

Planning and Design of Casing

**A FINAL PROJECT REPORT
SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR
THE DEGREE OF BACHELOR OF TECHNOLOGY
(APPLIED PETROLEUM ENGINEERING)**



**Submitted To
UNIVERSITY OF PETROLEUM AND ENERGY STUDIES**

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CERTIFICATE

This is to certify that the Project Report on “**Planning and Design of Casing**” submitted to University of Petroleum & Energy Studies, Dehradun by **Viraj Nangia** in partial fulfillment of the requirement for the award of Degree of **Bachelor of Technology in Applied Petroleum Engineering** (Academic Session 2003-2007) is a bonafide work carried out by him under my supervision and guidance.

This work is deemed good and satisfactory.

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Contents

Abstract

1. Fundamental Aspects Of casing Design

1.1	Introduction.....	6
1.2	Function Of Casing.....	6
1.3	Types Of Casing.....	6
1.4	Types of Liner.....	11
2.1	Fracture gradient.....	12
2.2	Overburden Stress.....	12
2.3	Formation Pore Pressure.....	13
2.4	Rock Strength.....	14
2.5	The Principal Stresses.....	15
2.6	Formation Break Down Pressure.....	15
2.7	Procedure for Casing Seat Selection.....	16
2.8	Strength Properties of casing.....	17
2.9	Factors Influencing Casing Design.....	22
3.0	Principals of casing design.....	29
3.1	Setting Depth.....	29
3.1.1	Casing for Intermediate Selection of the well.....	31
3.1.2	Surface Casing String.....	34
3.1.3	Conductor pipe.....	36
3.2	Casing String Sizes.....	37
3.2.1	Production Casing String.....	37

3.2.2 Number of Casing Strings.....	37
3.2.3 Drilling Conditions.....	37
3.3 Selection of Casing Weight, Grade and Couplings.....	40
3.3.1 Surface Casing (16-in).....	42
3.3.2 Intermediate Casing (13 3/8-in. pipe).....	52
3.3.3 Drilling Liner (9 5/8-in. pipe).....	63
3.3.4 Production Casing (7-in. pipe).....	67
3.3.5 Conductor Pipe (26-in. pipe)	74
3.4 Final selection	76
4.0 Well head Selection.....	77

References

Appendix

Abstract

Casing design has followed an evolutionary trend and most improvements have been made to the advancements of technology. Contributions to the technology in casing design have come from fundamental research and field tests, which made casing safe and economical.

It is the purpose of this report to gather much of the information available in the literature and show how it may be used in deciding the best procedure for casing design, i.e., optimizing casing design for deriving maximum profit from a particular well.

1.1 INTRODUCTION

Casing is an essential part of drilling and completion of an oil and gas well. There are two different jobs that a casing must be designed for. The first is to allow you to safely drill the well and resist any forces or conditions that are imposed on it during drilling, without sustaining significant damage. The second is to act through the life of the well to meet the well objectives without requiring a work over. The design criteria for each string of casing are different during drilling and during the remainder of the life of the well. Computer programs make detailed casing designs routinely possible, including tri-axial analysis.

1.2 FUNCTIONS OF CASING

To keep the hole open and to provide a support for weak, or fractured formations. In the later case, if the hole is left un-cased, the formation may cave- in and re -drilling of the hole will then become necessary.

- To isolate porous media with different fluid / pressure regimes from contaminating the pay zone. This is actually achieved through the combined presence of cement and casing. Therefore, production from a specified can be made.
- To prevent contamination of near- surface fresh – water zones.
- To provide a passage for hydro-carbon fluid, most production operations are carried out through special tubing which are run inside the casing.
- To provide a stable connection for the well-head equipment (e.g.; X-mass tree). The casing is also served to connect the blowout prevention equipment (BOP), which is used to control the well while drilling.
- To provide a hole of known diameter and depth to facilitate the running of testing and completion equipments.

1.3 TYPE OF CASINGS

In actual practice it would be much cheaper to drill a single size hole to total depth (TD), probably with a small diameter drill bit and then case the hole from the surface to the TD. However, the presence of high pressurized zones at different depths

along the well bore, and the presence of weak, unconsolidated formations or sloughing shaly zones necessitates running casing to seal off these troublesome zones and to allow of drilling to TD. Different sizes of casing are therefore run to case off the various sections of hole, a large size of casing run at the surface followed by one or several intermediate casings and finally a small size casing for production purpose. Many different size combinations are run in different parts of the world. The types of casing currently used are as follows:

1.3.1 STOVE CASING

These are the marine conductor or foundation pile for offshore drilling and is run to prevent washout of near surface unconsolidated formations, to provide a circulation system for the drilling mud and to ensure the stability of the ground surface upon which the rig is sited. This pipe does not carry any well head equipment and can be driven into the ground with a pile driver. The normal size for a Stove pipe ranges from 26 in (660.4 mm) to 42 in (1066.8 mm).

1.3.2 CONDUCTOR CASING

The first casing is usually called the conductor casing. It may be driven into the ground with a pile driver or it may be cemented inside a drilled hole. The shoe depth selected for the conductor casing should be strong enough to withstand fracturing during drilling the next hole interval which is assumed to have no hydrocarbon bearing intervals. The purposes of this casing are to –

- Conduct drilling fluid returns back up to the rig during surface hole drilling so that a closed circulation system can be established.
- Protect unconsolidated surface formations from being eroded away by the drilling fluid.
- Some times support the weight of the well head and BOPs.

Conductor pipe is always cemented to the surface. Typical size for a conductor casing is 18^{5/8} in (473 mm) to 20 in (508 mm) in Middle East and 30 in (762 mm) in North Sea exploration.

1.3.3 SURFACE CASING

The surface casing is the first casing that is set deep enough for the formations at shoe to withstand pressure from a kicking formation further down. Surface casing is treated as conductor casing if no hydrocarbon are expected in the next hole interval or alternatively as intermediate casing in the event that hydrocarbons are expected in the next phase of drilling. Surface casing is run to prevent caving of weak formations that are encountered at shallow depths. This casing should be set in competent rocks such as hard lime stones. This will ensure that the formation at the casing shoe will not fracture at high hydrostatic pressure which may be used later. The purposes of the surface casing are to—

- Allow a BOP to be nipped up so that the well can be drilled deeper.
- Protect fresh water sources close to the surface from pollution by the drilling fluid.
- Isolate unconsolidated formations that might fall into the well- bore and cause problem.
- Support the weight of all casing string run below the surface pipe.

A typical size of this casing is 13^{3/8} in (340 mm) in the Middle East and 18^{5/8} in (473 mm) or 20 in (508 mm) in North Sea operations.

1.3.4 INTERMEDIATE CASING

Depending upon the depth of the well and the anticipated problem in drilling the well, such as abnormal pressure formations, heaving formations or lost circulation zones, it may be necessary to set a number of intermediate strings of casing to seal off the long open hole or zones causing trouble. A shallow well may not need an intermediate casing; a deep well may need several. The intermediate casing serves as strong posts between the surface casing and the production casing. Good cementation of this casing must be ensured to prevent communication behind the casing between the lower hydrocarbon zones and upper water formations. Multistage cementing may be used to cement long strings of intermediate casing. The primary purpose of the intermediate casing are to –

- Increase the pressure integrity of the well so that it can be safely deepened.
- Protect any directional work done e.g. kicking off a directional well is often done under surface casing and is then protected by the first intermediate casing.

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- Consolidate progress already made.

The most common size of this casing is $9\frac{5}{8}$ in (244.5 mm).

1.3.5 PRODUCTION CASING

The production casing is often called oil string. It houses the completion tubing, through which hydrocarbons will flow from the reservoir. If the completion tubing were to leak, the production casing must be able to withstand the pressure. Sometimes the production casing is cemented in place with the casing shoe above the reservoir and another hole section drilled. This may be protected with a liner rather than a string of casing. It is run to isolate producing zones, to provide reservoir fluid control, and to permit selective production in multizone production. This is the string through which the well will be completed. The purpose of this casing is to –

- Isolate the producing zones from the other formations.
- Provide a work shaft of a known diameter to the pay zone.
- Protect the production tubing and other equipments.

The normal size for the production casing is 7 in (177.8 mm)

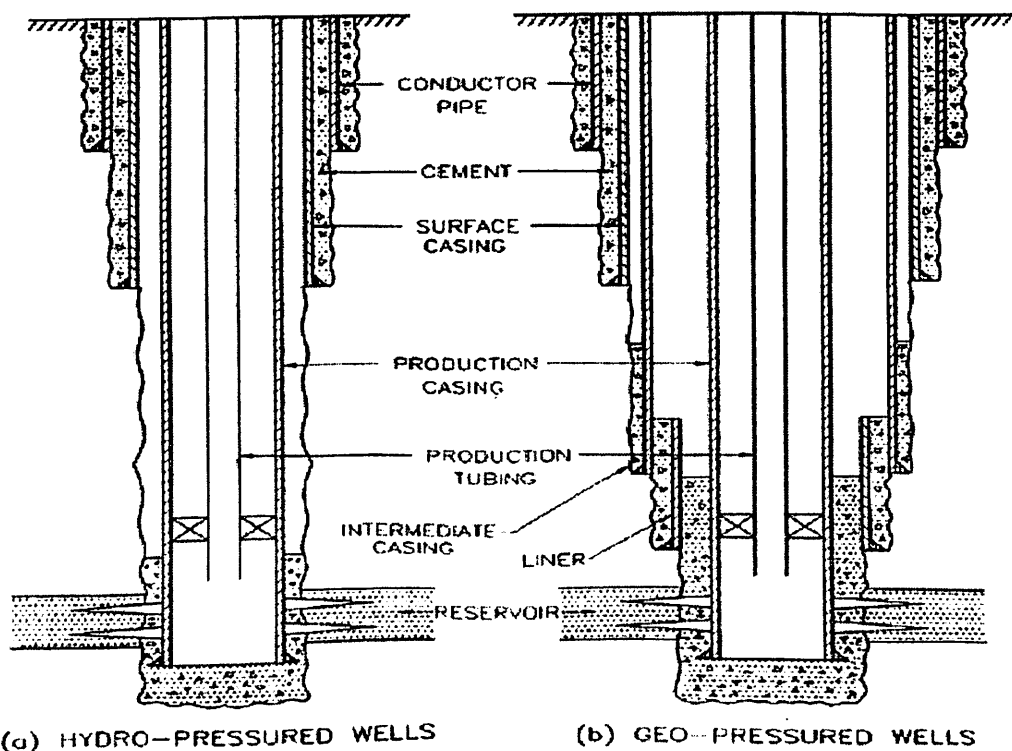


Fig. 1.1: Typical casing program showing different casing sizes and their setting depths.

1.3.6 LINER CASING

A liner is a string of casing that does not reach the surface. Liners are hung on the intermediate casing by use of a suitable arrangement of a packer and slips called a liner hanger. In liner completion both the liner and the intermediate casing act as the production string. Because a liner is set at the bottom and hung from the intermediate casing, the major design criterion for a liner is the ability to withstand the maximum collapse pressure. There are pros and cons to liners.

ADVANTAGES:

- **Economics:** The cost of the liner and associated equipment is less than the cost of a full string of casing to the surface. Also running and cementing time reduced.
- **Utility:** The inside diameter of the liner is inevitably less than the ID of the production casing. This allows tools to be run as part of the completion that would be too large to fit inside the liner but could be set higher up, inside the casing.
- Small size allows completion with adequate size of production tubings.

DISADVANTAGES:

- **Complexity:** The equipment required to run a liner is much more complex than for a casing so there is more chance that something will go wrong.
- Possible leak across a liner hanger.
- Difficulty in obtaining a good primary cementation due to the narrow annulus between the liner and the hole.

1.4 TYPE OF LINERS

Drilling Liners are used to isolate lost circulation or abnormally pressurized zones to permit deeper drilling.

Production Liners are run instead of a full casing to provide isolation across the producing or injection zones.

The Tie-back Liners is a section of casing extending upwards from the top of an existing liner to the surface or well head.

The **Scab Liner** is a section of casing that does not reach the surface. It is used to repair existing damaged casing. It is normally sealed with packers at top and bottom and in some cases is also cemented.

The **Scab Tie-back Liner** is a section of casing extending from the top of an existing liner but does not reach the surface. The scab Tie-back liner is usually cemented in place.

2.1 FRACTURE GRADIENT

In oil and gas well drilling the fracture gradient may be defined as the minimum total in situ stress divided by the depth. Knowledge of fracture gradient is essential to the selection of proper casing seats, for the prevention of lost circulation and to the planning of hydraulic fracturing for the purpose of increasing of well productivity in zones of low permeability. Accurate knowledge of the fracture gradient is of paramount importance in areas where selective production and injection is practiced. In such areas the adjacent reservoirs consist of several sequences of dense and porous zones such that, if a fracture is initiated (during drilling or stimulation), it can propagate, establishing communication between H/C reservoirs and can extend down to a water bearing zone.

The fracture gradient is dependent upon several factors, including type of rocks, degree of anisotropy, formation pore pressure, magnitude of overburden and degree of tectonics within the area. It follows that any analytical prediction method will have to incorporate all of the above factors in order to yield realistic values of the fracture gradient.

Various methods currently used in oil industry to determine or predict fracture gradient of rock with some important definitions are as follows:

2.2 OVERBURDEN STRESS

Over burden stress σ_v is defined as the stress arising from the weight of rock over laying the zone under consideration. In geologically relaxed areas having little tectonic activity, the overburden gradient is taken as 1 psi / ft (0.2262 bar / m). In tectonically active areas as in sedimentary basins which are still undergoing some compactions or in highly faulted areas, the overburden gradient varies with depth, and

Planning & Design of Casing

average value of 0.8 psi / ft is normally taken as being representative of the overburden gradient. in general the over burden gradient varies from field to field and increases with depth , owing to rock compaction .For a given field , accurate value of overburden gradient can be obtained by averaging density logs from several wells drilled in the area .

A Graph of bulk density against depth is then plotted as shown in fig 2.1 (a).The density – depth graph can be converted to an overburden gradient – depth graph fig 2.1 (b) by the use of the relation.

$$\text{Overburden stress} = (\text{bulk density}) \times (\text{depth}) \times (\text{acceleration due to gravity})$$

In porous formations the overburden stress, σ_v , is supported jointly by the rock matrix stress, σ_s , and the formation pore pressure P_f . Thus ,

$$\sigma_v = \sigma_s + P_f$$

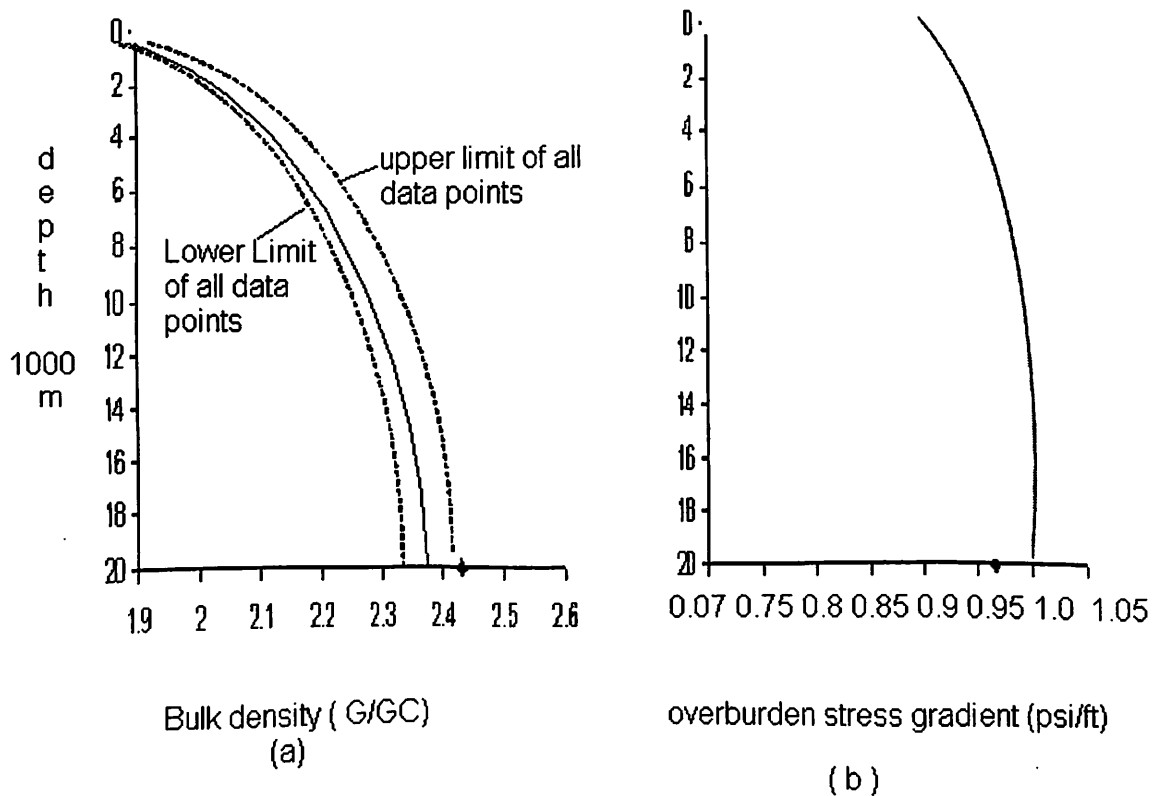


Figure 2.1 (a) composite bulk density curve from density log data for the Gulf coast, (b) composite overburden stress gradient for all normally compacted Gulf coast sediments. (After EATON 1965)

2.3 FORMATION PORE PRESSURE

Formation pore pressure is defined as the pressure exerted by the formation fluid on the walls of the rock pores. The pore pressure supports part of the weight of the overburden, while the other part is supported by the grains of the rock. The terms pore pressure, formation pressure and the fluid pressure are synonymous, referring to formation pore pressure.

Formations are classified according to the magnitude of the pore pressure gradient. Two types of formation pressures are recognized generally.

2.3.1 NORMAL PORE PRESSURE OR HYDRO- PRESSURE

A Formation is said to be normally pressurized when its pore pressure is equal to the hydrostatic pressure of a full column of formation water. Normal pore pressure is usually of the order of 0.465 psi / ft (0.105 bar/m).

