How and Why Tubing Anchors Reduce Operating Costs of Rod Pumped Wells

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ABSTRACT

The desirability of using a tubing anchor in a pumping well to increase effective pump stroke and to reduce wear on sucker rods, tubing and casing has been recognized for many years. It is well known that an unanchored tubing string "breathes" as a portion of the fluid load in the tubing is alternately transferred between the tubing and the sucker rods during the pumping cycle. The elimination of this movement of the tubing string by means of an effective anchor should provide obvious benefits to the operators of rod pumped wells. However, the use of tubing anchors in the past has, in general, given overall results that have been somewhat disappointing at best. In many cases there has been little or no increase in pump efficiency, and rod and tubing wear have continued to reduce appreciably the operator's margin of profit.

It has only recently been brought to light that the nature of the movement of the tubing string in a pumping well is much more complicated than the simple up-and-down breathing motion previously envisioned. In fact, in nearly all wells the lower portion of the tubing string buckles around the sucker rods in spiral fashion on each upstroke of the pump. It is this previously unknown buckling that accounts for the disappointing results of anchoring tubing in the past. Armed with the knowledge that a tubing string must be anchored in tension to completely eliminate the harmful effects of buckling as well as breathing, oil field equipment manufacturers have made available to the industry properly designed tubing anchors which, when coupled with the proper setting techniques for this equipment, now make it possible to achieve the results that were anticipated many years ago.

INTRODUCTION

The phenomenon of cyclic breathing of tubing strings in rod pumped wells is well known, and the use of tubing anchors to prevent this motion has long enjoyed universal acceptance. However, the actual benefits realized have rarely lived up to expectations. Compression type anchors have been most widely used, and even thought the overall results have been somewhat disappointing, operators have continued to use them for the prevention of tubing breathing as well as for their secondary function as catchers should the tubing string part or be dropped. The theory of setting down tubing weight on a compression type anchor as a means of preventing tubing breathing is sound but, unfortunately, it has been a case of only partial knowledge of the complete problem.

In their excellent recent paper, Lubinski and Blenkarn[1] made known three major points in regard to down hole pumping problems. First, the lower portion of a freely suspended tubing string in a rod pumped well buckles around the sucker rods in spiral fashion on each upstroke of the pump; second, tubing must be anchored in tension to prevent buckling; and third, in nearly every case the effects of tubing buckling dictate far more serious consideration than do the effects of tubing breathing.

With the exception of the Lubinski-Blenkarn report, very little has been written on the subject of anchoring tubing strings in rod pumped wells. It is strongly felt that the proper application of present day knowledge in this regard will be reflected in significant reductions in "normal" operating costs and in increased profits.

The author's purpose in writing this paper is to provide a single source of reference that contains a review of the factors that create the need for tubing anchors, a discussion of the merits and limitations of the basic types of tubing anchors available to the industry, and sufficient, easily applied data to insure that field personnel will be able to utilize current tubing anchoring knowledge to its fullest advantage.

THE PROBLEM OF TUBING MOVEMENT IN ROD PUMPED WELLS

In order to thoroughly understand the need for tubing anchors and their proper use in rod pumped wells, it is in order to begin with a discussion of the various factors which cause tubing movement when a well is pumped. The three basic forms of tubing movement which must be considered are elongation, breathing and buckling.

Tubing Elongation

Tubing elongation in itself has no detrimental effects, but the fact that it occurs should be recognized and taken into account in anchoring a tubing string. Elongation occurs as the result of increased fluid load on the standing valve, decreased buoyancy and thermal expansion.

Fluid Load Elongation

Fluid load elongation is the result of the filling of the tubing with fluid as the well pumps up. The magnitude of the fluid load is, among other things, a function of the density (weight per unit volume) of the produced fluid. Therefore, in a well in which the water percentage or "cut" is increasing, additional tubing elongation takes place with the passage of time.

Buoyancy Decrease Elongation

Buoyancy decrease elongation is caused by the lowering of the annulus fluid level when a well is placed on production. The distance the fluid level is lowered in any given case is approximately proportionate to the rate at which a well is produced. Tubing in wells that are not normally pumped off - that is where the operating fluid level remains above the pump - will suffer additional elongation as a result of either or both increased production rate and decrease in reservoir pressure. In limited reservoirs with relatively high pressure decline rates, the latter point is worthy of special consideration when setting a tubing anchor.

