Casing String Design

GOPELC Internship Project

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Outline:

1. Introduction:

Casing a well is an indispensable process in oil/gas well drilling, and also the most expensive. Casing strings counterbalances the formation pressures as well as the mud and kick pressures to ensure that the borehole remains open for well intervention and future production.

Therefore, planning a detailed casing plan is important to ensure maximum well performance. The casing design depends on a lot of factors and constrains and are conducted by a team of petroleum engineers from different disciplines to ensure that it meets the well's planned drilling, completion, and production goals.

2. Definition:

Casing Strings are assemblies of steel pipes, typically 12 meters long, made from a variety of materials to suit a specific wellbore diameter and conditions. These strings are connected via threaded male/female couplings and are lowered and cemented in the wellbore. (Schlumberger Oilfield Glossary)

The Casing program is a vital for the safe and reliable drilling and completion of a production or injection well; it makes up the most expensive part of drilling the well reaching, 40% of the well's capital in some cases. Casing properties are a function of the weight of the casing, more weight = More Strength, but also more Weight = More Money, and thus a detailed study of the factors that affect the casing selection which make up the casing string in the well is crucial for feasible and durable well operations.

3. Function of Casing:

The functions of the casing string are summarized below:

- To provide a passage for the drill pipe, workover tools, logging tools and produced fluids.
- Provide support for weak formations, underground water reservoirs, pressured formations, and fractured formations.
- Isolate the well fluids and equipment from the fluids encountered in the formations.
- To provide suitable connection to the BOP and insure well control.

4. Types of Casing:

Different types of casing exist because of the necessity to seal off weak, unconsolidated, shaly, and pressurized formations that can be troublesome when drilling. Thus different sizes of casing are used in different borehole sections with different properties and grades forming an arrangement that gives a tapered shape to finish the well.

The types of casing are listed below:

- Conductor Casing (20’’-30’’): It is the first casing string, running form the surface to a shallow depth (normally 20-30 meters). The conductor’s main function is to support near surface unconsolidated formations, seal off shallow water zones, provide protection against shallow gas flows, provide a conduit for the drilling mud and protect the foundations of the platform in offshore operations. A BOP or a Diverter system can be mounted on this casing if the setting depth of the conductor is shallow.
  The conductor pipe is usually hammered in the ground, but also it could be placed in the hole after spudding the well and using a hole opener, in this case the conductor casing is cemented to the surface.
  The size of the conductor pipe varies according to the formation, as well as the depth of the pay zone. In the Middle East, conductor sizes are either 18 5/8 or 20 inches. Wells in the North Sea, however, use 26 to 30 inches.

- Surface Casing (13 3/8’’ – 20’’): The setting depth of this casing is chosen so that troublesome formations, thief zones, water sands, shallow HC zones and build-up sections of deviated wells may be protected. It is set after drilling and not hammered; in addition, is are cemented to the surface. The surface casing should be set in a competent rock, as hard limestone, which ensures that the formation at the casing shoe will not fracture at the high hydrostatic pressures encountered in later drilling operations. The BOP is installed after placing this casing to protect from shallow blowouts.

- Intermediate Casing (9 5/8’’-10 ¾’’): This casing is set in the transition zone between the surface casing and the production casing to seal off over pressurized zones as well as formations with swelling shales or salts. Good cementation of this casing is essential to ensure the isolation of the HC bearing zones and the shallow formation water. These casing are not usually cemented to the surface.

- Production Casing (4 ½’’- 7’’): This is the last section of the casing, it is run in the production zone to allow controlled inflow from the reservoir and provide zonal isolation to permit selective production in multi-zone production. This is the string through which the well is completed.

- Liners: It is a string of casing that does not reach the surface, instead it is hung on other casing strings via liner hangers. The liner in the intermediate casing acts as a production liner, thus the only necessary design criterion would be the collapse pressure since in is entrapped inside another casing.