2.3.2 ABNORMAL FORMATION PRESSURE OR GEO PRESSURE

This type exists in zones which are not in direct communication with its adjacent strata. The boundaries of the abnormally pressured zones are impermeable, preventing fluid communication and making the trapped fluid support a large proportion of the overburden stress. The maximum value of the abnormal formation pressure is 1 psi / ft for tectonically relaxed areas and 0.8 psia / ft for active areas. Exceptions to these values were found in certain parts of Iran and Russia in which the abnormal formation pressure is in excess of the overburden gradient.

NORMAL AND ABNORMAL FORMATION PRESSURES can be detected by geophysical and logging methods. GEOPHYSICAL methods provides prediction of formation pressure before the well is drilled, while logging methods provide information after the well or section of well has been drilled. Logging tools are run on a wire line in

side the well .They include electronic , sonic, electrical , neutron , bulk density and lithology logs .

2.4 ROCK STRENGTH

Rock strength can be specified in terms of tensile strength , compressive strength , shear strength or impact strength .In the context of fracture gradient only the tensile strength of rock is of importance .The tensile strength of the rock is defined as the pulling force required to rupture a rock sample divided by the samples cross-sectional area. The tensile strength of rock is very small and is of the order of 0.1 times of the compressive strength. Thus a rock is more likely to fail in tension than in compression.

2.5 THE PRINCIPAL STRESSES

At any point below the earth surface three mutually perpendicular stresses exist. The maximum principal stress σ_1 , is normally vertical and is equal to the over-burden stress in the vertical holes. The value of the over-burden stress is 1 psi / ft. The intermediate and minimum total principal stress (σ_1, σ_2) are horizontal, and directly influence the fracturing of the rock. Theoretically the fluid pressure required to rupture a bore – hole should be greater than or equal to the minimum principal stress. However, the creation of a bore hole within the earths surface produces a magnification of stresses around the bore – hole walls such that the resulting stresses are several times larger than the least principal stress.

2.6 FORMATION BREAK-DOWN PRESSURE

The formation break-down pressure is the pressure required to over come the well bore stresses in order to fracture the formation in the immediate vicinity of the well-bore

2.7 PROCEDURE FOR CASING SEAT SELECTION

Accurate knowledge of pore pressure and fracture gradient plays a major role in the selection of proper casing seats which would allow the drilling of next hole without fracturing. Pore pressure, mud weight, fracture gradient are used collectively to select proper casing seats.

The mechanism for selecting casing setting depth is as follows:

- The well objective is clearly defined.
- Actual problems encountered in nearby wells are listed.
- The potential problems encountered in nearby wells are short listed.
- Pore, mud and fracture pressure profile for the well is estimated.
- The pore, mud and fracture pressure profile is overlaid against the lithological column, potential troublesome zones and the hydrocarbon bearing zones.
- A basic casing program is prepared as per the procedure detailed out in solving the real problem.
- Production casing shoe depth requirements are studied and suitable formation and depth are selected so as to meet these requirements as an absolute minimum.
- Intermediate casing shoe requirements are studied to satisfy designed kick tolerance and the differential pressure consideration and a suitable casing point is selected to meet these requirements as an absolute minimum.
- Kick tolerance and the maximum differential pressure are recalculated for the selected seat.
- Surface casing and conductor casing shoe depth requirements are studied and accordingly suitable formation and depth are selected.

Using the data of actual well we will illustrate the actual procedure for the casing seat selection.

2.8 STRENGTH PROPERTIES OF CASING

Casing pipe strength properties are generally specified as-

1. Yield Strength for (a) pipe body and (b) coupling,
2. Collapse Strength for pipe body,
3. Burst Strength for (a) pipe body, (b) coupling and (c) leak resistance of the connections.

2.8.1 YIELD STRENGTH

API Yield strength is defined as the tensile stress required to produce a total elongation of 0.65, 0.60 and 0.50 % of length for Q-125, P-110 and remaining grades respectively. It is customary to quote yield strength of casing while referring to the strength of casing.

The most common type of casing joints are threaded on both ends and fitted with a threaded coupling at one end only. The coupling is the box end of the casing joint. The strength of the coupling may be higher or lower than the yield strength of the main body of the casing joint. Hence, manufacturers supply data on both, body and coupling strength and the minimum of two to be used in casing design calculations. There are also available integral casing (i.e. with out couplings) in which the threads are cut in the pipe ends. For details of the equations required to calculate joint strength, refer to API bulletin 5C3.

Following is a brief summary of some currently available common API grades and their characteristics. Further reference should be made to the literature and to manufacturer's data to obtain specific and up to date information.

Properties of some common grades of steel used for casing:

API H40 Carbon steel: Strength characteristics given by normalizing (heat to 1650°F and air cooling). Suitable for H₂S service at all temperatures for tubings up to 80,000 lbs minimum yield strength or for all tubings above 175°F

API J55 Carbon steel: Strength characteristics given by normalizing (heat to 1650°F and air cooling). Suitable for H₂S service at all temperatures.

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API K55 Carbon steel: Strength characteristics given by normalizing (heat to 1650°F and air cooling). Suitable for H₂S service at all temperatures. J and K have the same minimum yield strength (55,000 psi) but J has an ultimate tensile strength (UTS) of 75,000 psi and K has a UTS of 95,000 psi. The UTS is what dictates the connection strength and so API gives higher tension values for K55 pipe. Note that for most other steel grades, the ratio of minimum yield to UTS is 136 but for K55 it is 1,727.

API L80 Carbon steel: Suitable for H₂S service at all temperatures.

API LHO 13Cr Alloy steel with 13% chromium: Suitable for CO₂ service. Susceptible to handling damage, galling, and work hardening.

API N80 Carbon Steel: Quenched and tempered to produce a fully martensite crystal structure-, gives higher strength, reduced carbon, and minimizes austenite structure to reduce susceptibility to sulfide stress corrosion cracking. Suitable for H₂S service at temperature over 150 °F. L and N have the same minimum yield strength (80,000 psi) but L has an ultimate tensile strength of 95,000 psi and N has a UTS of 110,000 psi. The UTS is what dictates the connection strength and so API gives higher tension values for N80 pipe.

API C75/QU/Q5 Carbon steel: Quenched and tempered to produce a fully martensitic crystal structure; gives higher strength, reduced carbon, and minimizes austenite structure to reduce susceptibility to sulfide stress corrosion cracking. C75 can be used for H₂S service at temperatures, C95 at temperatures over 150 °F.

API P105/110 high strength steel: Suitable for service only above 75°F.

API V150 High strength steel: Minimum yield Stress 150,000 psi not suitable for H₂S service.

2.8.2 COLLAPSE STRENGTH

Collapse strength is defined as the maximum external pressure required to collapse a specimen of casing. The procedure for determining the collapse strength is defined in API bulletin 5C3. Under the action of external pressure and axial tension a casing cross-section can fail in three possible modes of collapse – *elastic collapse*, *plastic collapse* and *failure caused by exceeding the ultimate tensile strength (UTS) of the material*. In elastic collapse the specimen fails before it deforms while in plastic collapse a certain deformation takes place prior to failure of the specimen. The transition between the three failure modes is governed by the tube geometry and material properties. These three modes of collapse under external pressure are governed by D/t ratio. It has been observed for thin tubes (large D/t ratio) collapse failure mode is expected to be elastic. As the D/t ratio decreases or as the pipe become thicker the collapse failure mode changes to plastic (for intermediate D/t ratios) or to ultimate strength (for low values of D/t).

2.8.3 ELASTIC COLLAPSE

The elastic collapse pressure P_c can be determined by the following formula:

$$P_c = \frac{2E}{(1-\nu^2)} \times \frac{1}{\left[\frac{D}{t} \times \left\{ \frac{D}{t} - 1 \right\}^2 \right]}$$

Where,

E = Young Modulus of steel,

ν = Poisson's ratio;

t = casing thickness; and

D= outside diameter of the casing.

In Empirical units $E = 30 \times 10^6$ psi and $\nu = 0.3$;

Hence, equation becomes

$$P_c = \left[\frac{46.95 \times 10^6}{\frac{D}{t} \left(\frac{D}{t} - 1 \right)^2} \right]$$

In metric units

$$P_c = \left[\frac{2.198 \times 10^6}{\frac{D}{t} \left(\frac{D}{t} - 1 \right)^2} \right] \text{ bar}$$

The above equations are applicable to range of D/ t values given in the *Appendix-A*.

2.8.4 PLASTIC COLLAPSE

The minimum collapse pressure (P_p) in the plastic range may be calculated from the following equations:

$$P_p = Y \left(\frac{A}{D/t} - B \right) - C$$

Where,

A, B and C are constants depending on the grade of steel used and Y is the yield strength.

Equation is applicable for the range of D/t values given in the tables .The ratio D/ t should first be determined , and if it falls in the range given in the *Appendix-A*, then the equation is applicable and the values of A,B,C are used directly from the table

2.8.5 TRANSITION COLLAPSE PRESSURE

The collapse behavior, P_T , of steel in the transition zone between elastic and plastic failure is described by the following formula

$$P_T = Y \left(\frac{F}{D/t} - G \right)$$

Where F and G are constants, given by

$$F = \frac{46.95 \times 10^6 \left(\frac{3B/A}{2 + B/A} \right)^3}{Y \left[\frac{3B/A}{2 + (B/A)} - (B/A) \right] \left[1 - \frac{3B/A}{2 + (B/A)} \right]^2}$$

$$G = \frac{FB}{A}$$

The range of D / t values applicable to equation is given in the table together with F and G Values

2.8.6 BURST OR INTERNAL YIELD STRENGTH

Burst strength is defined as the maximum value of internal pressure required to cause the steel to yield. The minimum burst pressure for the casing is calculated by the use of Barlow's formula

$$P = 0.875 \left(\frac{2Y \times t}{D} \right)$$

Where,

t = thickness of the casing (inch);

D = Outer Diameter of casing (inch), &

Y = minimum yield strength (psi)

The above equation gives the burst resistance for minimum yield of 87.5% of the pipe wall, allowing for a 12.5% variation of wall thickness due to manufacturing defects. Burst failure occurs by either rupturing of pipe body failure of coupling or leakage of coupling threads. Hence API has defined three internal pressure resistance values for casing and the minimum one should be used for calculation. In addition to pipe body Burst resistance, the other two resistances are:

- a) Internal yield pressure for coupling.
- b) Internal pressure leak resistance of connection

2.9 FACTORS INFLUENCING CASING DESIGN

Casing design is influenced by:

- a) Loading conditions during drilling and productions
- b) Formation strength at casing shoe.
- c) The degree of deterioration to which the pipe will be subjected during entire life of a well.

3.0 DESIGN CRITERIA

Following are the criteria which must be considered when carrying out detailed casing design.

- AXIAL LOAD
 - a) Axial tension
 - b) Axial compression
- COLLAPSE PRESSURE
- BURST PRESSURE
- OTHER LOADING CONDITIONS , IF ANY

AXIAL LOADS

a) AXIAL TENSION:

Most axial tension arises from the weight of casing itself. Other tension loadings can arise due to bending, drag, shock loading and pressure testing of casing. Since a number of parameters contribute to tensile loading, the tensile load on the casing should be calculated at the following stages

1. when running the pipe
2. when cementing
3. when pressure testing { drilling phase }

Four cases should be considered and a safety factor evaluated for each one of them

CASE: 1 **common force + shock loading** when running

CASE: 2 **common force + an over -pull** when running

CASE: 3 **common forces + a weight of cement force** when cementing

CASE 4: common force + a **pressure test** in the drilling phase

COMMON FORCE

Common force is the combination of the weight of the casing string less the buoyancy force in the minimum mud weight envisaged + the bending force .

- (i) Weight of casing (W)

$$W = W_n \times L \quad (\text{Kg} - \text{f})$$

Where,

W_n = casing nominal weight (Kg / m)

L = casing length in meters

- (ii) Buoyancy force BF is upward force acting on the bottom of the casing strength. True vertical depths must be used in a directional well. Any composite strings with different internal diameters must be considered separately.

$$BF = MW \times CSA \times L / 10 \quad (\text{Kg f})$$

Where,

MW = mud weight in g /cc

CSA = cross-sectional area cm^2

L = casing length in (m.)

- (iii) Bending force ($B_e F$): is a force acting in tension on the out side of the pipe and compressive force on the inside. It will be caused by any deviation in the well, resulting from side – tracks, build-ups and drop-offs or from sagging of casing caused by lack of centralization or wash-outs.

Bending calculations must be redone if a well has to be side tracked around a fish

$$B_e F = 29 \times RC \times D \times W_n \quad (\text{Kg} - \text{f})$$

Where,

RC = radius of curvature in degree / 30 m

D = out side diameter of pipe in (inch)

W_n = casing nominal weight in ppf

SHOCK LOADING

Shock loading is exerted on the casing string because of

- Sudden deceleration force, e.g. . if the spider accidentally closes or the slips are 'kicked in' on moving pipe or the pipe hits a bridge / ledge
- Sudden acceleration force, such as picking the pipe out of the slips or if the casing momentarily hangs –up on a ledge then slips off it.

Any of the above will cause a stress wave to be created which travels through the casing at the speed of sound .

Magnitude of shock load can be calculated as follows

$$\text{Shock loading} = 1.55 \times 10^3 \times V \times W_n \text{ (kg f)}$$

Where, V = peak velocity while running in m / sec

W_n = casing nominal weight in ppf

OVERPULL

Over pull contingency of 1,00,000 lbs (45.45 T) is normally incorporated. This is not exactly a design factor but a function of the hole conditions.

CEMENT FORCE (CF)

Cement force, a worst case situation is assumed as: the mud weight in the annulus is the lowest envisaged for the selection; the inside of the casing is full of cement slurry, with mud above; the shoe instantaneously plugs off just as the cement reaches it and the pressure rises to a value of say 100 kg/cm² before the pumps are shut down. It is appreciated that the cement will be 'running away' at this point with no positive displacement pressure being exerted.

$$CF = \left[\left\{ (CW - MW) \times \frac{L}{10} \right\} + 100 \right] \times A \text{ (kg f)}$$

Where,

CW = cement weight in gm/cc

MW = mud weight in gm/cc

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L = length over which CW & MW act in meter.

A = internal area of the casing in cm^2

PRESSURE TESTING

Pressure testing will be performed on the casing as the plugs are bumped and later on in the well depending on operational conditions. The actual test pressure will depend on:

- The rated burst strength of the casing.
- The well head pressure rating.
- The BOP stacks pressure rating.
- The maximum anticipated surface pressure.

(b) AXIAL COMPRESSION

Compressional effects occur in casing due to temperature effects in landed casing and because of the weight of other inner casing strings which are supported by the outer strings. Accordingly, as the compression loads are concerned, well falls one of three categories, as:

- Land well and sub sea wells
- Platform wells with surface wellheads
- Mud line suspension wells.

In land wells, if the outer casing is cemented all the way to surface it will be able to support all the expected compressional loads. If however, it is not cemented to surface, then there is a danger of buckling due to the compressive loads.

In Platform wells, with surface wellheads, there is a free standing part of the casing equivalent to the water depth plus air gap plus height to the wellhead deck. Buckling can occur on this free standing section. To prevent buckling, the outermost casing must be well centralized within the conductor and designed to be strong enough to withstand the likely buckling forces.

With mud line suspension wells, used mostly on jack-up wells, the weight of the casing is hung off at the sea bed. The tieback string which link the seabed wellhead with the surface equipment on the jack-up rigs is however, subject to buckling.

During drilling operations, in most of the cases, the temperature effect is so slight that it can be ignored. However, during the production phase, the compressive loads on the production string must be considered.

COLLAPSE PRESSURE

Collapse pressure originates from the mud column behind the casing. Since mud hydrostatic pressure increases with depth, collapse pressure will be maximum at bottom and zero at top. When a casing is subjected to a collapse pressure due to mud hydrostatic pressure from outside, it is called collapse load. The internal pressure (due to any reason) is called back-up. The difference between the collapse and internal pressure is termed as resultant. Resultant is the net pressure which is actually acting on the casing.

If the casing is design in collapse as total empty from inside it is known as **dry design**. In this case back-up equals to zero. Normally a surface casing is designed dry and intermediate casing is designed partially empty assuming that the casing shoe will be able to withstand minimum of native fluid column.

BURST PRESSURE

The Burst criterion in casing design is normally based on the maximum internal pressure resulting from a kick during drilling of the next hole section. For added safety in some cases, it is also assumed that influx fluid will displaced the entire mud, thereby subjecting the inside of the casing to the bursting effect of formation pressure. The load , back-up and resultant concepts is also applied here with a difference that the load in burst will be internal pressure , back -up will be external pressure.

OTHER LOADINGS

Other loadings that may developed in the casing includes

- Bending with tong during make-up

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- Pullout off the joint and slip crushing
- Corrosion and fatigue failure
- Pipe wear due to running wire line tools and drill string assembly in deviated and dog leg holes.
- Additional loadings arising from treatment operations like acidising , hydro fracturing, cement squeezing etc.

Additional loadings can not be determine directly and , it is assumed that they are taken care by the safety factor.

SAFETY FACTORS

Casing design is not an exact technique because of uncertainties in determining actual loadings and also because of change in casing properties with time resulting from corrosion and wear. A design factor is used to allow for such uncertainties and to ensure that the rated performance of the casing is always greater than the expected resultant loading.

In other words, casing strength is down rated by chosen safety factor. Every organization has its own policy of safety factors. Most commonly used design factors for casing design are:

Collapse - 1.00 to 1.125

Burst - 1.00 to 1.10

Tension - 1.60 to 1.80

Safety factors can be defined as the ratio between rated capacity of casing and the actual load.

$$SF_{\text{collapse}} = \frac{\text{rated collapse resistance of casing}}{\text{actual resultant collapse Pressure.}}$$

$$SF_{\text{burst}} = \frac{\text{rated burst rating of casing}}{\text{actual resultant burst pressure}}$$

$$SF_{\text{Tension}} = \frac{\text{rated Yield strength (Pipe body or joint which ever is minimum)}}{\text{Actual resultant tensile load.}}$$

BI AXIAL EFFECTS

Burst and collapse resistances of casing are altered when the pipe is under tension or compression load. These changes may, but do not necessarily apply to connectors. Coupling manufactures should be consulted in stringent operating conditions. The quality changes in pipe resistance are as follows:

TYPE OF LOAD	RESULT
Tension	Collapse – decreases Burst – increases
Compression	Collapse – increases Burst – decreases

An easy and faster way to finding the quantitative effect of axial tension on collapse resistance is by referring to the collapse curve factors.