Thermal Elongation

Thermal elongation results from the raising of the temperature of the tubing by the relatively hot produced fluid and is to some degree affected by the production rate. This point is discussed further in the Appendix.

TUBING BREATHING

Tubing "breathing" is a common oil field term that describes the up-and-down motion of an unanchored tubing string as fluid load in the tubing is alternately transferred between the tubing and the sucker rods during the pumping cycle.

During each downstroke of the pump when the traveling valve is open and the standing valve is closed, a downward force is exerted on the tubing string at the level of the pump that is equal to the pressure differential across the closed standing valve times the cross sectional area of the tubing inside diameter. That downward force causes the tubing to elongate.

During each upstroke of the pump when the traveling valve is closed and the standing valve is open, a portion of the total fluid load supported by the tubing during pump downstroke is transferred to the sucker rod string and, as a result, the tubing string contracts. The amount of the reduction in load on the tubing string is equal to the pressure differential across the traveling valve times the cross sectional area of the pump plunger. It therefore follows that the magnitude of the load change on the tubing during the pumping cycle is a direct function of the pump plunger cross sectional area. The larger the diameter of the plunger, the greater the load change; hence, the greater the elongation and contraction or "breathing" distance of the tubing.

Influence Of Plunger Size

The influence of plunger size on tubing breathing becomes particularly noticeable in the special case where an extra large diameter pump is used to obtain high production rates. (The term "extra large" is used here to mean a pump plunger diameter that is greater than the inside diameter of the tubing.) During upstroke of an extra large plunger, all of the fluid load that caused the tubing to elongate is transferred to the rod string and, in addition, a force comes into being that exerts an upward lift on the tubing at the point where the reduction to tubing inside diameter occurs. That upward force is equal to the pressure in the tubing at that point times the differential area between the plunger outside diameter and tubing inside diameter. Thus it can be seen that an "extra large" plunger may seriously aggravate tubing breathing.

Disregarding the dampening effect of friction between the tubing and casing, the entire tubing string is influenced by the "breathing" action. Each joint of tubing in the string stretches and contracts an equal amount, but the amount of movement is additive. For example, assume that each joint of tubing stretches and contracts 1/8 of an inch during one complete cycle of the pump. The coupling connecting the top two joints of tubing will travel a distance of 1/8 of an inch. The next coupling down will travel two times 1/8 of an inch, or 1/4 of an inch, because the stretch of the second joint of tubing will be added to that of the first joint of tubing. Each coupling in the string will have 1/8 of an inch greater up-and-down motion than the one immediately above it, which results in the maximum breathing motion occurring at the level of the pump where the load change is taking place.

The most apparent detrimental effects of breathing are tubing and casing wear and decrease in effective pump stroke. The decrease in effective pump stroke is probably less obvious than the wear effect, but it is easily understood. As the plunger starts its upward travel, the load transfer to the sucker rods takes place. The resultant tubing contraction causes the pump barrel to move upward also. Then as the plunger starts downward, the load transfer reverses to the tubing with the result that the pump barrel moves downward with the plunger. The movement of the pump barrel in the same direction as the pump plunger on both upstroke and downstroke subtracts directly from the plunger stroke. In other words, the effective plunger stroke is the actual plunger stroke less the distance the pump barrel breathes.

TUBING BUCKLING

Tubing buckling is a recently discovered phenomenon that could be defined as the corkscrew configuration assumed by the lower portion of a freely suspended tubing string during pump upstroke in a rod pumped well.

Now that its existence is known, the reasons for the generally disappointing results of anchoring tubing in the past become quite apparent. In most cases, buckling is a greater contributor to wear and loss of efficiency than breathing. Unfortunately, the widely accepted method of anchoring tubing to prevent breathing with a compression or set down type anchor, with little or no tailpipe run below it, does not prevent buckling; in fact, it aggravates buckling to the extent that most of the benefits that should be realized through prevention of breathing are cancelled.

Probably the main reason for buckling remaining unknown as long as it did is that the resultant effects of breathing and buckling are quite similar. Now that both factors are known to be the cause of the problems heretofore attributed solely to tubing breathing, effective preventive action can be taken and the desired results achieved. (The discussion of tubing buckling presented herein is basically a review of AIME paper T.P. 4482, "Buckling of Tubing in Pumping Wells, Its Effects and Means for Controlling It" by Arthur Lubinski and K. A. Blenkarn of the Pan American Petroleum Corp., Tulsa, Oklahoma. In view of the existence of that rigorous and thorough treatment of the subject, it is felt that tubing buckling need only be covered here in sufficient detail to develop an understanding of its effects and how to prevent it. For those desiring a complete knowledge of tubing buckling, the above mentioned paper is highly recommended.)