  Liners have several advantages and disadvantages,
  Advantages: Reduce the weight landed on the well head, provide a Polished bore hole receptacle, improves completion flexibility.
  Disadvantages: Possible leak across a liner hanger, difficulty in obtaining a good primary cementation.

5. Casing Design

Casing Design involves the determination of the factors which influence the failure of the casing and the selection of the most suitable casing grades and weights for a specific operation, both safely and economically. The casing design also reflects the completion and production requirements of the well.

After the casing design has been conducted, the casing string should be able to withstand the expected internal, external, and tensional loads applied by the formations, fluids, and weight of casing itself to a given CSD. The subjection of the casing to other forces like bending, buckling, fatigue, corrosion, wear, and thermal stress should also be accounted for by including a safety factor in the design.

The incorrect casing design can result in disastrous consequences, placing human lives at risk and causing damage and loss of expensive equipment, the well, and eventually production from the reservoir. The risk of Blowouts may be magnified due to the improper casing, this could lead to a huge economic impact on the company and a huge footprint in the environment.

5.1- Data Collection:

Before starting the casing design, essential data must be collected from several sources, including: Geologists, Petrophysicists, Production engineers, Reservoir engineers, etc.

The data required is listed in the table below (table 1):

Table 1	
Data	Source
Formation Pressure (psi)	Offset Wells, Logs
Casing Setting Depth (ft)	Offset Wells,Kick Tolerence Calculations
Fracture Gradient (psi/ft)	Offset Wells, Logs, Calculation of Fracture Gradient
Mud Density (ppg)	Offset Wells, Logs, Calculation of Fracture Gradient
Mean Sea Water Level (ft)	
Available Casing Grades and Weights	Stock Status Reports, Casing Suppliers
Strength Properties (Burst, Collapse, Yield)	API or manufacturer's catalogues

Table 1. Data Required for Casing Design and their Sources.

Once the above data is obtained, it may be organized in the format given below (table 2) which would greatly heal in casing design calculations. (Rabiah)

Casing OD (in)	18 5/8''	13 3/8''	9 5/8''	7''
CASD TVD (ft)				
Casing Grade and Weight (lb/ft)				
ID (in)				
Drift Diameter (in)				
Coupling Type				
Collapse Strength (psi)				
Burst Strength (psi)				
Body Yield Strength (lbf x 1000)				
Connection Part Load (lbf x 1000)				
Mud Density to Drill for the Casing (ppg)				
Mud Density to Drill the Next Hole (ppg)				
Formation Pressure at next TD (psi)				
Fracture Gradient at Casing Steat (psi/ft)				

Table 2. Info. Arrangement for Casing Design.

5.2- Design Criteria:

Collapse, Burst, and Tension are the three basic forces that the casing string will be subjected to in the wellbore. Casing should be initially designed for these 3 forces and then refinements will be made on the selected grade and weight. The values of the 3 forces must be maintained under the casing strength properties.

In directional wells, wellbore pressures and tensile forces are calculated using the TVD. The casing lengths are first calculated as if the well is vertical. The lengths are then corrected with the hole angle.

The accuracy of the casing design depends greatly on the accuracy of the information collected (table 1).

5.2.1- Collapse Criterion:

Collapse pressure originates from the mud pressure used to drill the hole in which the casing is being set where it acts on the outer walls of the casing. The hydrostatic pressure of the mud increases with depth and thus <u>the collapse pressure is zero at surface an maximum at the bottom of hole.</u>

Collapse pressure calculations should also account for internal pressure; thus it is calculated from the following equation:

Collapse Pressure (C) = External Pressure – Internal Pressure (1)

The following simplified procedure is recently used for casing collapse design:

1- Casing is assumed empty due to lost circulation at CSD or at TD of next hole, see fig.1.
2- Internal pressure inside the casing is zero.
3- External pressure is caused by the mud in which casing was run in.
4- No cement is present outside the casing.