To determine the collapse strength under a given tensile load, divide the tensile load by the pipe body yield strength, to obtain load factor (X). Read collapse rating factor (Y) against load factor (X) from the table (Appendix-B). Multiply rated collapse strength with collapse rating factor (Y) to find reduced collapse strength under the tensile load

PRINCIPLES OF CASING DESIGN

The design of a casing program involves the selection of setting depths, casing sizes and grades of steel that will allow for the safe drilling and completion of a well to the desired producing configuration. Very often the selection of these design parameters is controlled by a number of factors, such as geological conditions, hole problems, number and sizes of production tubing, types of artificial lift equipment that may eventually be placed in the well, company policy, and in many cases, government regulations.

Of the many approaches to casing design that have been developed over the years, most are based on the concept of maximum load. In this method, a casing string is designed to withstand the parting of casing, burst, collapse, corrosion and other problems associated with the drilling conditions. To obtain the most economical design, casing strings often consist of multiple sections of different steel grades, wall thicknesses, and coupling types. Such a casing string is called combination string. Cost savings can sometimes be achieved with the use of liner tie—back combination strings instead of full strings running from the surface to the bottom.

3.1 SETTING DEPTH

Selection of the number of casing strings and their respective setting depths is based on geological conditions and the protection of fresh-water aquifers. For example, in some areas, a casing seat is selected to cover severe lost circulation zones whereas in others, it may be determined by differential pipe sticking problem or perhaps a decrease in formation pore pressure. In deep wells, primary consideration is either given to the control of abnormal pressure and its isolation weak shallow zones or to the control of salt beds which will tend to flow plastically.

Selection of casing seats for the purpose of pressure control requires a knowledge pore pressure and fracture gradient of the formation to be penetrated. Once information is available, casing setting depth should be determined for the deepest string to be run in the well. Design of successive setting depths can be followed from the bottom string to the surfaces.

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Based on the GTO of a 19000ft deep well, we will develop a mud and casing program and will design individual casings based, in each case, on the assumption of worst possible loading conditions.

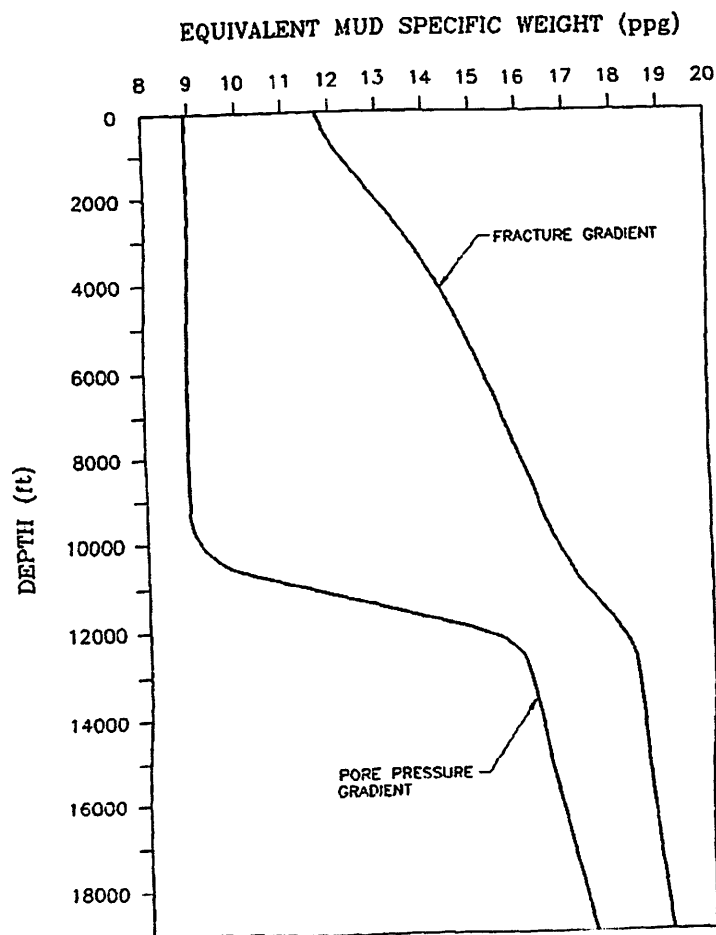


Fig. 3.1 Pore pressure and fracture gradient data for different depths.

Casing for Intermediate Section of the Well

The principle behind the selection of the intermediate casing seat is to first control the formation pressure with drilling fluid hydrostatic pressure without fracturing the shallow formations. Then, once these depths have been established, the differential pressure along the length of the pipe section is checked in order to prevent the pipe from sticking while drilling or running casing.

From the Fig 3.2 the formation pressure gradient at 19,000 ft is 0.907 psi/ft (equivalent mud specific weight = 17.45 lb/gal). To control this pressure, the wellbore pressure gradient must be greater than 0.907 psi/ft. When determining the actual wellbore pressure gradient consideration is given to: trip margins for controlling swab pressure, the equivalent increase in drilling fluid specific weight due to the surge pressure associated with the running of the casing and a safety margin. Generally a factor between 0.025 and 0.045 psi/ft (0.48 to 0.9 lb/gal of equivalent drilling mud specific weight) can be used to take into account the effects of swab and surge and provide a safety factor (Adams, 1985). Thus, the pressure gradient required to control the formation pressure at the bottom of the hole would be $0.907 + 0.025 = 0.932$ psi/ft (17.95 lb/gal). At the same time, formations having fracture gradients less than 0.932 psi/ft must also be protected. Introducing a safety factor of 0.025 psi/ft, the new fracture gradient becomes $0.932 + 0.025 = 0.957$ psi/ft (18.5 lb/gal). The depth at which this fracture gradient is encountered is 14,050 ft. Hence, as a starting point the intermediate casing seat should be placed at this depth.

The next step is to check for the likelihood of pipe-sticking. When running casing pipe sticking is most likely to occur in transition zones between normal pressure and abnormal pressure. The maximum differential pressures at which the casing can be run without severe pipe sticking problems are: 2,000 - 2,300 psi for a normally pressured zone and 3,000 - 3,300 psi for an abnormally pressured zone (Adams, 1985). Thus, if the differential pressure in the minimal pore pressure zone is greater than the arbitrary (2,000 — 2,300 psi) limit, the intermediate casing setting depth needs to be changed.

From Fig. 3.2, it is clear that a drilling mud specific weight of 16.85 lb/gal ($16.35 + 0.5$) would be necessary to drill to a depth of 14,050 ft. The normal pressure zone, 8.9 lb/gal, ends at 9,150 ft where the differential pressure is:

$$9150 (16.85 - 8.9) \times 0.052 = 3,783 \text{ psi}$$

This value exceeds the earlier limit. The maximum depth to which the formation can be drilled and cased without encountering pipe sticking problems can be computed as follows:

$$P = D_n (\lambda_m - \lambda_f) \times 0.052$$

Where,

P arbitrary limit of differential pressure. psi.
 λ_m specific weight of new drilling fluid, lb/gal.
 λ_f specific weight of formation fluid, lb/gal.

Planning & Design of Casing

D_n
0.052

depth where normal pressure zone ends, ft.
conversion factor from lb/gal to psi/ft

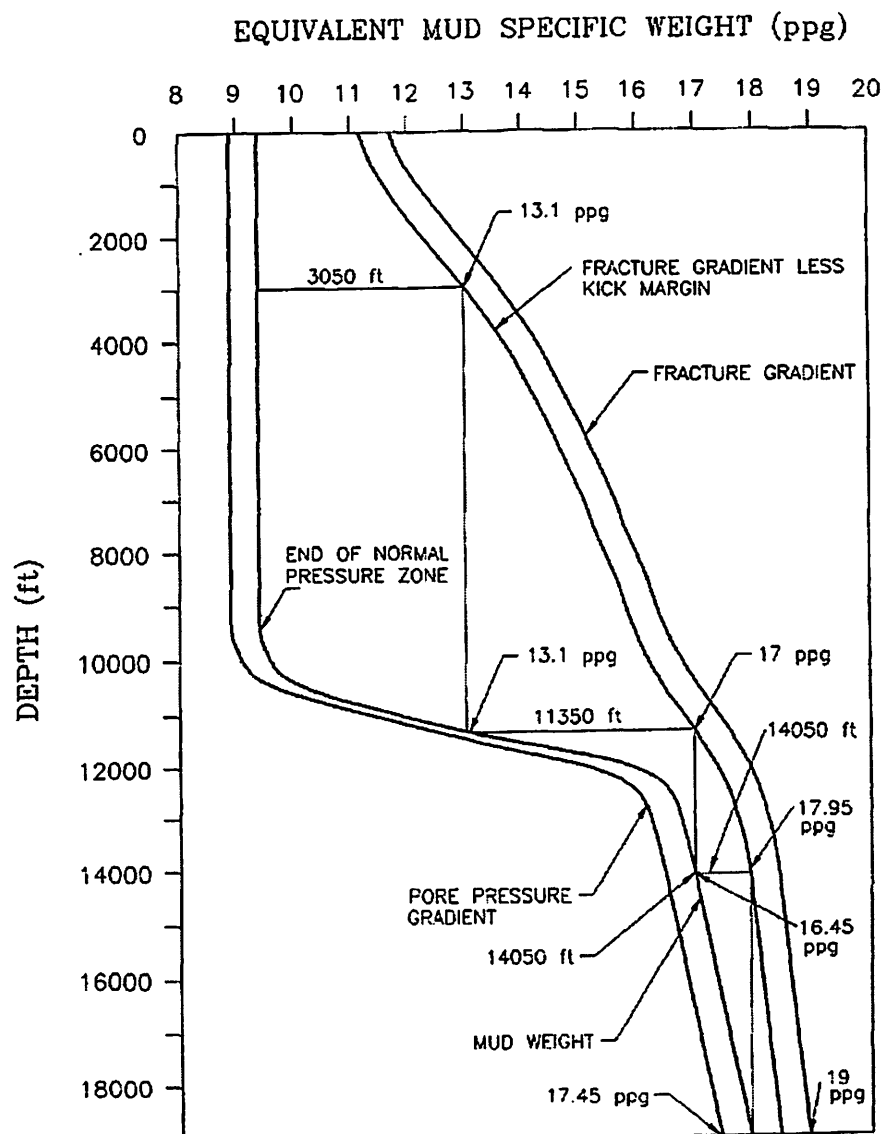


Fig. 3.2: Selection of casing seats based on the pore pressure and fracture gradient.

Given a differential pressure limit of 2,000 psi, the value for the new mud specific weight becomes 13.1 lb/gal (0.681 psi/ft gradient). Now the depth, at which the new drilling fluid gradient becomes the same as the formation fluid gradient, is 11,350 ft. For an additional safety margin in the drilling operation, 11,100 ft is selected as the setting depth for this pipe. The setting depth for casing below the intermediate casing is selected on the basis of the fracture gradient at 11,100 ft. Hence, the maximal drilling fluid pressure

Planning & Design of Casing

gradient that can be used to control formation pressure safely, without creating fractures at a depth of 11,100 ft, must be determined.

From Fig. 3.3, the fracture gradient at 11,100 ft is 0.902 psi/ft (or 17.35 lb/gal equivalent drilling mud weight). Once again, a safety margin of 0.025 psi/ft which takes into account the swab and surge pressures and provides a safety factor is used. This yields a final value for the fracture gradient of 0.877 psi/ft and a mud specific weight of 16.85 lb/gal, respectively. The maximal depth that can be drilled safely with the 16.85 lb/gal drilling fluid is 14,050 ft. Thus, 14,000 ft (or 350 joints) is chosen as the setting depth for the next casing string, insofar as this string does not reach the final target depth, the possibility of setting a liner between 11,100 ft and 14,000 ft should be considered.

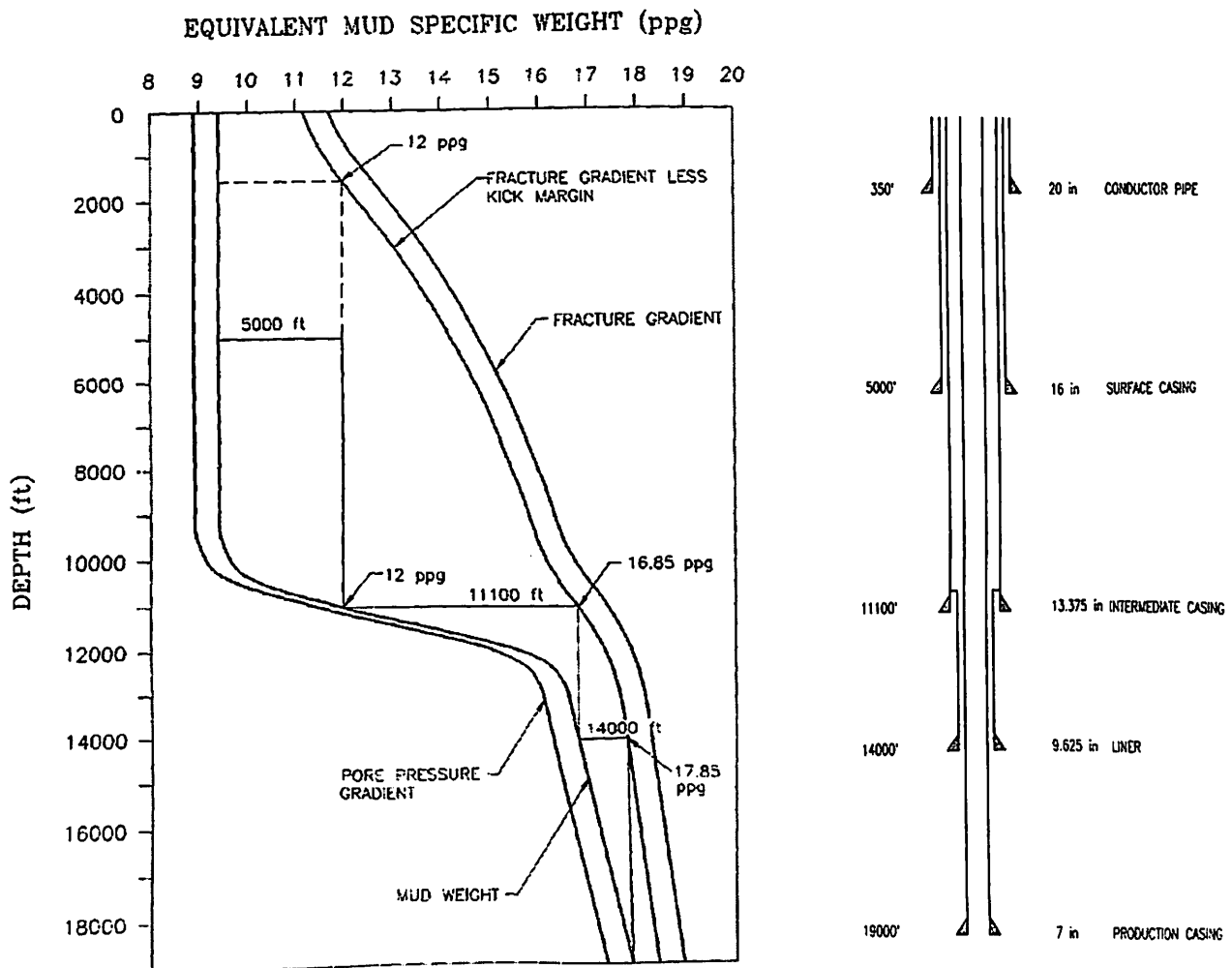


Fig. 3.3: Selection of setting depths for different casings in a 19,000-ft well.

The final selection of the liner setting depth should satisfy the following criteria:

1. Avoid fracturing below the liner setting depth.
2. Avoid differential pipe sticking problems for both the liner and the section below the liner.
3. Minimize the large hole section in which the liner is to be set and thereby reduce the pipe costs.

As was shown in Fig. 3.2, the mud weight that can be used to drill safely to the final depth is 17.95 lb/gal (gradient of 0.93 psi/ft). This value is lower than the fracture gradient at the liner setting depth.

Differential pressures between 11,100 ft and 14,000 ft and between 14,000 ft and 19,000 ft are 821 psi and 451 psi, respectively. These values are within the prescribed limits.

Thus, the final setting depths for intermediate casing string, drilling liner and production casing string of 11,100 ft, 14,000 ft, and 19,000 ft, respectively, are presented in Fig. 3.3. These setting depths also minimize the length of the large hole sections.

3.1.2 Surface Casing String

The surface casing string is often subjected to abnormal pressures due to a kick arising from the deepest section of the hole. If a kick occurs and the shut—in casing pressure plus the drilling fluid hydrostatic pressure exceeds the fracture resistance pressure of the formation at the casing shoe, fracturing or an underground blowout can occur. The setting depth for surface casing should, therefore, be selected so as to contain a kick imposed pressure.

Another factor that may influence the selection of surface casing setting depth is the protection of fresh water aquifers. Drilling fluids can contaminate fresh water aquifers and to prevent this from occurring the casing seat must be below the aquifer. Aquifers usually occur in the range of 2,000 — 5,000 ft.

The relationship between the kick—imposed pressure and depth can be obtained using the data in Fig. 3.1. Consider an arbitrary casing seat at depth D_s the maximal kick—imposed pressure at this point can be calculated using the following relationship:

$$P_k = G_{pf} D_i - G_{pf} (D_i - D_s) \quad (3.2)$$

where:

P_k	=	kick imposed pressure at depth D , psi.
D_s	=	setting depth for surface casing, ft.

Planning & Design of Casing

D_i = setting depth for intermediate casing, ft.

G_{pf} = formation fluid gradient at depth D , psi/ft.

