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DEEP WELL TUBULAR DESIGN CONSIDERATIONS

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ABSTRACT

The tubular program of the ultra-deep well represents a major portion of the initial well costs, relates directly to probability of economically reaching projected depths and plays a continuous role in determining profitability during the well's productive life.

This paper reviews, in general terms, tubular safety factor considerations, compatibility of tubular material and end finish with well environments, and hole and pipe size combinations.

INTRODUCTION

The ultra-deep well is defined as one which is 18,000 to 28,000 feet deep. Drilling and completion technology for each well varies according to projected depth and anticipated downhole environment, such as high pressures, sour gas, clearance problems, etc. A particular set of conditions dictates tubular design considerations, and similar conditions found in like wells of various fields and basins; therefore, there can be a design relationship between ultradeep wells of two different fields (Buffalo Wallow and Washita) or two different basins (Delaware and Anadarko). For this reason, a general review of leading tubular designs for areas of ultra-deep drilling should be informative.

TUBULAR DESIGN SAFETY FACTOR CONSIDERATIONS

Without exception, all tubular designers consider Internal Yield, Collapse and Tension, and apply to each an adequate factor of safety over the anticipated loads. Most companies have established the minimum safety factors they wish to use as design criteria, but these factors must often be altered, due to well conditions, available tubulars, bit sizes, etc. Once projected depths and anticipated formation pressures have been established, pipe sizes and setting depths can be determined and the safety factors for Internal Yield, Collapse and Tension assigned.

Internal Yield

The loading for Internal Yield should be considered first (Ref. #1), since this factor will dictate the minimum weight and grade of pipe useable in a casing or tubing design. This Internal Yield safety factor, ofttimes referred to as "burst," should be applied to the test pressure rating (alternative test pressure, if listed), rather than the Internal Yield pressure. Examples:

7" 29#N-80

Internal Yield	Test Pressure
8,160 psi	7,500 psi

7"35#P-110

Internal Yield	Test Pressure	Alternative Test Pressure
13,690 psi	10,000 psi	12,500 psi

Past experience and recent analysis show that standard O.D. couplings, in the same grade as the casing, should not be pressure-rated equal to the pipe body, particularly in thick-wall casing. This is documented in API Bulletin 5C2, 13th Edition, dated April, 1970, wherein, of the 26 API 7" casing items listed in all weights and grades, excluding H-40, eight with Round Thread Couplings, 12 with regular O.D. Buttress Threaded Couplings and 25 with Special Clearance Buttress Couplings show Internal Yield pressure ratings lower than the pipe body.

The formula used for calculating these values is:

$$\frac{2 \times Ym \times t}{D}$$

Ym = Material Yield Value
t = Coupling Thickness*
D = Coupling Diameter

*Diameter at root of coupling thread at end of pin in the power-tight position.

7" 29#N-80 Buttress $\frac{2 \times 80m \times .405"}{7.656"} = \underline{8{,}460\#}$ $\underline{\underline{\text{Pipe } 8.160\#}}$

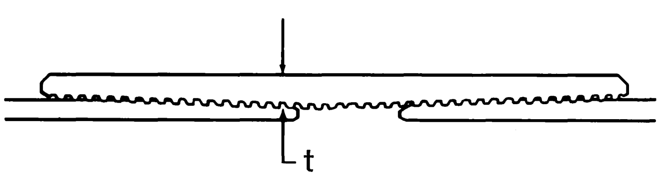


FIG. 1 — Coupling Internal Yield Calculation - Standard

Field running practices indicate that T&C thread interference is not consistent for a given torque value; that is, one joint will make up further than the next. Because of this, one major operator uses the pitch diameter to calculate Internal Yield:

7" 29#N-80 Buttress $\frac{2 \times 80m \times .351"}{7.656"} = \underline{7{,}340\#}$ $\underline{\underline{\text{Pipe } 8{,}160\#}}$