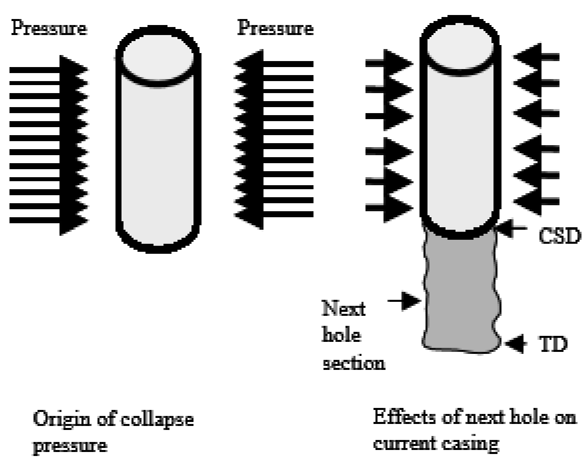

Figure 1. Collapse pressure

By using the above assumptions, we can take the internal pressure in the casing out of the equation and therefore:

$$\textbf{C (psi)} = 0.052 \times \rho \times \textbf{CSD} \qquad (2)$$

Where ρ is in (ppg) and CSD in (ft).

The above assumptions are specific for special cases only, e.g. when casing is run empty, complete loss of fluids to the formation. These are the only situations where we have 100% evacuation of the fluids inside the casing. None of these situations should be allowed to happen in field applications with the exception of encountering cavernous formations.

Other situations of fluid loss can be encountered in the bore hole and are discussed below.

When encountering a cavernous formation, loss of fluids will occur such that the mud column inside the casing will drop until the hydrostatic pressure of it balances that of the formation's fluids. If the pore pressure of the formation was not known, it will be assumed as 0.465 psi/ft, which is the hydrostatic pressure, sine pressurized formations are assumed to be connected to aquifers or the sea.

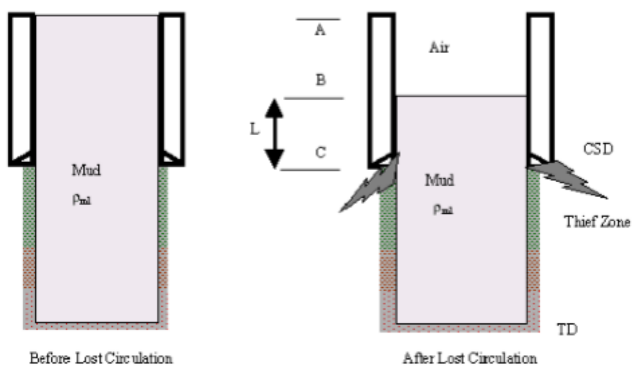

Figure 2. Mud Column High due to lost circulation

In this case, see figure 2, the high of the mud column calculated by the following procedure:

$$\textbf{Pressure at thief zone} = \textbf{CSD} \times 0.465 \qquad (3)$$

$$\textbf{Internal Pressure at shoe} = L \times \rho m \times 0.052 \qquad (4)$$

Equating equations (3) and (4) we get:

$$L = \frac{CSD \ x \ 0.465}{0.052 \ x \ \rho m} \qquad (5)$$

And thus the depth to the top of the mud column is

Depth to top of mud column = CSD – L (6)

Note: In the above calculations, the thief zone is assumed to be at CSD, whereas it could be anywhere from CSD to TD.

In this case, the depth to the top of the mud (h) inside the casing after loss is calculated by the following equation:

$$h = \left(\frac{\rho m - \rho f}{\rho m}\right) x \ Dz \qquad (7)$$

the high of the mud column is then calculate by the following equation:

$$L = (CSD - h) \qquad (8)$$

Where:

Pm = Mud density to drill next casing (ppg).

Pf = Formation pressure of thief zone (psi/ft) (assume = 0.465 psi/ft).

L = Length of mud column inside casing (ft).

CSD = Casing Setting Depth (TVD) (ft).

