 \times 75)}{144} = 5208 \text{ psi} \]

Collapse resistance of new pipe of Grade X95 is 12010 psi.

\[ SF = \frac{12010}{5208} = 2.3 \]

(b) When the mud level drops to 6000 ft below the surface;

\[ \Delta P = \frac{L \rho_m}{144} \]

\[ \Delta P = \frac{(6000 \times 75)}{144} = 3125 \text{ psi} \]

\[ SF = \frac{12010}{3125} = 3.8 \]
Example-3-4 A drill string consists of 10000 ft of drill pipe and a length of drill collars weighting 80000 lb. The drill pipe is 5 in. OD, 19.5 lb, Grade S 135, premium class.

(a) Determine the actual collapse resistance of the bottom joint of drill pipe

(b) Determine the safety factor in collapse. (Assume collapse resistance = 10050 psi and mud weight = 75 lb / ft$^3$.

**Solution:**

For a 5 in. OD new drill pipe, the nominal ID is 4.276 in. (thickness = 0.376 in.).

For a premium drill pipe, only 80% of the pipe thickness remains. Thus reduced wall thickness for premium pipe is = 0.8 x 0.362 = 0.2896 inch and reduced OD for a premium pipe;

Reduced OD = nominal ID + 2 x (premium thickness)

Reduced OD = 4.276 + 2 x (0.2896)

Reduced OD = 4.8552 inch

Cross sectional area (CSA) of premium pipe = $\pi / 4 (OD^2 - ID^2)$

Cross sectional area of premium pipe = $\pi / 4 (4.8552^2 - 4.276^2)$

Cross sectional area of premium pipe = 4.1538 inch$^2$

Tensile stress at bottom joint of drill pipe = tensile load

Tensile stress at bottom joint of drill pipe = (weight of drill collars / CSA)

Tensile stress at bottom joint of drill pipe = 80000 lb / 4.1538 inch$^2$
Tensile stress at bottom joint of drill pipe = **19259 psi**

From the figure given below; a tensile ratio of **13.3%** reduces the nominal collapse resistance to **53%**.

(a) **Collapse resist. of bottom joint of drill pipe = 0.93 \times \text{collapse resist. under zero load}**

\[ \text{Collapse resist. of bottom joint of drill pipe} = 0.93 \times 10050 = 9347 \text{ psi} \]

(b) **SF = (collapse resistance / collapse pressure)**

For worst conditions assume drill pipe to be 100% empty. Hence;

\[ \text{Collapse pressure} = \frac{75 \times 10000}{144} = 5208 \text{ psi} \]

\[ SF = \frac{9347}{5208} = 1.8 \]
Casing

Drilling environments often require several casing strings in order to reach the total desired depth. Some of the strings are as follows (Figure 3-1).

- drive or structural
- conductor
- surface
- intermediate (also known as protection pipe)
- liners
- production (also known as an oil string)
- tubing

**Drive Pipe or Conductor Casing:**

The first string run or placed in the well is usually the drive pipe or conductor casing. The normal depth range is from 100-300 ft. In soft-rock areas the pipe is hammered into the ground with large diesel hammer. Hard-rock areas require that a large diameter shallow hole be drilled before running and cementing the well. A primary purpose of this string of pipe is to provide a fluid conduit from the bit to the surface. An additional function of this string of pipe is to minimize hole-caving problems.

**Structural Casing:**

Drilling conditions will require that an additional string of casing be run between the drive pipe and surface casing. Typical depth range from 600-1000
Purpose of this pipe includes solving additional lost circulation or hole caving problems and minimizing kick problems from shallow gas zones.

**Surface Casing:**

Many purposes exist for running surface casing, including:

- cover fresh water sands
- maintain hole integrity by preventing caving
- minimize lost circulation into shallow-permeable zones
- cover weak zones
- provide a means for attaching the blowout preventers
- support the weight of all casing strings (except liners) run below the surface pipe.
**Intermediate Casing:**

The primary applications of intermediate casing involve abnormally high formation pressures. Since higher mud weights are required to control these pressures, the shallower weak formations must be protected to prevent lost circulation or stuck pipe. It is used to isolate salt zones or zones those cause hole problems, such as heaving and sloughing shales.