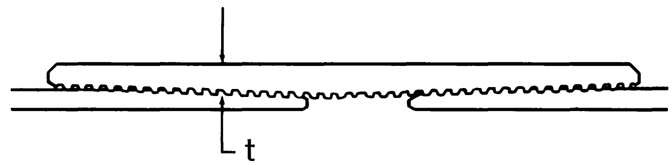


FIG. 2 — Coupling Internal Yield Calculation - Optional

A review of "Recent Developments in Casing Standards and Design," by John Wais, Jr., (Ref. #2) discloses another factor that should be considered when attempting to pressure-rate a coupling:

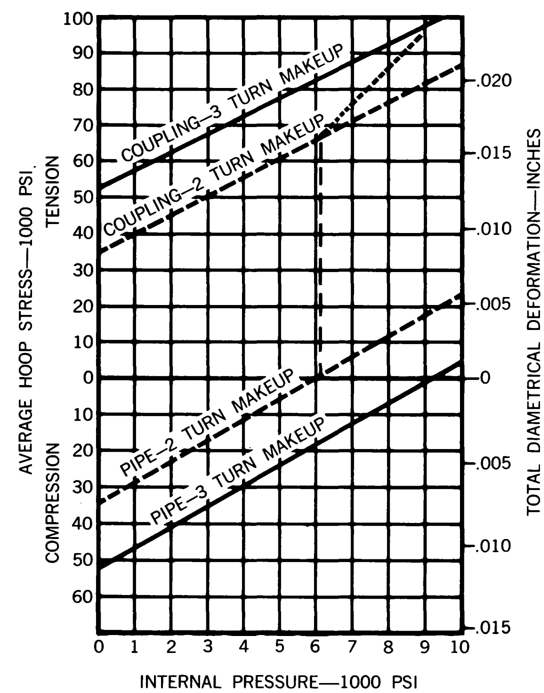


FIG. 3 — Effect of Makeup and Internal Pressure on Pipe and Coupling

Three turns of makeup, combined with 6,000 psi of internal pressure, will produce a hoop tension value (hoop stress) in the coupling exceeding the yield of N-80 material. This 6,000 psi is less than the test value of 7,500 psi, or the Internal Yield of 8,160 psi for 7" 29#N-80 casing.

Collapse

Formations with abnormally high pressures are encountered in both the Delaware and Anadarko Basins and have presented tubular design problems with respect to maintaining desirable Collapse safety factors. In addition to the high pressures of these formations, their location between formations of normal pressures requires the setting of additional liners. This compounds the difficulty of reaching prescribed T.D. with a reasonable hole size.

Liner sizes most commonly used through these formations are 7", 7 5/8" and 8 5/8". One well, currently being drilled in the Anadarko Basin, is designed for a 9 5/8" O.D. drilling liner from 14,000 to 22,000 feet in 16 ppg mud. To maintain a safety factor of 1.0, to avoid the use of ultra-high-strength material, and to maintain desirable bit sizes, over-size, heavy-wall, intermediate-grade casings, such as 7 3/4" and 8 3/4", have been developed.

Most operators are concerned with drilling wear on their liners and the related reduction of collapse resistance. One major oil company in the Delaware Basin lost a 22,000-foot well after several months of production because the 7 5/8" drilling liner and the tubing adjacent to a high-pressure formation collapsed. Well salvage proved economically unfeasible. Present methods of measuring and controlling this wear leave much to be desired. A design approach that has met with 100% success, to date, is to tie the production liner, rather than the drilling liner, back to the surface. The tieback is designed to withstand collapse forces of the intermediate high-pressure formations.

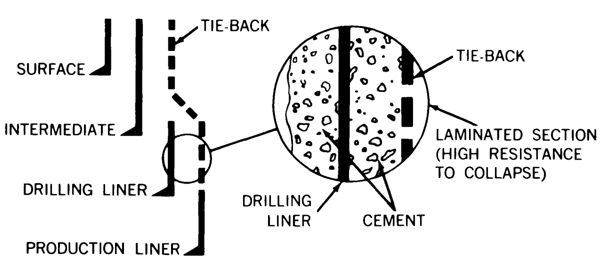


FIG. 4 — Laminated Section Adjacent to Geo Pressured Formation

Another notable problem in high-pressure drilling is related in the West–Lindsey paper, (Ref. #3) originally presented at the 1968 Monahans, Texas, Deep Well Symposium. This paper states that more than 75% of the ultra-deep wells of West Texas have a pressure buildup on one, or more, of the casing strings, due to leaking connections on casing adjacent to high-pressure formations. Preventative maintenance was cited as the only solution, and it was suggested that high-pressure zones should be cased with threads having metal-to-metal seals, providing a bubble-tight shut off. Opposite normal-pressure formations, 8-Round T&C connections give satisfactory performance when properly cleaned, doped and made up.