Dz = Depth to thief zone (ft).

Collapse pressure calculations for different casing strings are supported by different considerations. It is also supported by the knowledge f the formations from previously drilled wells. The following assumptions are applied:

Conductor casings are assumed to experience total loss of fluids; thus the internal pressure is zero.

Surface casing strings are assumed to have total loss by some companies, while others prefer to assume 40% fluid loss. These assumptions can lead to over design. A solution for this problem is to perform partial loss calculations.

Intermediate casing sections are never completely empty, since the mud column is too high, and thus partial loss calculations are applied.

Production casing is assumed to have total loss in the following cases:

- Plugged perforation and the well head pressure is bled to zero, and thus no fluids are present in the well to support the casing walls.
- Artificial lift operations, gas lift particularly, which decreases the density of the fluid column inside the casing.
- Underbalanced drilling, air/gas drilling.
- Blowouts which completely unloads the casing from fluids

If none of these situations is likely to occur, than it should be designed based on partial loss.

5.2.2- Burst Criterion:

Burst occurs when the burst strength of the casing is exceeded i.e the effective internal pressure (burst pressure) inside the casing is higher. Burst pressure is high at the surface and low at the casing shoe where internal pressure resists external pressure of the fluids.

Burst Pressure (psi) = Internal Pressure – External Pressure (9)

Burst pressures are straight forward for developing wells. However, they are complex for exploration wells due to the uncertainties in depths of formations, type of fluids, porosity, permeability, and temperature. Companies have developed manuals that detail separate designs for both exploration and development wells based on their previous experiences.

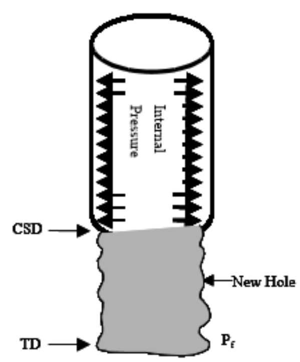

Figure 3. Burst Pressure inside the casing.

Burst Pressure occurs when formation fluids enter the wellbore while drilling or when producing next hole. Burst criterion one can design for 2 cases. The first is unlimited kick and the second is limited kick.

Unlimited kick: The design is based on an unlimited gas kick that fills the casing and removes the las drop of mud from the hole and the well is shut in. This case is unrealistic since small kicks in the order of 10bbls can be detected.

However, production from a gas reservoir represents the exact case, but the gas is flowing in a controlled manner instead. If the gas leaves the tubbing than the casing is subjected to the pressure of the gas and could burst if not designed properly.

Considering this design criterion, referring to figure 3, and assuming an unlimited kick of pressure Pf from TD, the internal pressure at the surface and at the casing shoe are given by:

$$\textbf{Internal pressure at surface (psi)} = P_f - (G \times TD) \qquad \textbf{(10)}$$

$$\textbf{Internal Pressure at shoe (psi)} = P_f - (G \times (TD - CSD)) \qquad \textbf{(11)}$$

Where G is the gas pressure gradient = 0.1 psi/ft.

Two points should be assumed when considering a gas kick:

- Casing seat should be selected so that the gas pressure at the casing shoe is less than the formation breakdown pressure at the shoe.
- The reservoir in the open hole to determine the gas pressure. It is determined via Logs in developing wells while in exploration wells it is assumed to be equal to the density of the mud which is expected to be used to drill the next section.

Limited Kick: This method is applied by assuming realistic kick size and then we calculate the pressure at the surface and at the casing shoe assuming that the kick is circulated out of the hole using the driller's method of well control. Whatever volume of a kick is used, a realistic value of formation pressure must be used as this is the variable that mostly affects the calculation.

External Pressure for Burst Design:

The external pressure (back-up load) is of the most ambiguous variables to be determined. It is largely determined by the type of casing, mud type, cement density, height of cement and formation pressure.