**Liners:**

Drilling liners are used for the same purpose of intermediate casing. Instead of running the pipe to the surface, an abbreviated string is used from the bottom of the hole to a shallower depth inside the intermediate pipe. Usually the overlap between the two strings is **300-500 ft**. Drilling liners are used
frequently as a cost-effective method to attain pressure or fracture gradient control without the expense of running a string to the surface. When a liner is used, the upper exposed casing, usually intermediate pipe, must be evaluated with respect to burst and collapse pressures for drilling the open hole below the liner.

**Production Casing:**

The production casing is often called the oil string. The pipe may be set at a depth slightly above, or below the pay zone. The pipe has the following purposes:

- isolate the producing zone from the other formations.

- provide a work shaft of a known diameter to the pay zone.

- protect the producing tubing equipment.

**Casing Physical Properties**

The physical properties of oil-field tubular goods include grade, pressure, resistance, drift diameter and weight.

**Grade:**

The pipe grade is the designation that defines the pipe's yield strength and certain special characteristics. The grade usually consists of a letter and a 2 or 3 digit number such as N-80. As the letter proceeds, the pipe increases in yield strength. N-80 has greater yield strength than H-40. The numerical code indicates the minimum yield strength of 80,000 psi. The average yield strength is usually 10,000 psi greater than the minimum yield, 90,000 psi for N-80 pipe. The minimum value is used in burst and collapse resistance calculations, whereas the average is used for biaxial evaluation. C pipe is a controlled yield pipe used primarily in environments.
**Weight:**

The pipe weight is usually defined in pounds per foot. The calculated weights, as defined by the API, are determined by the following formula.

\[ W_L = (W_{pc} L) + e_w \]

- \( W_L \) = calculated weight of a pipe of length \( L \), lb
- \( W_{pc} \) = plain-end weight, lb/ft
- \( L \) = length of pipe, ft
- \( e_w \) = weight gain or loss due to end finishing, lb

The cross-sectional area of the pipe can be approximated from the pipe weight:

\[ A_p = 0.29 \ W_{pc} \]

- \( A_p \) = cross-sectional area, square-inch

**Range:**

Pipe range is a value for approximating the length of a section of pipe. Normal range sizes are 1, 2 or 3.

**Diameter:**

The drilling engineer must consider three types of diameter data when planning the tubular program. These are outer, inner and drift diameter.

**Burst:**

The burst rating of the casing is the amount of internal pressure that the pipe can withstand prior to failure. The internal yield pressure for pipe is calculated from the following equation.

\[ P_B = 0.875 \left \{ \frac{(2Y_p t)}{OD} \right \} \]

- \( P_B \) = burst pressure rounded to the nearest 10 psi
- \( Y_p \) = specified minimum yield strength, psi
- \( t \) = nominal wall thickness, inch
- \( OD \) = nominal outside diameter, inch
Example-3-5:

Calculate the internal yield (burst) pressure for 26.40 lb/ft, N-80, 7.625 inch pipe. Assume it has a wall thickness (t) of 0.328 inch. Use the API minimum wall thickness factor of 0.875. Recalculate the results and use 95 % wall thickness.