Tension

Most casing joint ratings are less than the pipe body in Tension. Since joint strengths are based on material ultimate strength, rather than yield strength, joint yield should be considered when designing for Tension. Looking at simple Tension (weight in air, with no imposed load considered) and applying a safety factor of 1.6 to minimum ultimate strength of 7" 26#K-55 Buttress, Extreme Line or Super-EU, it is apparent that the joint yield strength will be exceeded in all three cases.

	Buttress	X-Line	Super-EU
		Joint Strength (Minimum Ultimate)	
A.	717,000	641,000	681,000
		With Safety Factor of 1.6	
B.	448,000	401,000	426,000
		Joint Strength (Minimum Yield)	
C.	415,000	383,000	371,000
		C ÷ B = Safety Factor for Yield	
	.926	.926	.926

One oil company stair-steps Tension safety factors, depending on material grade, as follows:

K-55 2.0 on minimum ultimate
1.16 on minimum yield

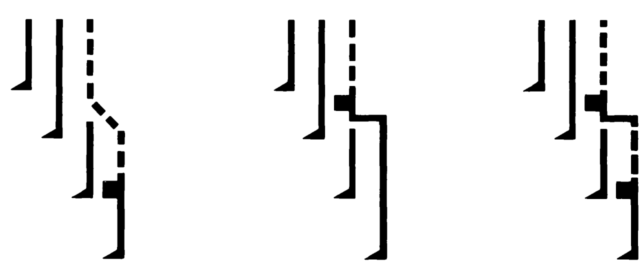
N-80 1.7 on minimum ultimate
1.30 on minimum yield

P-110 1.6 on minimum ultimate
1.4 on minimum yield

Deep well hindsight dictates that Tension safety factors for the production liner should be closely analyzed. As a rule, liner simple Tension safety factors are very high, but imposed loading can be severe and almost impossible to calculate. In the Gomez Field of the Delaware Basin, several production liners have failed in Tension during high-pressure treating, or fracturing, operations. The simple Tension load provided a high Tension safety factor, but the imposed Tension load caused by string contraction, due to cool acid, and ballooning, due to high internal pressure, induced tension failure. Two innovations which seem to have eliminated this problem in Gomez are:

1. Warming acid before introducing it into well bore.
2. Procuring a full pressure-rated connection that provides tension strength equal to, or approaching, that of the tube body.

Tension can also become a problem when designing tieback production casing using the low-strength material required for sour service. Three design approaches for tieback in ultra-deep wells are:



(1) Use tapered design (sizes and weights). (2) Set tapered liner, then tieback. (3) Set tieback in two pieces.

FIG. 5 — Tieback Design for Tension

Current development of higher strength material considered compatible with sour service and high-strength casing joints will permit the setting of longer, heavier strings.

COMPATIBILITY OF TUBULAR MATERIAL AND END FINISH WITH WELL ENVIRONMENTS

There have been numerous casing and tubing failures related to H_2S, or sour, environments. Many of these failures have been thoroughly investigated, and although much knowledge has been obtained from these investigations, they have also revealed the complexities of the problem. There are several factors upon which most metallurgist will agree; i.e., failure is a function of time under specific conditions in the presence of rather small amounts of H_2S; temperature, pressure and moisture can effect this time factor. Informative papers have been written on sulfide corrosion, hydrogen sulfide corrosion, hydrogen embrittlement, stress corrosion cracking and the all-encompassing hydrogen sulfide stress corrosion cracking. Within these papers, much discussion is devoted to the effects of stress.

Stresses – residual, induced, metallurgical, hoop-load, or whatever – are sources of trouble in H_2S service. Some of these stress sources are related to the manufacturing and handling of tubular goods and are controlled by good mill operating procedures and by mill and field inspection services. Induced stresses, particularly the axial tension type, can result in embrittlement failure of the most ductile tubular steel manufactured. One company places a tensile load percentage limitation on all casing and tubing used in sour service.