The value of this pressure should be calculated even though the casing is cemented since we cannot ensure that a continuous cement sheet is formed around the casing, no fluids present inside the casing, and surely we cannot eliminate the pores inside the cement that makes pressure communication with the formations possible.

Several methods of calculating the back-up load are provided by a number of oil companies. Of which are:

1- **External pressure (psi) = 0.465 x CSD** **(12)**
   This uses a column of salt water to provide the back-up pressure assuming that after some time all muds and cement will degrade to a density equal to that of salt water = 0.465 psi/ft.
   It is recommended by Rabiah to use this method for casings that are likely to be in the ground for 5 years.

2- For casing strings that are cemented to the top, Conductors and surface, the back-p pressure is assumed equal to the pore pressure of the formation since the casing will degrade and the casing will be exposed to the formation.

   Thus, **External Pressure = maximum expected pore pressure.**
   In this case the maximum pore pressure will be that of salt water = 0.465 psi/ft since the conductor and the surface casing will only be exposed to water bearing formations.

3- For un-cemented sections

   - In open holes use mud to balance the lowest pore pressure in the hole.
   - Inside another casing, use mud to TOC and from there use mud to balance the lowest pore pressure from TOC to TD.

5.3- Design Factor

Casing strings are never designed to their yield strength in tension, burst, or collapse. Instead a factor is used to design the casing strength to ensure that the casing is never loaded to failure. Thus, in casing design we use the Design factor instead of the factor of safety.

Design factor is used to design tubular and casing based on comparing the maximum service load with the API minimum yield strength. And since the tubulars will not fail at the minimum yield strength, the Design factor gives greater scope of safety when compared with the safety factor.

$$\textbf{Design Factor} = \frac{\textit{Rating of the pipe}}{\textit{Maximum expected service load}} \qquad \textbf{(13)}$$

Ex: DF-Burst = $\frac{\textit{Burst Strength}}{\textit{Burst Pressure}}$

This factor should always be greater than 1 in order to compensate for forces that are difficult to calculate such as the shock load.

*Some recommended Design factors (Rabia):

Collapse	1
Burst	1.1
Tension	1.6 - 1.8
Compression	1
Triaxial Design	1.1

Table 3. Design factor recommendations.

5.4- Casing Selection Procedure based on Burst and Collapse pressures

If the choice in selection of the casing is available, the following procedure is followed:

1- Plot a graph of pressure against depth, starting the depth and pressure scale at zero and mark the CSD on the graph. (as shown in figure 4)

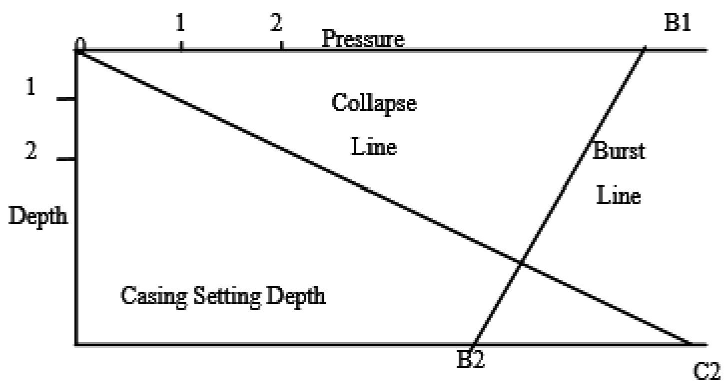

Figure 4. Collapse and Burst Lines.

2- Draw the collapse line; place point C1 at zero depth and point C2 at the CSD.(for partial loss, there will be 3 points, one at zero C1 and C2 at (CSD-L) and C3 at CSD)
3- Draw the Burst line; plot B1 at zero depth and point B2 at CSD. (For production casing, the highest pressure will be at the casing shoe)
4- Plot the collapse and burst strength of the available casing as shown in the figure5. (example N80 and K55 are shown on the graph)

The casing string should satisfy both the collapse and burst pressures. As shown in figure5.