Solution:

a) The internal yield stress (burst) is calculated as:

\[ P_B = 0.875 \left( \frac{2Y_p \cdot t}{OD} \right) \]

\[ P_B = 0.875 \left[ 2(80000 \text{ psi}) \cdot 0.328 \text{ inch} \right] / 7.625 \text{ inch} \]

\[ P = 6020 \text{ psi} \]

b) Recalculate the results with a 95 % wall thickness.

\[ P_B = 0.95 \left[ 2(80000 \text{ psi}) \cdot 0.328 \text{ inch} \right] / 7.625 \text{ inch} \]

\[ P = 6540 \text{ psi} \]

Example-3-6:

A drilling engineer must design a production casing string for sour gas service. The maximum anticipated surface pressure for the 5.5 inch OD pipe is 20800 psi. The engineer's company dictates that pipe used in sour service will not have yield strength greater than 90,000 psi. Determine the wall thickness requirements for the pipe. Use the yield strength of 90,000 psi and assume that the API tolerance of 87.5 % wall thickness. Round up the wall thickness to the nearest 1/8 inch.

\[ P_B = 0.875 \left[ \left( \frac{2Y_p \cdot t}{OD} \right) \right] \]

\[ 20800 = 0.875 \left[ 2 \left( 90000 \text{ psi} \right) \cdot t \right] / 5.5 \]

\[ t = 0.726 \text{ inch and nearest 1/8 is: } t = 0.750 \text{ inch} \]
**Collapse:**

Unlike internal yield resistance of the pipe, collapse resistance equations vary depending on the D/t ratio. The collapse resistance is separated into four categories.

a) yield strength collapse pressure,

b) plastic collapse

c) transition collapse,

d) elastic collapse

The D/t range must be evaluated and the proper equation must be selected. Formula factors must be used in collapse calculations. The yield strength collapse pressure is not a true collapse pressure, rather the external pressure ($P_{yp}$) that generates minimum yield stress ($Y_p$) on the inside wall of a tube.

$$P_{yp} = 2 \ Y_p \ [ \ ((D/t) - 1) / (D/t)^2 \ ]$$

The formula for yield strength collapse pressure is applicable for D/t values up to the value of D/t corresponding to the intersection with plastic collapse formula. The intersection is calculated as follows:

$$(D/t)_{yp} = \sqrt{ \ (A-2)^2 + 8 \ (B-(C / Yp)) \ + \ (A - 2)) / \ [ \ 2 \ (B + C/Yp)\ ]}$$

The applicable D/t ratios for yield strength collapse are given in Table.

The minimum collapse pressure for the plastic range of collapse ($P_p$) is:

$$P_p = Y_p \ [ \ (A \ / \ (D/t)) - B \ ] - C$$

The formula for minimum plastic collapse pressure is applicable for D/t values ranging from ($D/t)_pt$ to the intersection for ($D/t)_t$, transition collapse pressure. Values for ($D/t)_pt$ are calculated by means of:

$$(D/t)_{pt} = [Y_p \ (A-F)] \ / \ [C + Y_p \ (B-G)]$$
Example-3-7:

An engineer must calculate the collapse rating for the following section of pipe. Using the API tables and equations, calculate the collapse pressure to the nearest 10 psi.

Pipe diameter: 9.625 inch, Wall thickness: 0.472 inch

Grade: N-80, Weight: 47 lb/ft

Solution:

1-Determine the D/t ratio:

\[ D/t = \frac{9.625 \text{ inch}}{0.472 \text{ inch}} \]

\[ D = 20.392 \]

From Table:

\[ A = 3.071; \quad B = 0.0667; \quad C = 1955 \]

\[ P_p = Y_p \left[ \frac{A}{D/t} - B \right] - C \]

\[ P_p = 80000 \left[ \frac{3.071}{20.392} \right] - 0.0667 - 1955 \]

\[ P_p = 4756 \text{ psi} \]

\[ P_p = 4750 - 4760 \text{ psi} \]

The minimum collapse pressure for the plastic to elastic transition zone \((P_t)\) is calculated:

\[ (P_t) = Y_p \left[ F \right] / (D/t) - G \]

Values for \((D/t)_{te}\) are calculated from the following equation:

\[ (D/t)_{te} = \frac{2 + (B/A)}{3 (B/A)} \]

The minimum collapse pressure for the elastic range of collapse is calculated as:

\[ P_e = 46.95 \times 10^6 \left/ \left( D/t \right) \left[ \left( D/t \right) - 1 \right]^2 \right. \]
Example-3-8

The collapse rating for 47.0 lb/ft, C-95 grade, 9.625 inch pipe must be calculated. The wall thickness is unknown. Use the API formulas and tables.