Causes of Buckling

Before actually considering tubing buckling in rod pumped wells, it is in order to first show what causes it to occur. First, assume that a pipe with closed ends is resting on supports at each end. (See Fig. 1). Gravity causes the pipe to bend. When internal pressure is applied to the pipe, the pressure forces acting on the closed ends subject the pipe to tension and tend to straighten it.

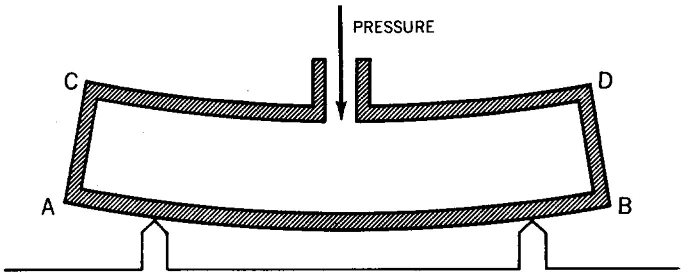


Fig. 1

However, it must be remembered that the internal pressure also acts on the pipe walls as well as on the ends. Since the bend in the pipe causes the bottom side A-B to be longer than the top side C-D, there is more area along the outside of the curve of the pipe than there is along the inside of the curve and, therefore, more side force tending to increase the bend than there is side force tending to straighten it. In other words, the net force of the pressure acting on the pipe walls tends to bend it further. The opposing effects of the forces tending to straighten the pipe and the force tending to bend it further are equally balanced and the pipe will remain in the position that it assumed before pressure was applied. (The proof of this statement is published in the Appendix of Reference 2.)

Now assume that a similar pipe is supported in the same manner; the difference being that the inside diameter of this pipe is reduced slightly at each end, and the end closure is provided by pistons that are connected to prevent their being expelled by pressure. (See Fig. 2). When internal pressure is applied to this pipe, the balance of forces of Fig. 1 no longer exists. The areas of the pistons reduce the effective end areas upon which pressure can act to produce tension in the pipe, and as a consequence, there is less straightening tendency. Since the side force tending to increase the bend in the pipe remains unchanged by the substitution of pistons for solid ends, while the forces that create the tension that tends to straighten it are reduced, the side force predominates and the amount of bend in the pipe increases with the application of internal pressure.

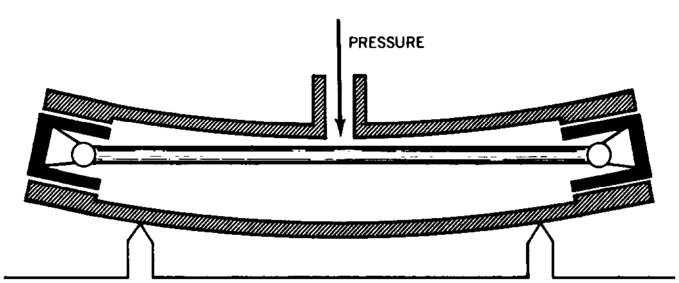


Fig. 2

A question might arise regarding the validity of the foregoing assumption that the pipe has an initial bend, especially since the pressure force that buckles the pipe is the direct result of the difference in side areas created by the bend. It seems logical that if the pipe were perfectly straight, internal pressure would not cause a side thrust and the pipe would remain straight. However, that would be a condition of unstable equilibrium because even the slightest amount of bend would cause the side force to appear, and with its appearance the pipe would commence to buckle. Simultaneously, an elastic reaction would appear that would tend to straighten the pipe. The stronger of the two tendencies determines whether the pipe buckles or remains essentially straight. At some value of internal pressure a critical point is reached where the buckling tendency becomes greater than the straightening tendency and the pipe buckles.

Determination Of Buckling Force

Buckling occurs as though the pipe were subjected to a column or end load instead of internal pressure. Although a column load actually does not exist when the pipe is pressured internally, the existence of the analogy greatly simplifies the determination of the buckling force. It is shown in the literature that the buckling force is equal to the applied pressure times the area of the piston effecting the end closure of the pipe.