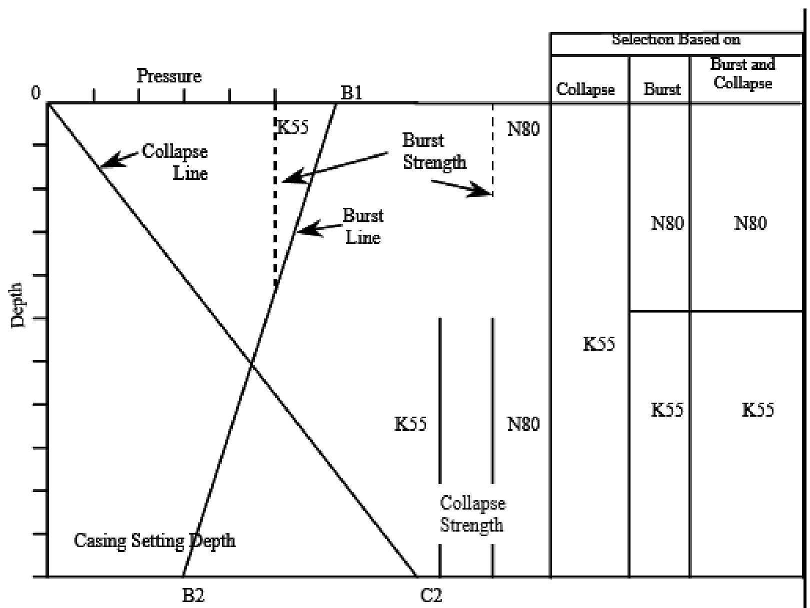

Figure 5. Selection based on Burst and Collapse.

5.5- Combination Strings

In casing strings the maximum tension occurs at the uppermost joint, in addition burst pressures are most severe at the top so to design should incorporate heavy casing joints at the upper section. Collapse pressure is maximum at the bottom joint and thus heavy casing strings are required at the bottom parts.

To compensate for this problem, combination string is used, which means that different casing grades of different are used for different sections.

Strong and heavy casing is used at the surface, light but yet strong casing is used in the middle section, and heavy casing may be required at the bottom to withstand the high collapsing pressure. (figure5.)

The combination string method represents the most economic and safest way. However, using combination string may create a problem for the drilling crew.

5.6- Tension Criterion

Most of the tensile stress arises from the weight of the casing itself**.** Other loads can also cause the casing string to be subjected to tension, of which: bending, drag, shock loading, and pressure testing.

The upper most joint of the casing string will be subjected to the highest tensile strength of the total string, and for that the selection of the casing grade is based on a design factor of 1.6 to 1.8 for the top joint.

The tensile forces are determined in the section below.

5.6.1- Weight of Casing in air using TVD (positive force)

Is calculated for each casing joint and summed up to find the total load that the casing generates from its own weight.

Casing air weight = casing weight (lb/ft) x hole TVD (ft) (14)

This force is the main tensile force and is present when the casing is static or in motion.

5.6.2- Buoyant Weight of Casing (negative force)

It is the difference between the casing air weight and the buoyancy force.

This force is present unless total loss of mud occurred in the hole.

The Buoyancy force is determined by:

- Open ended casing: **Buoyancy Force (lb) = Pe x (Ae – Ai) (15)**
- Closed ended casing: **Buoyancy Force (lb) = (Pe x Ae) – (Pi x Ai) (16)**

Where: Pe = External hydrostatic pressure / Pi = Internal hydrostatic pressure and Ae and Ai are the external and internal areas of the casing respectively. (check figure 6)

In most cases however, and because the mud inside and outside the casing are the same, equation (15) is used.