Assume also that formation fluid enters the hole from the next casing setting depth, D_i . Expressing the kick—imposed pressure of the drilling fluid in terms of formation fluid gradient and a safety margin, SM , Eq. 3.2 becomes:

$$p_k = (G_{pf} + SM)D_i - G_{pf}(D_i - D_s) \quad (3.3)$$

Or

$$\frac{p_k}{D_s} = SM \left(\frac{D_i}{D_s} \right) + G_{pf} \quad (3.4)$$

Where p_k/D is the kick—imposed pressure gradient at the seat of the surface casing and must be lower than the fracture resistance pressure at this depth to contain the kick.

Now, assume that the surface casing is set to a depth of 1,500 ft and SM , in terms of equivalent mud specific weight, is 0.5 lb/gal. The kick—imposed pressure gradient can be calculated as follows:

$$\begin{aligned} \frac{p_k}{1,500} &= \left(0.052 \times 0.5 \left(\frac{11,100}{1,500} \right) + 8.9 \times 0.052 \right) \\ &= 0.6552 \text{ psi/ft} \end{aligned}$$

The fracture gradient at 1,500 ft is 0.65 psi/ft (12.49 lb/gal). Clearly, the kick imposed pressure is greater than the strength of the rock and, therefore, a deeper depth must be chosen. This trial-and error process continues until the fracture gradient exceeds the kick—imposed pressure gradient. Values for different setting depths and their corresponding kick—imposed fracture and pressure gradients are presented below:

Table 3.1: Fracture and kick—imposed pressure gradients vs depth.

Depth (ft)	Kick-imposed pressure gradient (psi/ft)	Fracture pressure gradient (psi/ft)
1,500	0.6552	0.65
2,000	0.61	0.66

At a depth of 2,000 ft the fracture resistance pressure exceeds the kick—imposed pressure and so 2,000 ft could be selected as a surface casing setting depth. However, as most fresh-water aquifers occur between 2,000 and 5,000 ft the setting depth for surface

casing should be within this range to satisfy the dual requirements of prevention of underground blowouts and the protection of fresh-water aquifers.

3.1.3 Conductor Pipe

The selection of casing setting depth above surface casing is usually determined by drilling problems and the protection of water aquifers at shallow depths. Severe lost circulation zones are often encountered in the interval between 100 and 1,000 ft and are overcome by covering the weak formations with conductor pipes. Other factors that may affect the setting depth of the conductor pipe are the presence of unconsolidated formations and gas traps at shallow depths.

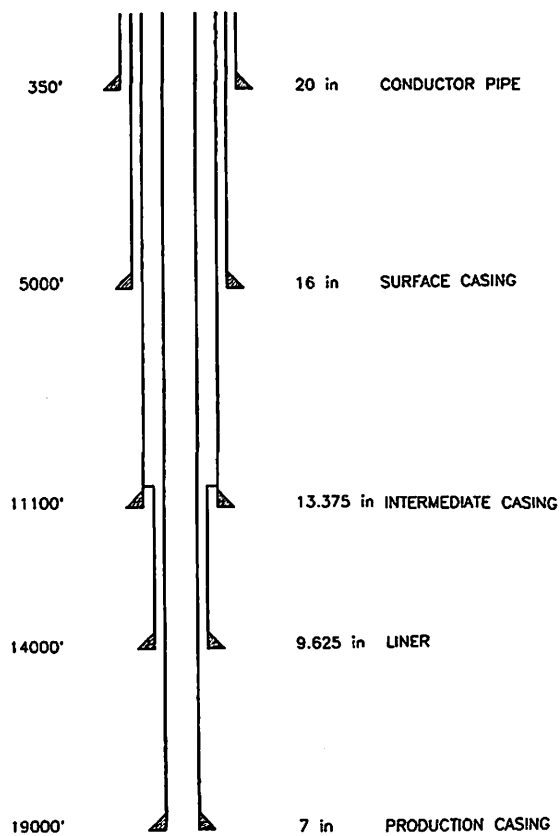


Fig. 3.5: Casing program for a typical 19,000-ft deep well.

3.2 CASING STRING SIZES

Selection of casing string sizes is generally controlled by three major factors:

- (1) Size of production tubing string
- (2) Number of casing strings required to reach the final depth
- (3) Drilling conditions.

3.2.1 Production Tubing String

The size of the production tubing string plays a vital role in conducting oil and gas to the surface at an economic rate. Small—diameter tubing and subsurface control equipment always restrict the flow rate due to the high frictional pressure losses. Completion and workover operations can be even more complicated with small diameter production tubing and casing strings because the reduced inside diameter of the tubing and the annular space between the casing and tubing make tool placement and operation very difficult. For these reasons, large—diameter production tubing and casing strings are always preferable.

3.2.2 Number of Casing Strings

The number of casing strings required to reach the producing formation mainly depends on the setting depth and geological conditions as discussed previously. Past experience in the petroleum industry has led to the development of fairly standard casing programs for different depths and geological conditions. Figure 3.4 presents six of these standard casing programs.

3.2.3 Drilling Conditions

Drilling conditions that affect the selection of casing sizes are: bit size required to drill the next depth, borehole hydraulics and the requirements for cementing the casing.

Drift diameter of casing is used to select the bit size for the hole to be drilled below the casing shoe. Thus, the drift diameter or the bit size determines the maximal outside diameter of the successive casing strings to be run in the drilled hole. Bits from different manufacturers are available in certain standard sizes according to the IADC (International Association of Drilling Contractors). Almost all API casing can be placed safely without pipe sticking in holes drilled with these standard bits. Non—API casing, such as thick-wall casing is often required for completing deep holes. The drift diameter of thick-wall pipe may restrict the use of standard bit sizes though additional bit sizes are available from different manufacturers for use in such special circumstances.

The size of the annulus between the drillpipe and the drilled hole plays an important role in cleaning the hole and maintaining a gauge hole. Hole cleaning is the ability of the drillbug fluid to remove the cuttings from the annulus and depends mainly on the drilling fluid viscosity, annular fluid velocity, and cutting sizes and shapes. Annular velocity is reduced if the annulus is too large and as a consequence, hole cleaning becomes inadequate. Large hole sections occur in the shallow portion of the well and obviously it

is here that the rig pumps must deliver the maximum flow rate. Most rig pumps are rated to 3,000 psi though they generally reach maximum flow rate before rated pressure even when operating two pumps together. Should the pumps be unable to clean the surface portion of the hole because they lack adequate capacity then a more viscous drilling fluid will need to be used to support the cuttings.

With increasing depth, the number of casing strings in the hole increases and the hole narrows as does the annular gap between the hole and the casing. Fluid flow in such narrow annular spaces is turbulent and tends to enlarge the hole sections which are sensitive to erosion. In an enlarged hole section, hole cleaning is very poor and a good cementing job becomes very difficult.

Annular space between the casing string and the drilled hole should be large enough to accommodate casing appliances such as centralizers and scratchers, and to avoid premature hydration of cement. An annular clearance of 0.75 in. is sufficient for cement slurry to hydrate and develop adequate strength. Similarly, a minimum clearance of 0.375 in. (0.750 in. is preferable) is required to reach the recommended strength of bonded cement (Adams, 1985).

In summary, the selection of casing sizes is a critical part of casing design and must begin with consideration of the production casing string. The pay zone can be analyzed with respect to the flow potential and the drilling problems which are expected to be encountered in reaching it. Assuming a production casing string of 7 in outside diameter, which satisfies both production and drilling requirements, a casing program for a typical 19,000-ft deep well is presented in Fig. 3.5.

Table 3.2 presents the drilling fluid program, pore pressures and fracture gradients encountered at the different setting depths.

Planning & Design of Casing

Table 3.2: Typical drilling and mud programs for a 19,000-ft well.

Drilling program:

0 – 350 ft	→	26-in. hole
350 – 5,000 ft	→	20-in. hole
5,000 – 11,100 ft	→	17.5-in. hole
11,100 – 14,000 ft	→	12.5-in. hole
14,000 – 19,000 ft	→	8.5-in. hole

Casing program

0 – 350 ft	→	20-in.	conductor pipe
0 – 5,000 ft	→	16-in.	surface casing
0 – 11,100 ft	→	13.375-in.	intermediate casing
11,100 – 14,000 ft	→	9.625-in.	liner
0 – 19,000 ft	→	7-in.	production casing

Formation fluid gradient

0 – 350 ft	→	0.465 psi/ft
350 – 5,000 ft	→	0.465 psi/ft
5,000 – 11,100 ft	→	0.597 psi/ft
11,100 – 14,000 ft	→	0.849 psi/ft
14,000 – 19,000 ft	→	0.906 psi/ft

Mud program

0 – 350 ft	→	9.5 ppg (70.7 lb/ft ³)
0 – 5,000 ft	→	9.5 ppg (70.7 lb/ft ³)
0 – 11,100 ft	→	12.0 ppg (89.8 lb/ft ³)
0 – 14,000 ft	→	16.8 ppg (125.7 lb/ft ³)
0 – 19,000 ft	→	17.9 ppg (133.9 lb/ft ³)

3.3 SELECTION OF CASING WEIGHT, GRADE AND COUPLINGS

After establishing the number of casing strings required to complete a hole, their respective setting depths and the outside diameters, one must select the nominal weight, steel grade, and couplings of each of these strings. In practice each casing string is designed to withstand the maximal load that is anticipated during casing landing, drilling, and production operations (Prentice, 1970).

Often, it is not possible to predict the tensile, collapse, and burst loads during the life of the casing. For example, drilling fluid left in the annulus between the casing and the drilled hole deteriorates with time. Consequently, the pressure gradient may be reduced to that of salt water which can lead to a significant increase in burst pressure. The casing design therefore, proceeds on the basis of the worst anticipated loading conditions throughout the life of the well.

Performance properties of the casing deteriorate with time due to wear and corrosion. A safety factor is used therefore, to allow for such uncertainties and to ensure that the rated performance of the casing is always greater than the expected loading. Safety factors vary according to the operator and have been developed over many years of drilling and production experience. According to Rabia (1987), common safety factors for the three principal loads are: 0.85 - 1.125 for collapse, 1 - 1.1 for burst and 1.6—1.8 for tension.

Maximal load concept tends to make the casing design very expensive. Minimal cost can be achieved by using a combination casing string—a casing string with different nominal weights, grades and couplings. By choosing the string with the lowest possible weight per foot of steel and the lowest coupling grades that meet the design load conditions, minimal cost is achieved.

Design load conditions vary from one casing string to another because each casing string is designed to serve a specific purpose. In the following sections general methods for designing each of these casing strings (conductor pipe, surface casing, intermediate casing, production casing and liner) are presented.

Casing-head housing is generally installed on the conductor pipe. Thus, conductor pipe is subjected to a compressional load resulting from the weight of subsequent casing strings. Hence, the design of the conductor pipe is made once the total weight of the successive casing strings is known.

It is customary to use a graphical technique to select the steel grade that will satisfy the different design loads. This method was first introduced by Goins et al. (1965, 1966) and later modified by Prentice (1970) and Rabia (197). In this approach, a graph of loads (collapse or burst) versus depth is first constructed then the strength values of available steel grades are plotted as vertical lines. Steel grades which satisfy the maximal existing load requirements of collapse and burst pressures are selected.

Planning & Design of Casing

Design load for collapse and burst should be considered first. Once the weight grade, and sectional lengths which satisfy burst and collapse loads have been determined, the tension load can be evaluated and the pipe section can be upgraded if it is necessary. The final step is to check the biaxial effect on collapse and burst loads, respectively. If the strength in any part of the section is lower than the potential load, the section should be upgraded and the calculation repeated.

In the following sections, a systematic procedure for selecting steel grade weight Coupling and sectional length is presented.

Table 3.3 presents the available steel grades and couplings and related performance properties for expected pressures s listed in Table 3.2.

Table 3.3: Available steel grades, weights and coupling types and their minimum performance properties available for the expected pressures.

Size, outside diameter (in.)	Nominal weight, threads and coupling (lb/ft)	Grade	Pipe		Pipe collapse resistance (psi)	Body yield strength (1000 lbf)	Coupling type	Internal pressure resistance (psi)	Joint strength (1000 lbf)
			Wall thickness (in.)	Inside diameter (in.)					
20	94	K-55	0.438	19.124	520	1,480	LTC	2,110	955
	133	K-55	0.635	18.730	1,500	2,125	BTC	3,036	2,123
16	65	K-55	0.375	15.250	630	1,012	STC	2,260	625
	75	K-55	0.438	15.124	1,020	1,178	STC	2,630	752
	84	L-80	0.495	15.010	1,480	1,929	BTC	4,330	1,861
13 ³ / ₈	109	K-55	0.656	14.688	2,560	1,739	BTC	3,950	1,895
	98	L-80	0.719	11.937	5,910	2,800	BTC	7,530	2,286
	85	P-110	0.608	12.159	4,690	2,682	PTC	8,750	2,290
9 ⁵ / ₈	98	P-110	0.719	11.937	7,280	3,145	PTC	10,350	2,800
	58.4	L-80	0.595	8.435	7,890	1,350	BTC	8,650	1,396
	47	P-110	0.472	8.681	5,310	1,493	LTC	9,440	1,213
7	38	V-150	0.540	5.920	19,240	1,644	Extreme-line	18,900	1,430
	41	V-150	0.590	5.820	22,810	1,782	PTC	20,200	1,052
	46	V-150	0.670	5.660	25,970	1,999	PTC	25,070	1,344
	38	MW-155	0.540	5.920	19,700	1,697	Extreme-line	20,930	1,592
	46	SOO-140	0.670	5.660	24,230	865	PTC	23,400	1,222
	46	SOO-155	0.670	5.660	26,830	2,065	PTC	25,910	1,344

LTC = long thread coupling, STC = short thread coupling, BTC = buttress thread coupling, and PTC = proprietary coupling.

3.3.1 Surface Casing (16-in.)

Surface casing is set to a depth of 5,000 ft and cemented back to the surface. Principal loads to be considered in the design of surface casing are: collapse, burst, tension and biaxial effects. Inasmuch as the casing is cemented back to the surface, the effect of buckling is ignored.

Collapse

Collapse pressure arises from the differential pressure between the hydrostatic heads of fluid in the annulus and the casing, it is a maximum at the casing shoe and zero at the surface. The most severe collapse pressures occur if the casing is run empty or if a lost circulation zone is encountered during the drilling of the next interval.

At shallow depths, lost circulation zones are quite common. If a severe lost-circulation zone is encountered near the bottom of the next interval and no other permeable formations are present above the lost-circulation zone, it is likely that the fluid level could fall below the casing shoe, in which case the internal pressure at the casing shoe falls to zero (complete evacuation). Similarly, if the pipe is run empty, the internal pressure at the casing shoe will also be zero.

At greater depths, complete evacuation of the casing due to lost circulation is never achieved. Fluid level usually drops to a point where the hydrostatic pressure of the drilling fluid inside the casing is balanced by the pore pressure of the lost circulation zone.

Surface casing is usually cemented to the surface for several reasons, the most important of which is to support weak formations located at shallow depths. The presence of a cement sheath behind the casing improves the collapse resistance by up to 23% (Evans and Herriman, 1972) though no improvement is observed if the cement sheath has voids. In practice it is almost impossible to obtain a void-free cement-sheath behind the casing and, therefore, a saturated salt-water gradient is assumed to exist behind the cemented casing to compensate for the effect of voids on collapse strength. Some designers ignore the beneficial effect of cement and instead assume that drilling fluid is present in the annulus in order to provide a built-in safety factor in the design.

In summary, the following assumptions are made in the design of collapse load for surface casing (see Fig. 3.6(a)):

1. The pressure gradient equivalent to the specific weight of the fluid outside the pipe is that of the drilling fluid in the well when the pipe was run.
2. Casing is completely empty.
3. Safety factor for collapse is 0.85.

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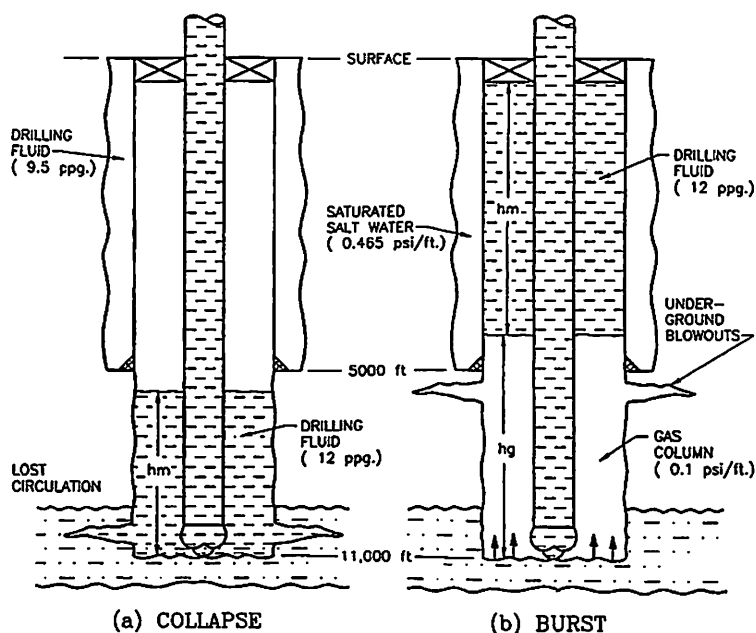


Fig. 3.6: Collapse and burst load on surface casing.

Collapse pressure at the surface = 0 psi

Collapse pressure at the casing shoe:

$$\begin{aligned}
 \text{Collapse pressure} &= \text{external pressure} - \text{internal pressure} \\
 &= G_{pm} \times 5,000 - 0 \\
 &= 9.5 \times 0.052 \times 5,000 - 0 \\
 &= 2,470 \text{ psi}
 \end{aligned}$$

In Fig. 3.7, the collapse line is drawn between 0 psi at the surface and 2,470 psi at 5,000ft. The collapse resistances of suitable grades from Table 3.3 are presented below.

Collapse resistances for the above grades are plotted as vertical lines in Fig: 3.7 the points at which these lines intersect the collapse load line are the maximal depths for which the individual casing grade would be suitable. Hence, based collapse load, the grades of steel that are suitable for surface casing are given Table 3.5.