If the foregoing theory is now applied to a pumping well, as shown in Fig. 3, it is apparent that during pump upstroke, when the standing valve is open and the traveling valve is closed, the plunger acts in the same way as the pistons of Fig. 2. If the internal pressure is great enough, the tubing will buckle as if subjected to an end or column load that is equal to the pressure differential across the plunger (pressure above it minus the pressure below it) times the cross-sectional area of the plunger. During the downstroke of the pump, when the traveling valve is open and the standing valve is closed, the entire end area of the tubing becomes effective. The resultant increase in tensile force balances the buckling force, and the tubing straightens.

Most operators are probably well aware that a drilling string buckles due to setdown weight which is actually an upward column load. The buckling of a tubing string is very similar. Both strings buckle only below a so-called neutral point and both are essentially straight above it. The calculation of the distance to the neutral point of a tubing string is not as simple as that of the buckling force; and since its determination is not required in the fulfillment of the purpose of this paper, it will not be discussed here. It is sufficient to recognize that buckling occurs only in the lower portion of the tubing string in rod pumped wells. (Those actually interested in the determination of the neutral point are referred to Reference 1.)

It has been stated previously that the buckling force must exceed some critical value in order for buckling to occur. Comparisons of actual values of buckling force versus critical force shows that the tubing buckles in all rod pumped wells except those with

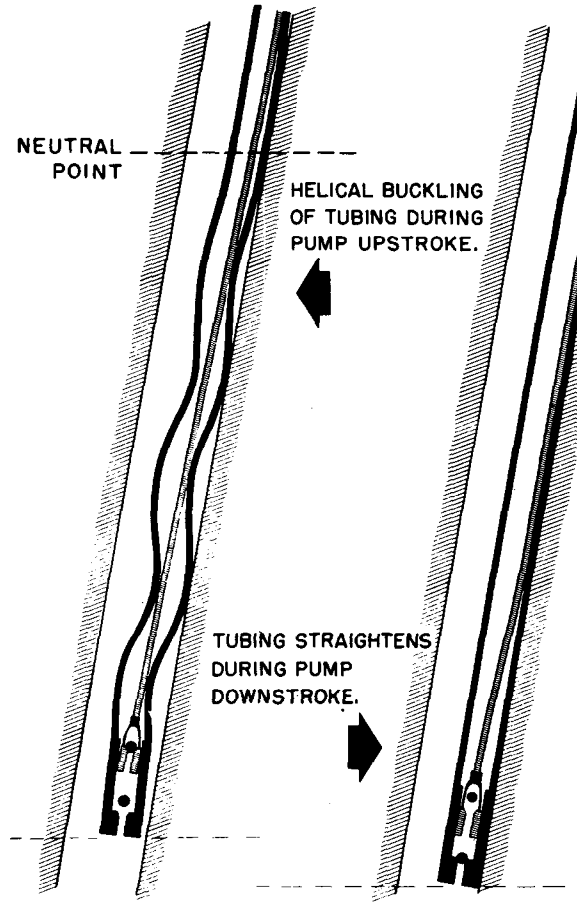


Fig. 3

very high operating fluid levels. In most wells with low operating fluid levels, the buckling force that results from the large pressure differential across the plunger is so much greater than the critical force that very severe buckling results. Where severe buckling occurs, the tubing corkscrews around the sucker rod string during upstroke and is in continuous contact with it over the entire distance between the pump and the neutral point. At that time the rod string is under great tension because of the fluid load it is supporting and, therefore, remains essentially straight in spite of the side forces exerted upon it by the buckled tubing. It is only natural that a great deal of rod on tubing friction should result. Another highly probable result is accelerated pump wear caused by the buckled tubing and essentially straight rod string tending to force the pump plunger to cock in the pump barrel.

Detrimental Effects Of Tubing Buckling

Considering the foregoing, it appears that the following statements can be made regarding the detrimental effects of tubing buckling:

1. Rod on tubing friction below the neutral point may cause excessive wear. (See Fig. 4 taken from Reference 3).
2. Rod-on-tubing friction may result in greater rod loads than anticipated, which increases the probability of rod failures as well as necessitating increased horsepower requirements.
3. Excessive rod loads resulting from rod on tubing friction results in decreased plunger travel and apparently low pump volumetric efficiency.