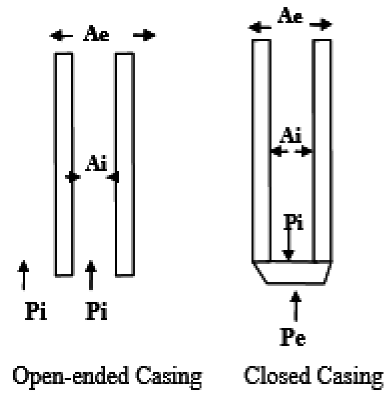

Figure 5. Buoyancy Force.

5.6.3- Bending Force (positive force)

This force is encountered in deviated wells and is present if the is static or in motion.

The bending force is given by:

Bending Force = 63 x Wn x OD x Ø (17)

Where: Wn: is the weight f the casing string (lb/ft) / Ø = dogleg severity (degrees/100ft).

5.6.4- Shock Load

This load occurs as a result of applying sudden deceleration of the casing, casing picked off the slips, slips are kicked in while the pipe is moving, or the casing hits a bridge or jumped off a bridge downhole. It only exists when the pipe is in motion and stops suddenly.

This force happens in a very short time (approximately 1 second). It depends on the velocity of the casing string. This velocity is difficult to measure and thus it is suggested by Rabiah. To use the following equation:

Shock Load (max) = 1500 x Wn (18)

5.6.5- Drag Force (positive force)

This force arises in deviated wells when pulling out of hole, pipe in motion. Determining this force is complex since it requires good knowledge of the friction factors between the casing and the formation and thus it is assumed to be equal to 100,000 lbf.

5.6.6- Pressure Testing (positive force)

The casing should be tested to the maximum pressure which it sees during drilling and production operations. Pressure testing lasts for 15 minutes.

$$\textbf{Pressure Test Force (lb)} = \frac{\pi(ID)^2}{4} \textbf{ x Test pressure} \qquad \textbf{(19)}$$

Where ID is the casing inner diameter (in).

After determining all these loads, the total surface tensile load (installation load) is calculated by summing these forces and compared to the minimum tensile strengths of the casing joint and pipe body (choose the lowest) with a design factor = 1.6 to 1.8. The tensile load must never exceed the derrick's load capacity.

The value of the total surface tensile load varies depending on the loading cases. There are 3 casing loading cases and they are described below.

1- Running Conditions: When the casing is run in hole and cement is not yet pumped.

   Total tensile force = weight of casing - buoyancy weight + shock load + bending force (20)

2- Static Conditions: When the casing is in the ground and cemented in place.

   Total tensile force = bending force - buoyant weight + miscellaneous forces (21)

   Miscellaneous forces such as the forces of production, injection, temperature etc.

3- Pressure testing Conditions: When the casing is set, the mud is pumped and the mud is used to apply pressure on the top plug.
   The best time to test the casing is when the cement is still wet, in order not to induce any fractures in the cement.

   Total Tensile Force = pressure testing force - Buoyancy weight + bending force (22)

When the total tensile forces are calculated for the casing string at the different loading cases, a table is drawn and all the calculated values are presented and the casing is selected based on the given values with considerations on the Design Factor.

	Running Conditions	Pressure Testing Conditions	Static Conditions
Buoyant Weight	315,423	315,423	315,423
Shock Load	199,500	0	0
Bending Force	125,685	125,685	125,685
Pressure testing Force	0	687,349	0
Total Force (lbf)	530,608	1,128,457	441,108

Table 3. Total Surface tension Calculation.

6. Conclusion and Closing Remarks

The casing design is a tough time consuming task that requires the integration of information from several disciples. It is an indispensable process towards designing the well in a cost effective and safe way.

Furthermore, companies are not always able to purchase specific casing strings with small quantities for their wells instead companies tend to use what they have in their stocks. Off Corse getting the proper casing that is specified by the well's casing design program but saving a little money has a higher priority for some firms. After all, they are all drilling for the money.

References:

1- Rabia H (1987) "Fundamentals of Casing Design". Kluwer Group.
2- Rabia H "Well Engineering and Construction". Chapter 5 Casing Desgin Principles.