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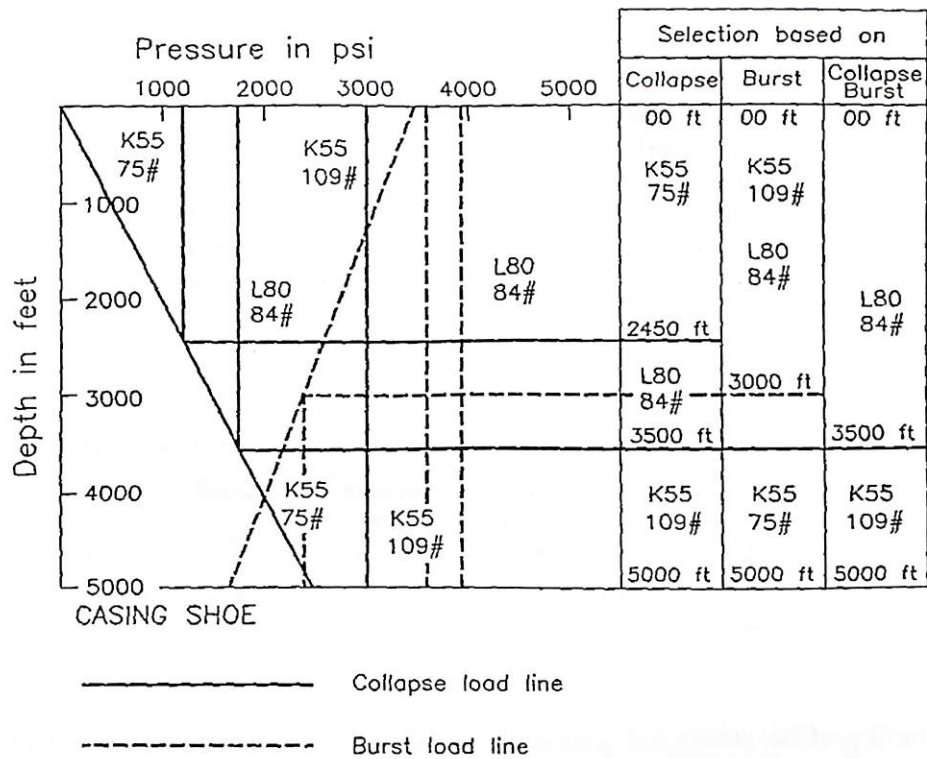


Fig. 3.7: Selection of steel grade and weight based on the collapse and burst load for 16-in. surface casing.

Burst

The design for burst load assumes a maximal formation pressure results from a kick during the drilling of the next hole section. A gas kick is usually considered to simulate the worst possible burst load. At shallow depths it is assumed that the influx of gas displaces the entire column of drilling fluid and thereby subjects the casing to the kick—imposed pressure. At the surface the annular pressure is zero and consequently burst pressure is a maximum at the surface and a minimum at the shoe.

For a long section, it is most unlikely that the inflowing gas will displace the entire column of drilling fluid. According to Bourgoyne et al. (1985), burst design for a long section of casing should be such as to ensure that the kick imposed pressure exceeds the formation fracture pressure at the casing seat before the burst rating of the casing is reached. In this approach, formation fracture pressure is used as a safety pressure release mechanism so that casing rupture and consequent loss of human lives and property are prevented. The design pressure at the casing seat is assumed to be equal to the fracture pressure plus a safety margin to allow for an injection pressure: the pressure required to inject the influx fluid into the fracture.

Planning & Design of Casing

Table 3.4: Collapse resistance of grades suitable for surface casing.

Grade	Weight (lb/ft)	Coupling	Collapse resistance (psi)	
			$SF = 1$	$SF = 0.85$
K-55	75	STC	1,020	1,200
L-80	84	STC/BTC	1,480	1,741
K-55	109	BTC	2,560	3,012

Table 3.5: Intervals for surface casing based on collapse loading.

Section	Interval (ft)	Grade and Weight (lb/ft)	Length (ft)
1	0 - 2,450	K-55, 75	2,450
2	2,450 - 3,550	L-80, 84	1,100
3	3,550 - 5,000	K-55, 109	1,450

Burst pressure inside the casing is calculated assuming that all the drilling fluid inside the casing is lost to the fracture below the casing seat leaving the influx fluid in the casing. The external pressure on the casing due to the annular drilling fluid helps to resist the burst pressure; however, with time, drilling fluid deteriorates and its specific weight drops to that of saturated salt water. Thus, the beneficial effects of drilling fluid and the cement sheath behind the casing are ignored and a normal formation pressure gradient is assumed when calculating the external pressure or back-up pressure outside the casing.

The following assumptions are made in the design of strings to resist burst loading (See Fig. 3.6(b)):

1. Burst pressure at the casing seat is equal to the injection pressure.
2. Casing is filled with influx gas.
3. Saturated salt water is present outside the casing.
4. Safety factor for burst is 1.1.

Burst pressure at the casing seat = injection pressure — external pressure, P_o , at 5,000ft.

Injection pressure = (fracture pressure + safety factor) x 5,000

Again, it is customary to assume a safety factor of 0.026 psi/ft (or equivalent drilling fluid specific weight of 0.5 ppg).

Planning & Design of Casing

$$\begin{aligned}
 \text{Injection pressure} &= (14.76 + 0.5) 0.052 \times 5,000 \\
 &= 3,976.6 \text{ psi} \\
 \\
 \text{External pressure at 5,000 ft} &= \text{saturated salt water gradient} \times 5,000 \\
 &= 0.465 \times 5,000 \\
 &= 2,325 \text{ psi} \\
 \\
 \text{Burst pressure at 5,000 ft} &= 3,976.6 - 2,325 \\
 &= 1,651.6 \text{ psi} \\
 \\
 \text{Burst pressure at the surface} &= \text{internal pressure} - \text{external pressure} \\
 \\
 \text{Internal pressure} &= \text{injection pressure} - G_{pg} \times 5,000 \\
 &= 3,976.6 - 500 \\
 &= 3,476.6 \text{ psi} \\
 \\
 \text{There:} \\
 G_{pg} &= 0.1 \text{ psi/ft} \\
 \\
 \text{Burst pressure at the surface} &= 3,476.6 - 0 \\
 &= 3,476.6 \text{ psi}
 \end{aligned}$$

In Fig. 3.7, the burst load line is drawn between 3,476.6 psi at the surface and 1651.6 psi at a depth of 5,000 ft. The burst resistances of suitable grades are presented in Table 3.6.

Table 3.6: Burst resistance of grades suitable for surface casing.

Grade	Weight (lb/ft)	Coupling	Burst resistance (psi)	
			$SF = 1$	$SF = 1.1$
K-55	75	STC	2,630	2,391
L-80	84	STC/BTC	4,330	3,936
K-55	109	BTC	3,950	3,591

The burst resistances of the above grades are also plotted as vertical lines in Fig. 3.7. The point of intersection of the load line and the resistance line represents the maximal depth for which the individual grades would be most suitable. According to their burst resistances the steel grades that can be selected for surface casing are shown in Table 3.7.

Table 3.7: Intervals for surface casing grades based on burst loading.

Section	Depth (ft)	Grade and Weight (lb/ft)	Length (ft)
1	3,000 – 5,000	K-55, 75	2,000
2	0 – 3,000	L-80, 84	3,000
3	0 – 3,000	K-55, 109	3,000

Selection Based on Both Collapse and Burst Pressures

When the selection of casing is based on both collapse and burst pressures (see Fig. 3.7), one observes that:

1. Grade K-55 (75 lb/ft) satisfies the collapse requirement to a depth of 2,450 ft, but does Not satisfy the burst requirement.
2. Grade L-80 (84 lb/ft) satisfies burst requirements from 0 to 5,000 ft but only satisfies The collapse requirement from 0 to 3,550 ft.
3. Grade K-55 (109 lb/ft) satisfies both collapse and burst requirements from 0 to 5,000 ft.
4. Steel grade K-55 (75 lb/ft) can be rejected because it does not simultaneously satisfy collapse and burst resistance criteria across any section of the hole.

For economic reasons, it is customary to initially select the lightest steel grade because weight constitutes a major part of the cost of casing. Thus, the selection of casing grades based on the triple requirements of collapse, burst, and cost is summarized in Table 3.8.

Table 3.8: Most economical surface casing based on collapse and burst loading.

Section	Interval (ft)	Grade and Weight (lb/ft)	Coupling	Length (ft)
1	0 – 3,550	L-80, 84	BTC	3,550
2	3,550 – 5,000	K-55, 109	BTC	1,450

Tension

As discussed, the principal tensile forces originate from pipe weight, bending load, shock loads and pressure testing. For surface casing, tension due to bending of the pipe is usually ignored.

In calculating the buoyant weight of the casing, the beneficial effects of the buoyancy force acting at the bottom of the string have been ignored. Thus the neutral point is effectively considered to be at the shoe until buckling effects are considered.

The tensile loads to which the two sections of the surface casing are subjected are presented in Table 3.9. The value of $Y_p = 1.861 \times 10^3$ lbf (Column (7)) is the joint yield strength which is lower than the pipe body yield strength of $1,929 \times 10^3$ lbf.

Table 3.9: Total tensile loads on surface casing string.

(1) Depth interval (ft)	(2) Grade and Weight (lb/ft)	(3) Buoyant weight of section joint (1,000 lbf) $(1) \times W_n \times BF (=0.856)$	(4) Cumulative buoyant weight carried by the top joint (1,000 lbf)
5,000 - 3,550	K-55, 109	135.222	135.222
3,550 - 0	L-80, 84	255.130	390.352

(5) Shock load carried by each section (1,000 lbf) $3,200W_n$	(6) Total tension (1,000 lbf) (4) + (5)	(7) $SF = \frac{Y_p}{\text{Total tension}}$
348.8	484.022	$1,738/484.022 = 3.59$
268.8	659.152	$1,861/659.152 = 2.82$

It is evident from the above that both sections satisfy the design requirements for tensional load arising from cumulative buoyant weight and shock load.

Pressure Testing and Shock Loading

During pressure testing, extra tensional load is exerted on each section. Thus, sections with marginal safety, factors should be checked for pressure testing conditions.

Tensional load due to pressure testing

$$\begin{aligned} &= \text{burst resistance of weakest grade (L80, 84)} \times 0.6 \times A_s \\ &= 4,330 \times 0.6 \times 24.1 \\ &= 62,611.8 \text{ lbf} \end{aligned}$$

Total tensional load during pressure testing

$$= \text{cumulative buoyant load} + \text{load due to pressure testing}$$

Shock loading occurs during the running of casing, whereas pressure testing occurs after the casing is in place; thus, the affects of these additional tensional forces are considered separately. The larger of the two forces is added to the buoyant and bending forces which remain the same irrespective of whether the pipe is in motion or static.

Hence,

$$\begin{aligned} \text{SF} &= Y_p / \text{Total tension load} \\ &= 1,861,000 / 62,611.8 + 390,352 \\ &= 4.11 \end{aligned}$$

This indicates that the top joint also satisfies the requirement for pressure testing.

Biaxial Effects

It was shown previously that the tensional load has a beneficial effect on burst pressure and a detrimental effect on collapse pressure. It is, therefore, important to check the collapse resistance of the top joint of the weakest grade of the selected casing and compare it to the existing collapse pressure. In this case, L-80 (84 lb/ft) is the weakest grade. Reduced collapse resistance of this grade can be calculated as follows:

Buoyant weight carried by L-80 (84 lb/ft) = 135,222 lbf.

(1) Axial stress due to the buoyant weight is equal to:

$$\begin{aligned} \sigma_a &= \frac{135,222}{\pi(d_o^2 - d_i^2)/4} \\ &= \frac{135,222}{\pi(16^2 - 15^2)/4} \\ &= 5,608 \text{ psi} \end{aligned}$$

(2) Yield stress is equal to:

$$\begin{aligned}\sigma_y &= \frac{1,929,000}{\pi(16^2 - 15^2)/4} \\ &= 80,000 \text{ psi}\end{aligned}$$

(3) The effective yield stress is given by:

$$\begin{aligned}\sigma_e &= \sigma_y \left\{ \left[1 - 0.75 \left(\frac{\sigma_a}{\sigma_y} \right)^2 \right]^{0.5} - 0.5 \left(\frac{\sigma_a}{\sigma_y} \right) \right\} \\ &= 80,000 \left\{ \left[1 - 0.75 \left(\frac{5,608}{80,000} \right)^2 \right]^{0.5} - 0.5 \left(\frac{5,608}{80,000} \right) \right\} \\ &= 77,048 \text{ psi}\end{aligned}$$

$$(4) d_0/t = 16/0.495 = 32.32$$

(5) The values of A, B, C, F and C are calculated using equations in Table 2.1 and the value of σ_e (as determined above, i.e., 77,048 psi) as:

$$\begin{aligned}A &= 3.061 \\ B &= 0.065 \\ C &= 1,867 \\ F &= 1.993 \\ C &= 0.0425\end{aligned}$$

6) Collapse failure mode ranges can be calculated as follows (Table 2.1):

$$\begin{aligned}\frac{[(A - 2)^2 + 8(B + C/\sigma_e)]^{0.5} + (A - 2)}{2(B + C/\sigma_e)} &= 13.510 \\ \frac{\sigma_e(A - F)}{C + \sigma_e(B - G)} &= 22.724 \\ \frac{2 + B/A}{3B/A} &= 31.615\end{aligned}$$

Inasmuch as the value of d_0/t is greater than 3 1.615, the failure mode of collapses in the elastic region. For elastic collapse, collapse resistance is not a function of yield strength and, therefore, the collapse resistance remains unchanged in the presence of imposed axial load.

Final Selection

Both Section 1 and Section 2 satisfy the requirements for the collapse, burst and tensional load. Thus, the final selection is shown in Table 3.10.

Table 3.10: Final casing selection for surface string.

Section	Depth (ft)	Grade and Weight (lb/ft)	Length (ft)
1	0 - 3,550	L-80, 84	3,550
2	3,550 - 5,000	K-55, 109	1,450

3.3.2 Intermediate Casing (13-in. pipe)

Intermediate casing is set to depth of 11,100 ft and partially cemented at the casing seat. Design of this string is similar to the surface—string except that some of the design loading conditions are extremely severe. Problems of lost circulation, abnormal formation pressure, or differential pipe sticking determines the loading conditions and hence the design requirements. Similarly, with or partial cementing of the string it is now important to include the effect of buckling in the design calculations. Meeting all these requirements makes implementing - the intermediate casing design very expensive.

Below the intermediate casing, a liner is set to a depth of 14,000 ft and as a result the intermediate casing is also exposed to the drilling conditions below the liner. In determining the collapse and burst loads for this pipe, the liner is consider to be the integral part of the intermediate casing as shown in Fig. 3.8.

Collapse

As in the case of surface casing, the collapse load for intermediate casing imposed by the fluid in the annular space, which is assumed to be the heavier drilling fluid encountered by the pipe when it is run in the hole. As discussed previously, maximal collapse load occurs if lost circulation is anticipated in the next drilling interval of the hole and the fluid level falls below the casing seat. This assumption can only be satisfied for pipes set at shallow depths.

In deeper sections of the well, lost circulation causes the drilling fluid level to drop to a point where the hydrostatic pressure of the drilling fluid column balanced by the pore pressure of the lost circulation zone, which is assumed to be saturated salt water gradient of 0.465 psi/ft. Lost circulation is most likely to occur below the casing seat because the fracture resistance pressure at this depth is a minimum.

For collapse load design, the following assumptions are made (Fig. 3.8):

1. A lost circulation zone is encountered below the liner seat (14,000 ft).
2. Drilling fluid level falls by h_a , to a depth of h_m .
3. Pore pressure gradient in the lost circulation zone is 0.465 psi/ft (equivalent mud weight 8.94 ppg).

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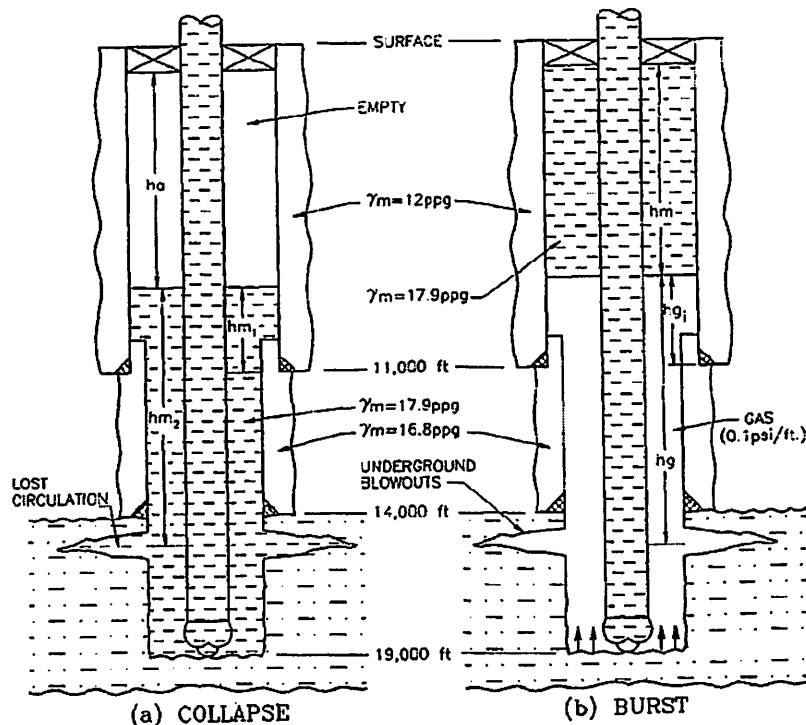


Fig. 3.8: Collapse and burst loads on intermediate casing and liner.

Thus, the design load for collapse can be calculated as follows:

Collapse pressure at surface	= 0 psi
Collapse pressure at casing seat	= external pressure - internal pressure
External pressure	= $G_{pm} \times 11,100$
	= $12 \times 0.052 \times 11,100$
	= 6,926.4 psi

Where;

h_{m2} = the height of the drilling fluid level above the casing seat.