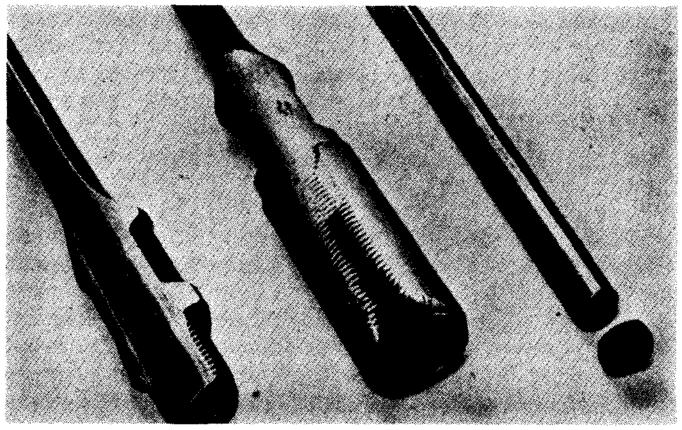


Fig. 4

4. Tubing buckling may cause external tubing wear (See Fig. 5) and internal casing wear.
5. Tubing buckling may cause tubing leaks as a result of repeated flexing.
6. Tubing buckling may reduce pump life, because of the cocking tendency of the plunger in the pump barrel.

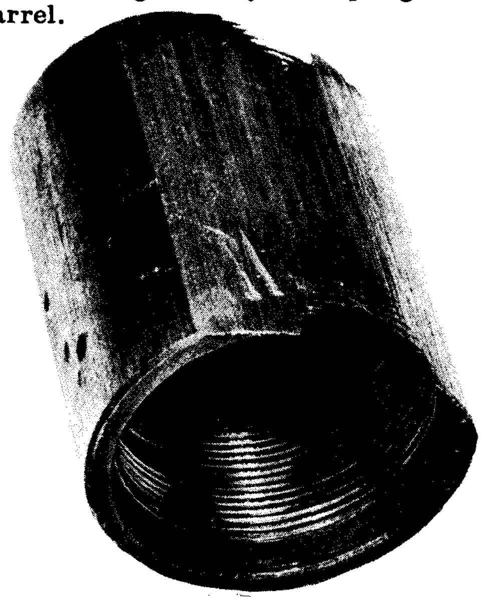


Fig. 5

Data included in the Lubinski-Blenkarn paper* plus other data in reports from operators who have eliminated tubing buckling indicate that all of the above statements are well founded. It is only natural, however, that the effects of buckling will vary from well to well as down-hole conditions differ.

Some operators may be inclined to disagree with the foregoing and also with the statement that tubing buckles in all wells except those with very high operating fluid levels, because they have not had the problems associated with buckled tubing. However, there is a reasonable explanation for this apparent discrepancy. The fundamental effect of tubing buckling is wear, and wear is primarily a function of abrasion and corrosion. In the absence of sand or other abrasives in the pumped fluid, and particularly where corrosion is also not a problem, the rate of wear may be low enough to be accepted as normal. It has also been found that in wells in which corrosion inhibitors are used, wear is generally a relatively minor problem. This is probably due to the degree of lubrication and consequent reduction of friction that results from the use of inhibitors.

SOLVING THE PROBLEM

Prevention Of Buckling

Assuming now that the phenomenon of tubing buckling is established, the next step is to determine how it can be prevented. Three important points must be remembered in order to arrive at the desired solution. First, tubing buckles during pump upstroke and straightens during pump downstroke; second, buckling occurs as though an upward column load or force is applied to the bottom of the tubing string; and third, the apparent upward buckling force is equal to the pressure differential across the standing valve (the pressure above it minus the pressure below it) times the cross sectional area of the pump plunger.

Also remember that, in the case of the pipe shown in Fig. 1, although a net pressure force existed that tended to bend or buckle the pipe further, the pressure forces acting on the closed ends of the pipe provided just enough straightening tendency or tension to exactly balance the buckling tendency. The loss of any part of that effective end area, as in the case in Fig. 2 where the pipe end closure is affected by pistons, reduces the tension in the pipe and unbalances the straightening and buckling tendencies in favor of buckling.

Now consider again the tubing string in a rod-pumped well. During pump downstroke when the standing valve is closed, the fluid load elongates the tubing and provides just the right amount of tension to keep it from buckling. If the bottom of the tubing were held at its downstroke position during pump upstroke, the precise amount of tension required to prevent buckling would still be maintained during pump upstroke.

It therefore follows that the proper type of tubing anchor for the prevention of buckling is one that will hold the tubing at its most elongated position; in other words, a tension anchor. This is in direct contrast to a compression or set down anchor which permits tubing to contract but not elongate; in which case the tubing could buckle not only during the upstroke of the pump, but during its downstroke as well.