There is another source of introduced tension stress (hoop tension) that is directly related to the joint design. The thread designer develops torque resistance through thread interference, sometimes called "draw". This "draw" is also defined as the number of turns from the hand-tight plane to the power-tight plane on all connections, collared or integral type. The more interference, or wedging, that takes place during makeup, the more distortion. "Distortion" is defined as pin squeeze (hoop compression) and box, or collar, ballooning (hoop tension). The thicker the pipe wall, or the thinner the box (coupling), the more the distortion in the hoop tension direction.

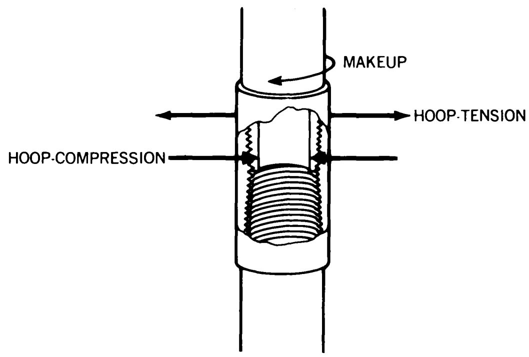


FIG. 6 — Distortion Due to Makeup

Most metallurgists do not worry about hoop compression distortion, but all worry about hoop tension distortion in sour service.

Many papers have been written incorporating refined, extensive calculations on converting thread interference to strain load, then to stress magnitude. With a uniform product and knowledge of draw and thread taper, there is an industry-accepted approach to calculating interference and converting the results to unit stress in the tension and compression directions:

$$\text{Interference (total distortion)} = \frac{\text{Taper per Foot}}{12''} \times \text{Draw}$$

Considering an assembled joint as a unit (100%), determining at a given point what percent of the total unit represents pin thickness and what percent represents box thickness, and knowing that distortion will be inversely proportionate, the designer can calculate what part of the distortion went into the pin and what portion into the box. This measurement is referred to as "strain". Once the strain is known, the unit stress can be calculated:

$$\text{Stress} = \frac{\text{Distortion in inches}}{\text{Effective Diameter}} \times \text{Youngs Modulus of Elasticity}$$

Thread interference presents a real dilemma for most thread designers. It is a source of torque resistance – in some connections, the only source – but, as the interference is increased for higher torque, so increases the hoop stress. If the hoop stress is reduced by reducing the amount of thread interference, the joint is torsionally weak. This dilemma is proven out by continuous changes in joint makeup torque, or turns.

The Carlson-Milo NACE article (Ref. #4), covering material recommendations for sour service, clearly points out that when selecting a joint for sour service, resulting hoop stresses and seal integrity must be considered.

Material selection, with respect to strength and hardness, is also of prime importance. There is a direct relationship between the hardness and ultimate strength of steels. Yield-ultimate ratios are characteristic of steel grades and are a measure of ductility. Generally, the lower yield material will have higher ductility and lower hardness values and will be more serviceable in sour environments. The desired mechanical properties are obtained through controlled chemistry and controlled heat treatment of the steel. With the right type of heat treatment, 55,000, 75,000 and 80,000 yield materials are considered compatible with H_2S. Investigation has shown that still higher strength materials endure in sour service at high temperatures. A recent breakthrough came in the development of a higher yield material – 90,000 psi, with a special chemistry and a hardness maximum of R_C25 – that may prove to be useable in sour service, particularly where pressure and tension requirements cannot be met with the lower yield materials.

HOLE AND PIPE SIZE COMBINATIONS

The discovery well is often the pace-setter for hole and pipe size combinations. The W.C. Tyrell #1 was the discovery well in the Gomez Field, Pecos County, Texas. Well depth was approximately 23,000 feet. It was also the first well in the Delaware Basin in which a 10 3/4" Intermediate was run in a 12 1/4" hole. Competent formation, minor hole enlargement due to washing, and a slim O.D. casing connection made this combination possible. The 10 3/4" was selected to permit the setting of two or three liners, as well as the use of popular bits. This is the area where the liner-tieback approach was first used to case ultra-deep wells. Casing programs in most of the Gomez wells are similar to the W.C. Tyrell's.