The top of the fluid column from the liner seat can be calculated as follows:

$$h_{m2} = \frac{G_{pf} \times 14,000}{\gamma_m \times 0.052} = \frac{0.465 \times 14,000}{17.9 \times 0.052} = 6,994 \text{ ft}$$

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The distance between the top of the fluid column and the surface, h_a is equal to:

$$\begin{aligned} h_a &= 14,000 - 6,994 \\ &= 7,006 \text{ ft} \end{aligned}$$

Height of the drilling fluid column above the casing seat, h_{ml} , is equal to:

$$\begin{aligned} h_{ml} &= 11,100 - 7,006 \\ &= 4,094 \text{ ft} \end{aligned}$$

Hence, the internal pressure at the casing seat is:

$$\begin{aligned} \text{Internal pressure} &= G_{pm} \times h_{ml} \\ &= 17.9 \times 0.052 \times 4,094 \\ &= 3,810.7 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{Collapse pressure at 11,100 ft} &= 6,926.4 - 3,810.7 \\ &= 3,115.7 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{Collapse pressure at 7,006 ft} &= \text{external pressure} - \text{internal pressure} \\ &= 12 \times 0.052 \times 7,006 - 0 \\ &= 4,371.74 \text{ psi} \end{aligned}$$

In Fig. 3.9, the collapse line is constructed between 0 psi at the surface, 4,371.74 psi at a depth of 7,006 ft and 3,115.7 psi at 11,100 ft. The collapse resistances of suitable steel grades from Table 3.2 are given in Table 3.11 and it is evident that all the steel grades satisfy the requirement for the conditions of maximal design load (4,371.74 psi at 7,006 ft).

Table 3.11: Collapse resistance of grades suitable for intermediate casing.

Grade	Weight (lb/ft)	Coupling	Collapse resistance (psi)	
			$SF = 1$	$SF = 0.85$
L-80	98	BTC	5,910	6,953
P-110	85	PTC	4,690	5,517
P-110	98	PTC	7,280	8,564

Burst

The design load for intermediate casing is based on loading assumed to occur during a gas kick. The maximal acceptable loss of drilling fluid from the casing is limited to an amount which will cause the internal pressure of the casing to rise to the operating condition of the surface equipment (blowout preventers, choke manifolds, etc.). One should not design a string which has a higher working pressure than the surface equipment, because the surface equipment must be able to withstand any potential blowout. Thus, the surface burst pressure is generally set to the working pressure rating of the surface equipment used. Typical operating pressures of surface equipment are 5,000, 10,000, 15,000 and 20,000 psi.

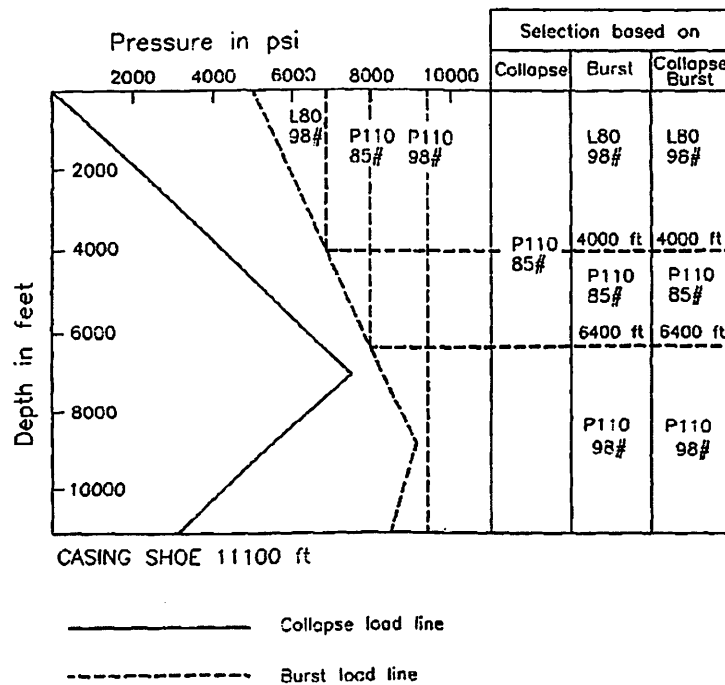


Fig. 3.9: Selection of casing grades and weights based on collapse and burst loads for intermediate casing.

The relative positions of the influx gas and the drilling fluid in the casing are also important (Fig. 3.10). If the influx gas is on the top of the drilling fluid, the load line is represented by a dashed line. If instead the mud is on the top, the load line is represented by the solid line. From the plot, it is evident that the assumption of mud on top of gas yields a greater burst load than for gas on top of mud.

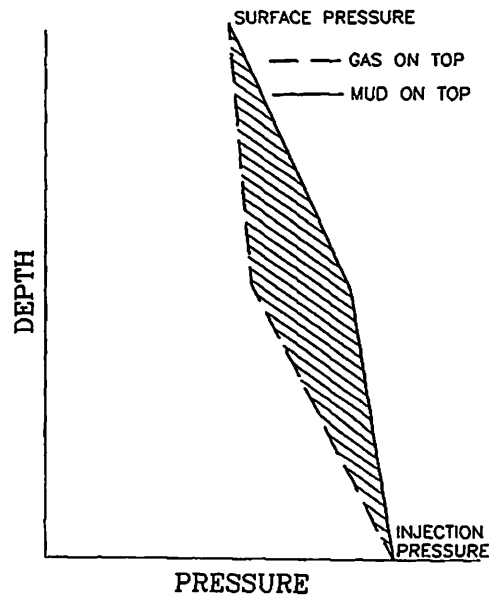


Fig. 3.10: Burst load with respect to the relative position of the drilling fluid and the influx gas.

The following assumptions are made in calculating the burst load:

1. Casing is partially filled with gas.
2. During a gas kick, the gas occupies the bottom part of the hole and the remaining drilling fluid the top.
3. Operating pressure of the surface equipment is 5,000 psi.

Thus, the burst pressure at the surface is 5,000 psi.

Burst pressure at the casing seat = internal pressure - external pressure.

The internal pressure is equal to the injection pressure at the casing seat. The intermediate casing, however, will also be subjected to the kick imposed pressure assumed to occur during the drilling of the final section of the hole. Thus, determination of the internal pressure at the seat of the intermediate casing should be based on the injection pressure at the liner seat.

Injection pressure at the liner seat (14,000 ft)
 = fracture gradient x depth
 = (18.4 + 0.5) x 0.052 x 14,000
 = 13,762 psi.

The relative positions of the gas and the fluid can be determined as follows (Fig.3.8)

$$14,000 = h_g + h_m \quad (3.5)$$

$$\text{Surface pressure} = \text{injection pressure} - (G_{pg}h_g + G_{pm}h_m)$$

$$5,000 = 13,762 - (0.1 \times h_g + 17.9 \times 0.052 \times h_m) \quad (3.6)$$

Solving Eqs. 3.5 and 3.6 simultaneously, one obtains h_g and h_m :

$$h_g = 5,141 \text{ ft}$$

$$h_m = 8,859 \text{ ft}$$

The length of the gas column from the intermediate casing seat, h_{gi} , is:

$$h_{gi} = 11,100 - 8,859 = 2,241 \text{ ft}$$

Burst pressure at the bottom of the drilling fluid column

$$= \text{internal pressure} - \text{external pressure}$$

$$\begin{aligned} \text{Internal pressure at 8,859 ft} &= 5,000 + 17.9 \times 0.052 \times 8,859 \\ &= 13,246 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{External pressure at 8859 ft} &= 0.465 \times 8,859 \\ &= 4,119 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{Burst pressure at 8,859 ft} &= 13,246 - 4,119 \\ &= 9,127 \text{ psi} \end{aligned}$$

$$\text{Burst pressure at casing seat} = \text{internal pressure} - \text{external pressure}$$

$$\begin{aligned} \text{Internal pressure at 11,100 ft} &= \text{pressure at 8,859 ft} + (G_{pg} \times h_{gi}) \\ &= 13,246 + 224.1 \\ &= 13,470 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{Burst pressure at 11,100 ft} &= 13,470 - 11,100 \times 0.45 \\ &= 8,475 \text{ psi} \end{aligned}$$

In Fig. 3.9 the burst pressure line is constructed between 5,000 psi at the surface, 9,127 psi at 8,859 ft and 8,475 psi at 11,100 ft. The burst resistances of the suitable grades from Table 3.2 are given in Table 3.12.

The grades that satisfy both burst and collapse requirements and the intervals for which they are valid are listed in Table 3.13.

Table 3.12: Burst resistances of grades suitable for intermediate casing.

Grade	Weight (lb/ft)	Coupling	Burst resistance (psi)	
			SF = 1	SF = 1.1
L-80	98	BTC	7,530	6,845
P-110	85	PTC	8,750	7,954
P-110	98	PTC	10,350	9,409

Table 3.13: Most economical intermediate casing based on collapse and burst loading.

Section	Depth (ft)	Grade and Weight (lb/ft)	Length (ft)
1	0 - 4,000	L-80, 98	4,000
2	4,000 - 6,400	P-110, 85	2,400
3	6,400 - 11,100	P-110, 98	4,700

Tension

The suitability of the selected grades for tension are checked by considering cumulative buoyant weight, buckling force, shock load and pressure testing and maximal dogleg of 3°/100 ft is considered when calculating the tension load due to bending. Hence, starting from the bottom, Table 3.14 is produced.

It is evident from Table 3.14 that grade L-80 (98 lb/ft) is not suitable for top section. Before changing the top section of the string the effect of pressure testing can be considered.

Pressure Testing and Shock Loading

Axial tension due to pressure testing:

$$\begin{aligned}
 &= \text{Grade L-80 burst pressure resistance} \times 0.6 \times A_s \\
 &= 7,530 \times 0.6 \times 28.56 \\
 &= 129,034 \text{ lbf}
 \end{aligned}$$

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$$\text{Top joint tension} = (4) + (6) + 129,034 = 1,240,007 \text{ lbf}$$

$$\begin{aligned} SF &= Y_p / \text{Total tension} \\ &= 2,286,000 / 1,240,007 \\ &= 1.84 \end{aligned}$$

Table 3.14: Total tensile loads on intermediate casing string.

(1) Depth interval (ft)	(2) Grade and Weight (lb/ft)	(3) Buoyant weight of section joint (1,000 lbf) $(1) \times W_n \times BF$ $BF = 0.817$	(4) Cumulative buoyant weight carried by the top joint (1,000 lbf)
11,100 - 6,400	P-110, 98	376.310	376.310
6,400 - 4,000	P-110, 85	166.668	542.978
4,000 - 0	L-80, 98	320.264	863.242

(5) Shock load carried by each joint (1,000 lbf) $(3, 200W_n)$	(6) Bending load in each section (1,000 lbf) $(63 d_o W_n \Theta)$	(7) Total tension (1,000 lbf) $(4) + (5) + (6)$	(8) $SF = \frac{Y_p}{\text{Total tension}}$
313.60	247.731	937.641	$2,800/937.64 = 2.98$
272.00	214.869	1,029.847	$2,290/1,029 = 2.22$
313.60	247.731	1,424.573	$2,286/1,424 = 1.61$

The pressure testing calculations indicate that the upper section is suitable. However, it is the worst case that one is designing for and in this case as Column (5) in Table 3.14 attests, it is the shock load.

Tension load is calculated by considering the cumulative buoyant weight at the top joint (4), shock load (5), and bending load (6). The length of Section 1, x , that satisfies the requirement for tensional load can be calculated as follows:

$$\begin{aligned} \text{Minimum safety factor } (= 1.8) &= \frac{Y_p}{\text{Total tension}} \\ \text{Total tension load} &= (98x + 2,400 \times 85 + 4,700 \times 98) \times 0.817 + 313,600 \\ &\quad + 24,7731 \\ &= 80.07x + 1,104,309.2 \text{ lbf} \end{aligned}$$

Hence,

$$1.8 = \frac{2,286,000}{80.07x + 1,104,309.2}$$

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$$x = \frac{298,243.44}{144.118} = 2,069 \text{ ft or 52 joints.}$$

Thus, the part of Section 1 to be replaced by a higher grade casing is (4,000 - 2,000) 2,000 ft or 50 joints. If this length is replaced by P-110 (98 lb/ft). The safety factor for tension will be:

$$SF = \frac{2,800,000}{1,424,573} = 1.97$$

Table 3.15: Intermediate casing selection based on collapse, burst and tensile loads.

Section	Depth (ft)	Grade and Weight (lb/ft)	Length (ft)
1	0 - 2,000	P-110, 98	2,000
2	2,000 - 4,000	L-80, 98	2,000
3	4,000 - 6,400	P-110, 85	2,400
4	6,400 - 11,100	P-110, 98	4,700

Biaxial Effect

The weakest grade among the four sections is P-110 (85 lb/ft). It is, therefore important to check for the collapse resistance of this grade under axial tension.

(1) Axial stress, σ_a , carried by P-110 (85 lb/ft) is:

$$\sigma_a = \frac{376,310}{24.39} = 15,431 \text{ psi.}$$

(2) Pipe yield stress:

$$\sigma_y = \frac{2,682,000}{24.39} = 109,981 \text{ psi.}$$

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(3) From Eq. 2.163, the effective yield stress is given by:

$$\begin{aligned}\sigma_e &= \sigma_y \left\{ \left[1 - 0.75 \left(\frac{\sigma_a}{\sigma_y} \right)^2 \right]^{0.5} - 0.5 \left(\frac{\sigma_a}{\sigma_y} \right) \right\} \\ &= 109,981 \left\{ \left[1 - 0.75 \left(\frac{15,431}{109,981} \right)^2 \right]^{0.5} - 0.5 \left(\frac{15,431}{109,981} \right) \right\} \\ &= 101,450 \text{ psi}\end{aligned}$$

(4) $d_o/t = 13.375/0.608 = 21.998$.

(5) The values of A to G are calculated using the equations in Table 2.1 and the value of σ_e above:

$$\begin{aligned}A &= 3.1483 \\ B &= 0.0776 \\ C &= 2,596.26 \\ F &= 2.0441 \\ G &= 0.0504\end{aligned}$$

(6) Collapse failure mode ranges are:

$$\begin{aligned}\frac{[(A-2)^2 + 8(B+C/\sigma_e)]^{0.5} + (A-2)}{2(B+C/\sigma_e)} &= 12.661 \\ \frac{\sigma_e(A-F)}{C + \sigma_e(B-G)} &= 20.913 \\ \frac{2+B/A}{3B/A} &= 27.389\end{aligned}$$

(7) Inasmuch as $d_o/t = 21.99$, the failure mode is in the elasto-plastic region.

(8) Hence, the reduced collapse resistance of P-110 (85 lb/ft) is 4,317 psi.

(9) Thus, the safety factor for collapse at 6,400 ft is:

$$\begin{aligned}SF_c &= \frac{\text{Reduced collapse resistance}}{\text{Collapse load at 6,400 ft}} \\ &= \frac{4,317}{4,023} = 1.07\end{aligned}$$

which satisfies the design criterion $SF_c \geq 0.85$

Planning & Design of Casing

Table 3.16: Total tensile loads on revised intermediate casing string.

(1) Depth interval (ft)	(2) Grade and Weight (lb/ft)	(3) Buoyant weight of section joint (1,000 lbf) $(1) \times W_n \times BF (= 0.817)$	(4) Cumulative buoyant weight carried by the top joint (1,000 lbf)
11,100 - 6,400	P-110, 98	376.310	376.310
6,400 - 4,000	P-110, 85	166.668	542.978
4,000 - 2,000	L-80, 98	160.132	703.110
2,000 - 0	P-110, 98	160.132	863.242

(5) Shock load carried by each joint (1000 lbf) $(3,200W_n)$	(6) Bending load in each section (1,000 lbf) $(63 d_o W_n \Theta)$	(7) Total tension (1,000 lbf) $(4) + (5) + (6)$	(8) $SF = \frac{Y_r}{\text{Total tension}}$
313.60	247.731	937.641	$2,800/937.64 = 2.98$
272.00	214.869	1,029.847	$2,290/1,029 = 2.22$
313.60	247.731	1,264.441	$2,286/1,264.44 = 1.81$
313.60	247.731	1,424.573	$2,800/1,424.57 = 1.97$

3.3.3 Drilling Liner (9-in. pipe)

Drilling liner is set between 10,500 ft and 14,000 ft with an overlap of 600 ft between 13 in casing and 9 in liner. The liner is cemented from the bottom to the top. Design loads for collapse and burst are calculated using the same assumptions as for the intermediate casing (refer to Fig. 3.8). The effect of biaxial load on collapse and design requirement for buckling are ignored.

Collapse

$$\text{Collapse pressure at 10,500 ft} = \text{external pressure} - \text{internal pressure}$$

$$\begin{aligned} \text{External pressure at 10,500 ft} &= Gp_m \times 10,500 \text{ ft} \\ &= 12 \times 0.052 \times 10,500 = 6,552 \text{ ft} \end{aligned}$$

$$\begin{aligned} \text{Internal pressure at 10,500 ft} &= Gp_m \times \text{fluid column height (Fig. 3.8)} \\ &= 17.9 \times 0.052 \times (10,500 - 7,006) \\ &= 3,252 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{Collapse pressure at 10,500 ft} &= 6,552 - 3,252 \\ &= 3,300 \text{ psi} \end{aligned}$$

$$\text{Collapse pressure at 14,000 ft} = \text{external pressure} - \text{internal pressure}$$

$$\begin{aligned} \text{External pressure at 14,000 ft} &= 12 \times 0.052 \times 14,000 \\ &= 8,736 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{Internal pressure at 14,000 ft} &= 17.9 \times 0.052 \times 6,994 \\ &= 6,510 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{Collapse pressure at 14,000 ft} &= 8,736 - 6,510 \\ &= 2,226 \text{ psi} \end{aligned}$$

Table 3.22: Collapse resistance of grades suitable for drilling liner.

Grade	Weight (lb/ft)	Coupling	Collapse resistance (psi)	
			SF = 1	SF = 0.85
P-110	47	LTC	5,310	6,247
L-80	58.4	LTC	7,890	9,282

Planning & Design of Casing

In Fig. 3.12 the collapse line is constructed between 3,300 psi at 10,500 ft and 2,226 psi at 14,000 ft. The collapse resistances of suitable steel grades from Table 3.3 are given in Table 3.22. Notice that both P-110 (47 lb/ft) and L-80 (58.4 lb/ft) grades satisfy the requirement for collapse load design.