Solution:
1. Compute the cross-sectional area of the pipe.

\[ A_p = 0.29 \ W_p \]

\[ A_p = 0.29 \ (47 \ lb/ft) \]

\[ A_p = 13.63 \ \text{inch}^2 \]

2. Determine the wall thickness of the pipe from the cross-sectional area.

\[ A_p = \frac{\pi}{4} \ (OD^2 - ID^2) \]

\[ 13.63 = \frac{\pi}{4} \ (9.625^2 - ID^2) \]

\[ ID = 8.676 \ \text{inch} \]

\[ t = \frac{(OD - ID)}{2} \]

\[ t = \frac{(9.625 - 8.676)}{2} \]

\[ t = 0.4745 \ \text{inch} \]

3. D/t ratio is:

\[ D/t = \frac{9.625}{0.4745} = 20.284 \]

4. The formula for C-95 pipe with a D/t ratio of 20.284 is:

\[ A = 3.124 \quad B = 0.0743 \quad C = 2404 \]

\[ P_p = Y_p \left[ \frac{A}{(D/t)} - B \right] - C \]

\[ P_p = 95000 \left[ \frac{(3.124 / 20.284)}{0.0743} \right] - 2404 \]

\[ P_p = 5168 \ \text{psi} \]

Axial Stress:

An axial stress is calculated by modifying the yield stress to an axial stress equivalent grade:

\[ Y_{pa} = \sqrt{1 - 0.75 \left( \frac{S_A}{Y_p} \right)^2} - 0.5 \left( \frac{S_A}{Y_p} \right) \cdot Y_p \]
$S_A$ = axial stress, psi  
$Y_p$ = minimum yield strength, psi  
$Y_{PA}$ = yield strength of axial stress equivalent grade, psi  

**Example-3-9:**

The engineer must calculate the collapse pressure for the following pipe characteristics. **Size:** 7 inch OD; **Weight:** 26 lb/ft; **Grade:** P-110; $S_A$ = 11000 psi; $t$ = 0.362 inch

**Solution:**

1. Axial stress equivalent grade is:

   $Y_{PA} = \sqrt{1 - 0.75 (S_A / Y_p)^2} - 0.5 (S_A / Y_p) \cdot Y_p$

   $Y_{PA} = \sqrt{1 - 0.75 (11,000 / 110,000)^2} - 0.5 (11,000 / 110,000) \cdot 110,000$

   $Y_{PA} = 104,082$ psi

2. $D/t = ?$

   $D/t = 7 / 0.362 = 19.34$

3. $A = 3.181$  
   $B = 0.0819$  
   $C = 2852$

   $P_p = Y_p [ (A / (D/t)) - B ] - C$

   $P_p = 104082 [ (3.181 / (19.34)) - 0.0819 ] - 2852$

   $P_p = 5742$ psi

**Pipe Body Yield Strength:**

The pipe body strength is the axial load required to yield the pipe. It is the product of the cross-sectional area and the specified minimum yield strength for the particular grade of pipe.

$P_y = 0.7854 (OD^2 - ID^2) \cdot Y_p$
**Example-3-10:**

A section of 10.75 inch, 55 lb/ft N-80 casing is to be run into a well. It has a wall thickness of 0.495 inch. Determine the pipe body yield strength.

**Solution:**

1. The ID is computed from:
   \[ ID = OD - 2t \]
   \[ ID = 10.75 - 2(0.495) \]
   \[ ID = 9.76 \text{ inch} \]

2. The yield strength is calculated as:
   \[ P_y = 0.7854 (OD^2 - ID^2) Y_p \]
   \[ P_y = 0.7854 (10.75^2 - 9.76^2) 80,000 \]
   \[ P_y = 1,275,000 \text{ psi} \]