Next door to the Gomez Field, in Reeves County, Texas, there are several ultra-deep fields, in later stages of development, with formation characteristics, casing points and total depths very similar to Gomez. Their casing programs were also very similar, until one company set a 9 5/8" string in place of the 10 3/4" Intermediate, and ran a 7 5/8" drilling liner in an 8 1/2" hole below. This combination is still popular in Reeves, Winkler and Ward Counties of Texas, and Lea County, New Mexico.

The next development in hole size-pipe size combinations took place near Barstow, in Ward County, Texas. An 11 3/4" Intermediate was set in a 13 3/4" hole below 16" casing. This is not an unusual combination; however, below the 11 3/4", a high-pressure 9 5/8" drilling liner was set inside a 10 5/8" hole and tied back immediately. This size allowed a 7" or 7 5/8" liner to be set at T.D., and permitted room for a dual completion using two large tubing strings.

The 10 3/4"-12 1/4", 7 5/8"-8 1/2" and 9 5/8"-10 5/8" pipe-hole combinations have all been employed in the Anadarko Basin.

The September issue of the "Petroleum Engineer" reviewed a casing program outline for an Anadarko Basin well which could be the world's deepest well:

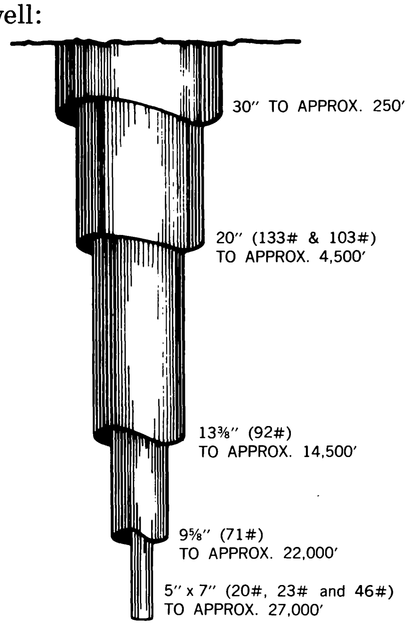


FIG. 7 — Tubular Program for Anadarko Basin Deep Well

As larger pipe sizes are set deeper, the tube wall thickness requirement reduces bit size possibilities; therefore, large pipe-small hole combinations are limited.

From this program emerges another hole size-pipe size possibility for future ultra-deep wells:

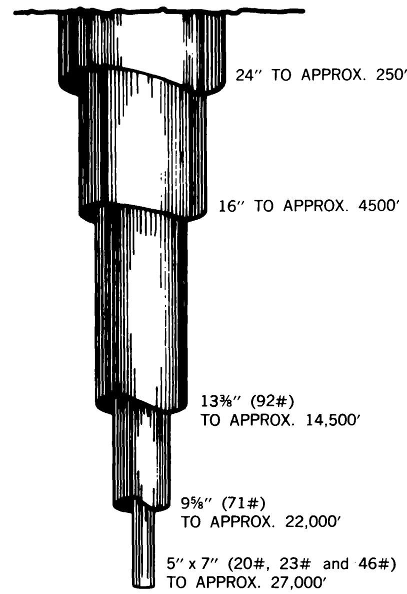


FIG. 8 — Possible Future Deep Well Tubular Program

Below 16" casing, in a 14 3/4" or 15" hole, a 13 3/8" Intermediate could be set using a slim-line connection that provides desired tensile property and seal integrity. The clearance provided between the 13 3/8" Intermediate casing and the 14 3/4" or 15" hole is similar to that between 10 3/4" Intermediate casing and a 12 1/4" hole – approximately 1". This design could reduce pipe and hole sizes above, as well as BOP stack sizes, drilling time, etc.

SUMMARY

Ultra-deep well tubular design considerations are constantly changing. It is extremely difficult to stay current on methods and techniques. Tubular design changes are taking place in both the Anadarko and Delaware Basins as this paper is being prepared. The intended purpose of this paper was to confront the designer with more recent design considerations as related to tubular products.

ACKNOWLEDGMENT

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