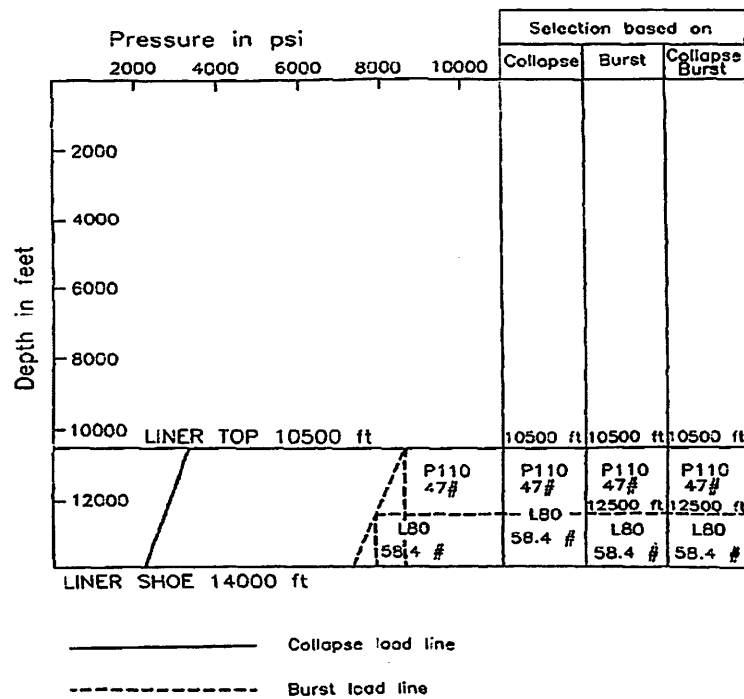


Fig. 3.12: Selection of casing grades and weight based on the collapse and burst loads for liner.

Burst

Burst pressure at 10,500 ft (Fig. 3.8)

$$= \text{internal pressure} - \text{external pressure}$$

$$\begin{aligned} \text{Internal pressure at 10,500 ft} &= \text{surface pressure} + \text{hydrostatic} \\ &\quad \text{pressure of drilling fluid column} \\ &\quad + \text{hydrostatic pressure of the gas column} \end{aligned}$$

$$\begin{aligned} &= 5,000 + 8,901.6 \times 17.9 \times 0.052 \\ &\quad + (10,500 - 8,901.6) \times 0.1 \\ &= 13,445 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{External pressure at 10,500 ft} &= \text{hydrostatic head of the salt water column} \\ &= 0.465 \times 10,500 \\ &= 4,882.5 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{Burst pressure at 10,500 ft} &= 13,445.44 - 4,882.5 \\ &= 8,563 \text{ psi} \end{aligned}$$

$$\begin{aligned} \text{Burst pressure at 14,000 ft} &= \text{injection pressure at 14,000 ft} \\ &\quad - \text{saturated salt water column} \\ &= 13,788.32 - 0.465 \times 14,000 \\ &= 7,278 \text{ psi} \end{aligned}$$

In Fig. 3.12, the burst pressure line is constructed between 8,563 psi at 10,500 ft and 7,278 psi at 14,000 ft. The burst resistances of the suitable grades from Table 3.3 are shown in Table 3.23. The burst resistances of these grades are also plotted in Fig. 3-12 as vertical lines and those grades that satisfy both burst and collapse design requirements are given in Table 3.24.

Table 3.23: Burst resistances of grades suitable for drilling liner.

Grade	Weight (lb/ft)	Coupling	Burst resistance (psi)	
			SF = 1	SF = 1.1
L-80	54.4	LTC	8,650	7,864
P-110	47	LTC	9,440	8,581

Tension

Suitability of the selected grade for tension is checked by considering cumulative buoyant weight, shock load, and pressure testing. The results are summarized in Table 3.25.

Table 3.24: Most economical drilling liner based on collapse and burst loads.

Section	Depth (ft)	Grade and Weight (lb/ft)	Length (ft)
1	10,500 – 12,500	P-110, 47	2,000
2	12,500 – 14,000	L-80, 58	1,500

Table 3.25: Total tensile loads on drilling liner.

(1) Depth (ft)	(2) Grade and Weight (lb/ft)	(3) Buoyant weight of section joint (1,000 lbf) $(1) \times W_n \times BF$ $BF = 0.743$	(4) Cumulative buoyant weight carried by the top joint (1,000 lbf)
14,000 – 12,500	L-80, 58.4	65.105	65.105
12,500 – 10,500	P-110, 47	69.861	134.966

(5) Shock load carried by each section (1,000 lbf) $(3,200 W_n)$	(6) Total tension (1,000 lbf) $(4) + (5)$	(7) $SF = \frac{Y_p}{\text{Total tension}}$
186.88	251.985	$1,151/251.985 = 4.57$
150.40	285.366	$1,213/285.366 = 4.25$

Final Selection

From Table 3.25 it follows that L-80 (58.4 lb/ft) and P-110 (47 lb/ft) satisfy the requirement for tension due to buoyant weight and shock load. Inasmuch as the safety factor is double the required margin, it is not necessary to check for pressure testing.

3.3.4 Production Casing (7-in, pipe)

Production casing is set to a depth of 19,000 ft and partially cemented at the casing seat. The design load calculations for collapse and burst are presented in Fig. 3.13.

Collapse

The collapse design is based on the premise that the well is in its last phase production and the reservoir has been depleted to a very low abandonment pressure (Bourgoyne et al., 1985). During this phase of production, any leak in the tubing may lead to a partial or complete loss of packer fluid from the annulus between the tubing and the casing. Thus, for the purpose of collapse design the following assumptions are made:

1. Casing is considered empty.
2. Fluid specific weight outside the pipe is the specific weight of the drilling fluid inside the well when the pipe was run.
3. Beneficial effect of cement is ignored.

Based on the above assumptions, the design load for collapse can be calculated as follows:

Collapse pressure at surface = 0 psi

$$\begin{aligned}
 \text{Collapse pressure at casing seat} &= \text{external pressure} - \text{internal pressure} \\
 &= 17.9 \times 0.052 \times 14,000 - 0 \\
 &= 13,031 \text{ psi}
 \end{aligned}$$

Table 3.26: Collapse resistance of grades suitable for production casing.

Grade	Weight (lb/ft)	Coupling	Collapse resistance (psi)	
			$SF = 1$	$SF = 0.85$
V-150	38	PTC	19,240	22,635
V-150	41	PTC	22,810	26,835
V-150	46	PTC	25,970	30,552
SOO-155	46	PTC	26,830	31,564

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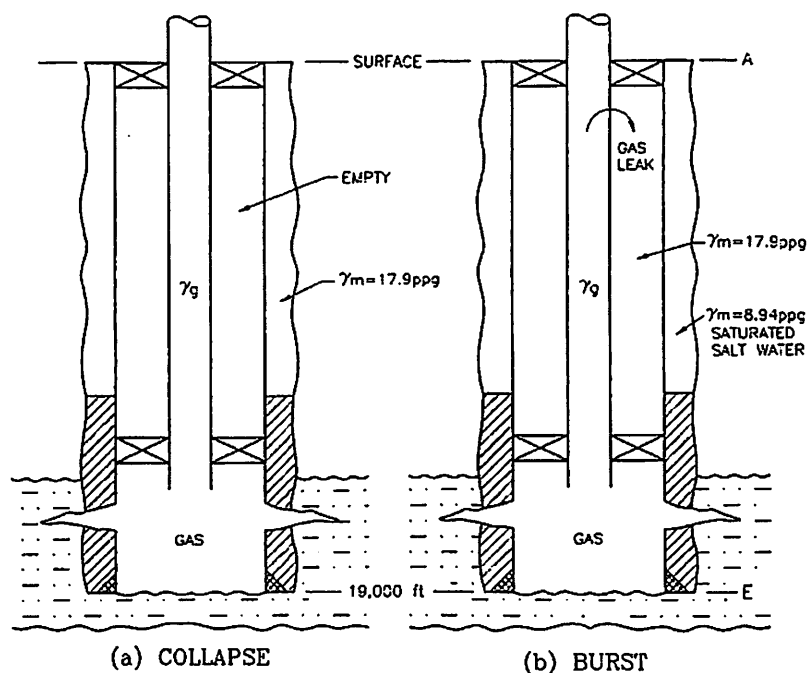


Fig. 3.13: Collapse and burst loads on the production casing.

In Fig. 3.13, the collapse line is constructed between 0 psi at the surface and 13,031 psi at 19,000 ft. Collapse resistance of the suitable grades from Table 3.3 are presented in Table 3.26 and all these grades satisfy the requirement for maximum collapse design load.

Burst

In most cases, production of hydrocarbons is via tubing sealed by a packer, as shown in Fig. 3.13. Under ideal conditions, only the casing section above the shoe will be subjected to burst pressure. The production casing, however, must be able to withstand the burst pressure if the production tubing fails. Thus, the design load for burst should be based on the worst possible scenario.

For the Purpose of the design of burst load the following assumptions are made:

1. Producing well has a bottom hole pressure equal to formation pore pressure and the Producing fluid is gas.
2. Production tubing leaks gas.
3. Specific weight of the fluid inside the annulus between the tubing and casing is that of The drilling fluid inside the well when the pipe was run.
4. Specific weight of the fluid outside the casing is that of the deteriorated drilling fluid, i.e. The specific weight of saturated salt water.

Planning & Design of Casing

Based on the above assumptions, the design for burst load proceeds as follows:

$$\begin{aligned}
 \text{Burst load at surface} &= \text{internal pressure} - \text{external pressure} \\
 \text{Internal pressure at surface} &= \text{shut-in bottomhole pressure} \\
 &\quad - \text{hydrostatic head of the gas column} \\
 &= 17.45 \times 0.052 \times 19,000 - 0.1 \times 19,000 \\
 &= 15,340.6 \text{ psi} \\
 \text{Burst pressure at surface} &= 15,340.6 - 0 \\
 &= 15,340.6 \text{ psi} \\
 \text{Burst pressure at casing shoe} &= \text{internal pressure} - \text{external pressure} \\
 \text{Internal pressure at casing shoe} &= \text{hydrostatic pressure of the fluid column} \\
 &\quad + \text{surface pressure due to gas leak at top of tubing} \\
 &= 17.9 \times 0.052 \times 19,000 + 15,340.6 \\
 &= 33,025.8 \text{ psi} \\
 \text{External pressure at shoe} &= 0.465 \times 19,000 \\
 &= 8,835 \text{ psi} \\
 \text{Burst pressure at casing shoe} &= 33,025.8 - 8,835 \\
 &= 24,190.8 \text{ psi}
 \end{aligned}$$

In Fig. 3.13, the burst line is drawn between 15,350.6 psi at the surface and 24,190.8 psi at 19,000 ft. The burst resistances of the suitable grades from Table 3.3 are shown in Table 3.27 and are plotted as vertical lines in Fig 3.14.

Table 3.27: Burst resistance of grades suitable for production casing.

Grade	Weight (lb/ft)	Coupling	Burst resistance (psi)	
			$SF = 1$	$SF = 1.1$
V-150	38	PTC	18,900	17,182
MW-155	38	Extreme-line	20,930	19,028
V-150	46	PTC	25,070	22,790
SOO-155	46	PTC	25,910	23,550

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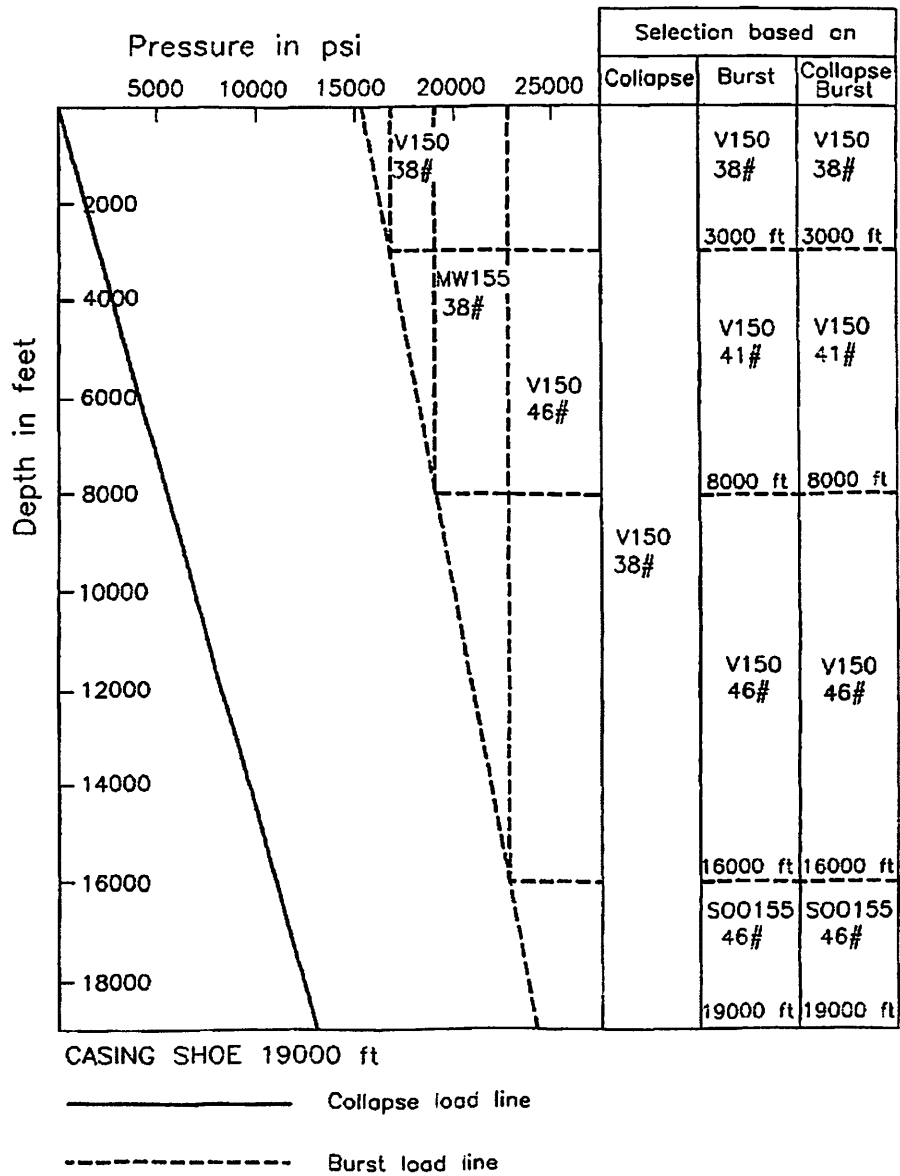


Fig. 3.14: Selection of casing grades and weights based on the collapse and burst loads for the production casing.

Selection based on collapse and burst

From Fig. 3.14, it is evident that grade SOO-155 which has the highest burst resistance properties satisfies the design requirement up to 17,200 ft. It also satisfy the design requirement up to 16000 ft if the safety factor is ignored. Thus grade SOO-155 can be safely used only if it satisfies the other design requirements. The top of cement must also reach a depth of 17,200 ft to provide additional strength to this pipe section. Hence, the selection based on collapse and burst is shown in Table 3.28.

Table 3.28: Most economical production casing based on collapse and burst loads.

Section	Depth (ft)	Grade and Weight (lb/ft)	Coupling	Length (ft)
1	0 - 3,000	V-150, 38	PTC	3,000
2	3,000 - 8,000	MW-155, 38	Extreme line	5,000
3	8,000 - 16,000	V-150, 46	PTC	8,000
4	16,000 - 19,000	SOO-155, 46	PTC	3,000

Tension

The suitability of the selected grades under tension is checked by considering cumulative buoyant weight, shock load, and pressure testing. Thus starting from the bottom, Table 3.29 is produced which shows that all the section the requirement for tensional load based on buoyant weight and shock load.

Pressure Testing

Grade V-150 (38 lb/ft) has the lowest safety factor and should, then be checked for pressure testing. Tensional load carried by this section during pressure testing is equal to:

$$\begin{aligned}
 F_t &= 18,900 \times 0.6 \times A_s (A_s = 10.95) \\
 &= 124,173 \text{ lbf}
 \end{aligned}$$

Planning & Design of Casing

Total tension load carried by V-150 (38 lb/ft)

$$\begin{aligned}
 &= \text{buoyant weight carried by the top joint} \\
 &= + \text{tensional load due to the pressure testing} \\
 &= 588,430 + 124,173 \\
 &= 712,603 \text{ lbf}
 \end{aligned}$$

$$SF = \left(\frac{Y_p}{\text{Total load}} \right) = \frac{1,430,000}{712,603} = 2.01$$

Inasmuch as this value is greater than the design safety factor of 1.8. Grade V-150 (38 lb/ft) satisfies tensional load requirements.

Table 3.29: Total tensile loads on production casing.

(1) Depth (ft)	(2) Grade and Weight (lb/ft)	(3) Buoyant weight of each section joint (1,000 lbf) $(1) \times W_n \times BF$ $BF = 0.726$	(4) Cumulative buoyant weight carried by the top joint (1,000 lbf)
19,000 - 16,000	SOO-155, 46	100.25	100.25
16,000 - 8,000	V-150, 46	267.34	367.59
8,000 - 3,000	MW-155, 38	138.03	505.62
3,000 - 0	V-150, 38	82.82	588.43

(5) Shock load carried by each joint (1,000 lbf) $3,200 \times W_n$	(6) Total load carried by the top joint (1,000 lbf)	(7) $SF = \frac{Y_p}{\text{Total load}}$
147.20	247.51	$1,344/247.51 = 5.43$
147.20	514.79	$1,344/514.79 = 2.61$
121.60	627.21	$1,592/627.21 = 2.56$
121.60	710.03	$1,430/710.03 = 2.01$

Biaxial Effect

Axial tension reduces the collapse resistance and is most critical at the joint of the weakest grade. All the grades selected for production casing have significantly higher collapse resistance than required. Casing sections from the intermediate position. however, can be checked for reduced collapse resistance (V-150, 46 lb/ft) at 8,000 ft.

As illustrated previously, the modified collapse resistance of grade V-150 (46 lb/ft) under an axial load of 367,356 lbf can be calculated to be 23,250 psi. Hence,

$$\begin{aligned}
 SF \text{ for collapse} &= \frac{\text{Reduced collapse resistance}}{\text{Collapse pressure at 8,000 ft}} \\
 &= \frac{23,250}{5,600} \\
 &= 4.15
 \end{aligned}$$

Table 3.30: Final casing selection for production casing string.

Depth (ft)	Grade and Weight (lb/ft)	Coupling
0 – 3,000	V-150, 38	PTC
3,000 – 8,000	MW-155, 38	Extreme-line
8,000 – 16,000	V-150, 46	PTC
16,000 – 19,000	SOO-155, 46	PTC

3.3.5 Conductor Pipe (26-in, pipe)

Conductor pipe is set to a depth of 350 ft and cemented back to the surface. In addition to the principal loads of collapse, burst and tension, it is also subjected to a compression load, because it carries the weight of the other pipes. Thus, the conductor pipe must be checked for compression load as well.

Collapse

In the design of collapse load, the following assumptions are made (refer to Fig.3.15):

1. Complete loss of fluid inside the pipe.
2. Specific weight of the fluid outside the pipe is that of the drilling fluid in the well when The pipe was run.

$$\text{Collapse pressure at the surface} = 0$$

$$\begin{aligned} \text{Collapse pressure at the casing shoe} &= 9.5 \times 0.052 \times 320 - 0 \\ &= 158 \text{ psi} \end{aligned}$$

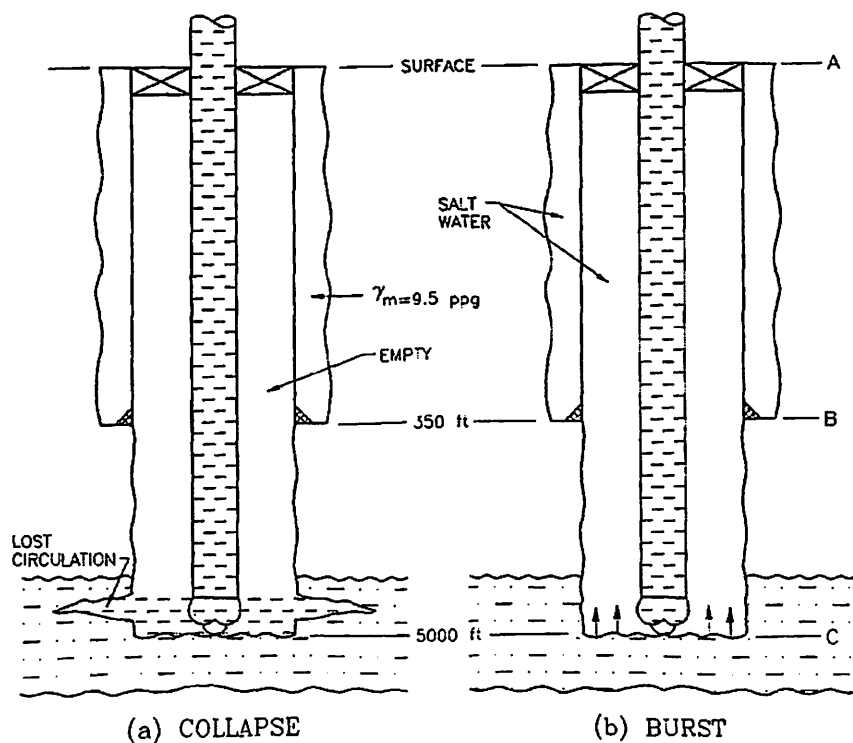


Fig. 3.15: Collapse and burst loads on conductor.

Burst

In calculating the burst load, it is assumed that no gas exists at shallow depths and a saturated salt water kick is encountered in drilling the next interval. Hence in calculating the burst pressure, the following assumptions are made (refer to Fig. 3.13):

1. Casing is filled with saturated salt water.
2. Saturated salt water is present outside the casing.

$$\text{Burst pressure at casing shoe} = \text{internal pressure} - \text{external pressure}$$

$$\begin{aligned}\text{Internal pressure at casing shoe} &= \text{formation pressure at 5,000 ft} \\ &\quad - \text{hydrostatic pressure due to the salt} \\ &\quad \text{water between 350 and 5,000 ft} \\ &= 0.465 \times 5,000 - [(5,000 - 350) \times 0.465] \\ &= 162.75 \text{ psi}\end{aligned}$$

$$\begin{aligned}\text{Burst pressure at casing shoe} &= 162.75 - 0.465 \times 350 \\ &= 0 \text{ psi}\end{aligned}$$

$$\begin{aligned}\text{Burst pressure at surface} &= \text{formation pressure at 5,000 ft} \\ &\quad - \text{hydrostatic pressure at the} \\ &\quad \text{fluid column} - \text{external pressure} \\ &= 5,000 (0.465 - 0.465) - 0 \\ &= 0 \text{ psi}\end{aligned}$$

Selection based on collapse and burst

As shown in Table 3.3 both available grades have collapse and burst resistance values well in excess of those calculated above. Conductor pipe will, however, be subjected to a compression load resulting from the weight of casing-head housing and subsequent casing strings. Taking this factor into consideration, grade K-55 (133 lb/ft) with regular buttress coupling can be selected.

Compression

In checking for compression load, it is assumed that the tensile strength is equal to the compressive strength of casing. A safety factor of greater than 1.1 is desired.

Planning & Design of Casing

Compressive load carried by the conductor pipe is equal to the total buoyant weight, W_{bu} , of the subsequent casing strings.

$$\begin{aligned}\text{Compressive load} &= W_{bu} \text{ of surface pipe} \\ &\quad + W_{bu} \text{ of intermediate pipe} + W_{bu} \text{ of liner} \\ &\quad + W_{bu} \text{ of production pipe} \\ &= 390,093 + 863,242 + 134,928 + 588,430 \\ &= 1,976,990 \text{ lbf}\end{aligned}$$

$$\begin{aligned}\text{Safety Factor, } SF &= \frac{Y_p \text{ of K-55 (133 lb/ft)}}{\text{Total buoyant weight}} \\ &= \frac{2,125,000}{1,976,990} = 1.08\end{aligned}$$

This suggests that the steel grade K-55, 133 satisfy the requirement for compression load.

Final Selection

The final selection is summarized in Table 3.30.

Table 3.30: Final casing selection for production casing string.

Depth (ft)	Grade and Weight (lb/ft)	Coupling
0 – 3,000	V-150, 38	PTC
3,000 – 8,000	MW-155, 38	Extreme-line
8,000 – 16,000	V-150, 46	PTC
16,000 – 19,000	SOO-155, 46	PTC

4.0 WELLHEAD SELECTION

Having completed the casing design, we have all the information required to allow us to select a wellhead. The wellhead must be of the correct pressure rating, designed for the desired service like H_2S and be capable of accommodating all designed and contingent casing strings,

Having selected a wellhead, its specification should be included in the Drilling Program along with a sectional view of its component stack up.

Well Head Assembly

Well head equipments are attached to the top of the tubular equipments used in a well – to support the tubular string, hang them, provide seals between string and control production from the well. These equipments are covered in American petroleum institute (API) specification- 6A.

Lower most Casing Head

Lower most casing head is the unit or housing attached to the end of the surface pipe to provide a means for supporting the other strings of pipe, and sealing the annular space between the two strings of casing.

It is composed of casing hanger bowl to receive the casing hanger for attaching blow-out preventers (BOPs) or other intermediate casing heads or tubing heads. The lower connection consists of a female or male head or a slip-on socket for welding.

Lowermost casing hanger

It seats in a bowl of a lowermost casing head or an intermediate casing head to suspend the next smaller casing securely and provide a seal between the suspended casing and the casing bowl.

It usually consists of a set of slips and a sealing mechanism. It is latched around the casing and dropped through the BOPs to the casing bowl.

Intermediate casing heads

An intermediate casing head is spool type unit or housing attached to the top flange of the underlying casing head, to provide a means of supporting the next smaller casing string and sealing the annular space between the two casing strings.

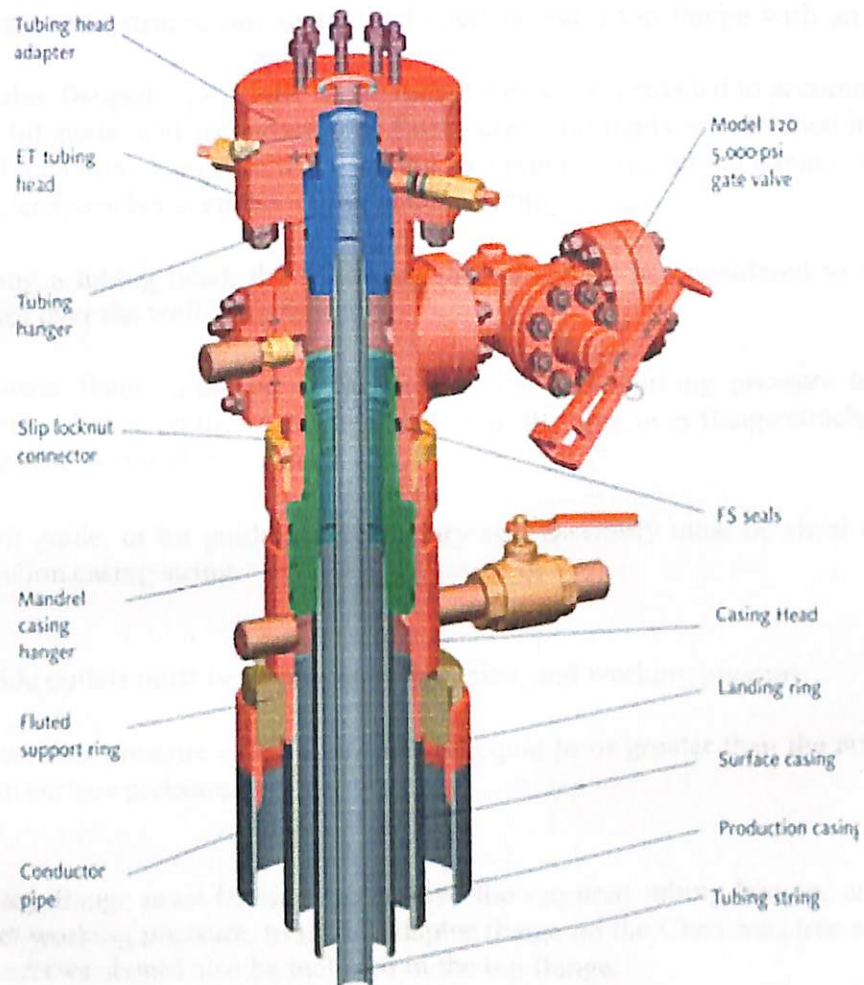
It is composed of:

- 1) A lower flange (counter-bored with a recess to accommodate a removable bit guide, or a bit guide and secondary seal assembly)
- 2) One or two side outlets
- 3) A top flange with an internal casing hanger bowl.

Intermediate casing hangers

These are identical in every respect to casing hangers used in lowermost casing heads and are used to suspend the next smaller casing in the intermediate casing head.

Planning & Design of Casing



Well Head assembly

Tubing head

It is a spool-type unit or housing attached to the top flange of the uppermost casing head to provide a support for the tubing string and to seal annular space between the tubing string and production casing string.

It also provides access to the casing tubing annulus through side outlets (threaded stud or extended flange).

It is composed of a lower flange (or could have threaded button which screws directly on the production casing string), one or two side outlets and a top flange with an internal hanger bowl.

On the double-flanged type, in the lower flange a recess is provided to accommodate a bit guide or a bit guide and secondary seal. Lock screws normally are included in the top flange to hold the tubing hanger in place and/or to compress the tubing hanger seal, with seals the annular space between the tubing and the casing.

In selecting a tubing head, the following factors should be considered to maintain positive control over the well at all times:

- 1) The lower flange must be of the proper size and working pressure to fit the uppermost flange on the casing head below or the crossover flange attached to the casing head flange if one is used.
- 2) The bit guide, or bit guide and secondary seal assembly must be sized to fit the production casing string.
- 3) The side outlets must be of proper design, size, and working pressure
- 4) The working pressure of the unit must be equal to or greater than the anticipated shut-in surface pressure.
- 5) The top flange must be sized to receive the required tubing hanger, and of the correct working pressure, to fit the adapter flange on the Christmas tree assembly. Lock screws should also be included in the top flange.

The tubing head should be full opening to provide full size access to the production casing string below and be adaptable to future remedial operations as well as to Artificial lift.

Tubing hanger

It is used to provide a seal between tubing and the tubing head, or to support the tubing and to seal between the tubing and the tubing head.

Several types of tubing hangers are available and each has a particular application. More commonly used types are wrap-around, polished-joint, ball-weevil and stripper rubber.

The most popular is wrap-around type. It is composed of two hinged halves, which include a resilient sealing element between two steel mandrels or plates. The hanger can be latched around the tubing, dropped into the tubing-head bowl, and secured in place by the tubing-head lock screws.

The lock screws force the top steel mandrel or plate down to compress the sealing element and form a seal between the tubing and tubing head.

Full tubing weight can be temporarily supported on the tubing hanger, but permanent support is provided by threading the top tubing thread into the adapter flange on top of the tubing head. The hanger then acts as a seal only.

In selecting a tubing hanger, it should be ensured that the hanger will provide an adequate seal between the tubing and the tubing head for the particular well conditions (metal to metal seals are desired in most cases), and that it is of standard size, suitable for lowering through full opening drilling equipment.

Adapter

It is used to connect two flanges of different dimensions or connect a flange to a threaded end.

Crossover flange

A crossover flange is an intermediate flange used to connect flanges of different working pressures. These are usually available in two types:

A double studded crossover flange is studded and grooved on one side for one working pressure, and studded and grooved on the other side for the next higher working pressure rating. The flange must also include a seal around the inner string of pipe to prevent pressure from the higher-working pressure side reaching the lower-working pressure side. The seal may be of resilient type, plastic packed type or welded type.

Another type of cross-over flange includes a restricted-ring groove in the top side of the flange to fit a corresponding restricted ring groove in the mating head. The restricted-ring groove and the seal between the flange and the inner casing string act to restrict the pressure to a smaller area, thereby allowing a higher pressure rating.

Christmas tree assembly

A Christmas tree is an assembly of valves and fittings used to control production and provide access to the producing tubing string. It includes all equipment above the tubing-head top flange. A typical Christmas tree is shown in fig 20.10

Planning & Design of Casing

Many variations in arrangement of well head and Christmas Tree Assemblies are available to satisfy the needs of any particular application.

Full-opening valves must be used in the vertical run of the Christmas tree assembly to provide access to the tubing.

Restricted-opening valves are sometimes used as wing valves, without loss of efficiency or utility, to affect an economic saving.

Valves could be flanged or threaded type or mono-block forged. Flanged valves are preferred on applications of 210 kg/cm^2 (3,000 psia) working pressure and above. Flanged valves are available in sizes from $1\frac{3}{16}$ " through $7\frac{1}{16}$ " with working pressure rating from 140 to $1,410 \text{ kg/cm}^2$ (2000 to 20,000 psi).

3.4 REFERENCES

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APPENDIX – A

Table : D/t range for Elastic collapse

1	2
GRADE	D/t Range
H – 40	42.70 and greater
-50*	38.83 -
J-K-55&D	37.20 -
-60*	35.73 -
-70*	33.17 -
C-75&E	32.05 -
L-80 &N-80	31.05 -
-90*	29.18 -
C-95	28.25 -
-100*	27.60 -
P-105	26.88 -
P-110	26.20 -
-120*	25.01 -
-125	24.53 -
-130*	23.94 -
-135	23.42 -
-140	23.00 -
-150	22.12 -
-155	21.70 -
-160*	21.32 -
-170	20.59 -
-180	19.93 -

Table : D/t range for Elastic collapse

1	2	3	4	5
GRADE	FORMULA FACTOR			D/t range
	A	B	C	
H – 40	2.950	0.0463	755	16.44-26.62
-50*	2.976	0.0515	1056	15.24-25.63
J-K-55&D	2.990	0.0541	1205	14.80-24.99
-60*	3.005	0.0566	1356	14.44-24.42
-70*	3.037	0.0617	1656	13.85-23.38
C-75&E	3.060	0.0642	1805	13.67-23.09
L-80 &N-80	3.070	0.0667	1955	13.38-22.46
-90*	3.106	0.0718	2254	13.01-21.69
C-95	3.125	0.0745	2405	12.83-21.21
-100*	3.143	0.0768	2553	12.70-21.00
P-105	3.162	0.0795	2700	12.56-20.66
P-110	3.180	0.0820	2855	12.42-20.29
-120*	3.219	0.0870	3151	12.21-19.88
-125	3.240	0.0895	3300	12.12-19.65
-130*	3.258	0.0920	3451	12.02-19.40
-135	3.280	0.0945	3600	11.90-19.14
-140	3.295	0.0970	3750	11.83-18.95
-150	3.335	0.1020	4055	11.67-18.57
-155	3.356	0.1047	4204	11.59-18.37
-160*	3.375	0.1072	4356	11.52-18.19
-170	3.413	0.1123	4660	11.37-18.45
-180	3.449	0.1173	4966	11.23-17.47

Planning & Design of Casing

1	2	3	4
GRADE	FORMULA FACTORS		D/t Range
	F	G	
H - 40	2.047	0.03125	25.62-42.70
-50*	2.003	0.0347	25.63-38.83
J-K-55&D	1.990	0.0360	24.99-37.20
-60*	1.983	0.0373	24.42-35.73
-70*	1.984	0.0403	23.38-33.17
C-75&E	1.985	0.0417	23.09-32.05
L-80 &N-80	1.998	0.0434	22.46-31.05
-90*	2.017	0.0466	21.69-29.18
C-95	2.047	0.0490	21.21-28.25
-100*	2.040	0.0499	21.00-27.60
P-105	2.052	0.0515	20.66-26.88
P-110	2.075	0.0535	20.29-26.20
-120*	2.092	0.0565	19.88-25.01
-125	2.102	0.0580	19.65-24.53
-130*	2.119	0.0599	19.40-23.94
-135	2.129	0.0613	19.14-23.42
-140	2.142	0.0630	18.95-23.00
-150	2.170	0.0663	18.57-22.12
-155	2.188	0.06825	18.37-21.70
-160*	2.202	0.0700	18.19-21.32
-170	2.123	0.0698	18.45-20.59
-180	2.261	0.0769	17.47-19.93

Table:
D/t
range for
Elastic
collapse