In the light of the increased present day knowledge of tubing string movements in rod pumped wells, it is now possible to make a better evaluation of the various types of tubing anchors available to the industry. Following are some thoughts in regard to the more popular types.

COMPRESSION ANCHOR

This type of anchor, which might also be called a set down anchor, permits the tubing to move upward but prevents downward motion. An immediately apparent advantage of the compression anchor is that it should be easy to retrieve. It also can be used to support part of the weight of a long string of tubing, and it will act as a tubing catcher, should the tubing part or be dropped during retrieving.

A compression anchor by itself will prevent tubing breathing but will not prevent buckling. In fact, unless a heavy tailpipe is run below it, it will cause tubing buckling that is much more severe than in freely suspended tubing.

Since the anchor is normally set before pumping is started, the natural tubing elongation caused by increased fluid load, decreased buoyancy and temperature expansion is prevented. (See Fig. 6). Therefore, the

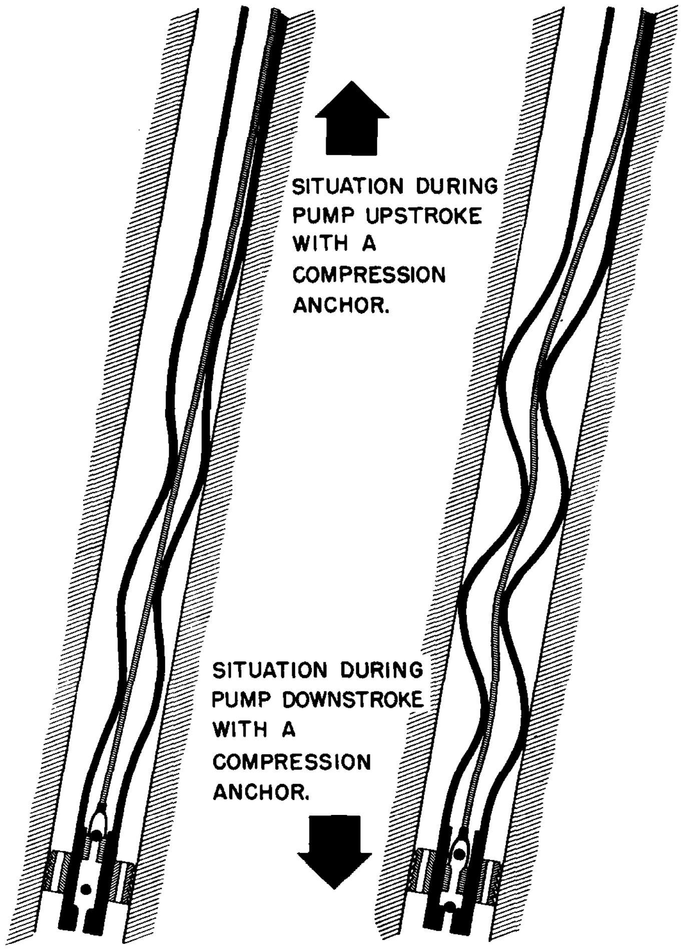


Fig. 6

set down load on the anchor, or upward load on the tubing, will be substantially greater when the well is pumping than when the anchor was first set. During upstroke, the deflection of the helically buckled tubing is limited by the essentially straight, heavily loaded rod string. During downstroke, the tubing cannot elongate and the fluid load that causes a freely suspended tubing string to straighten is instead transferred to the casing through the anchor, with the result that the tubing remains buckled.

Moreover, since the sucker rods are no longer under great tension, the deflection or buckling of the tubing increases, since it is then limited by the relatively large inside diameter of the casing rather than by the straightened rod string. The severity of the downstroke buckling may cause fatigue failures and coupling leaks as well as tubing and casing wear. The downstroke buckling also hinders rod fall, causes rod deflection, reduces plunger travel, and may even cause some of the rods to be under compression. The effect of the buckled tubing on the sucker rods increases the probability of rod fatigue failures and rod wear.

If a compression anchor is run some distance above the pump as shown in Fig. 7, tubing breathing is reduced to only that portion of the tubing string below the anchor, but upstroke buckling would still occur between the pump and the anchor. Also, thermal elongation contributes to both upstroke and downstroke buckling of the tubing above the anchor if it is not run very high above the pump.

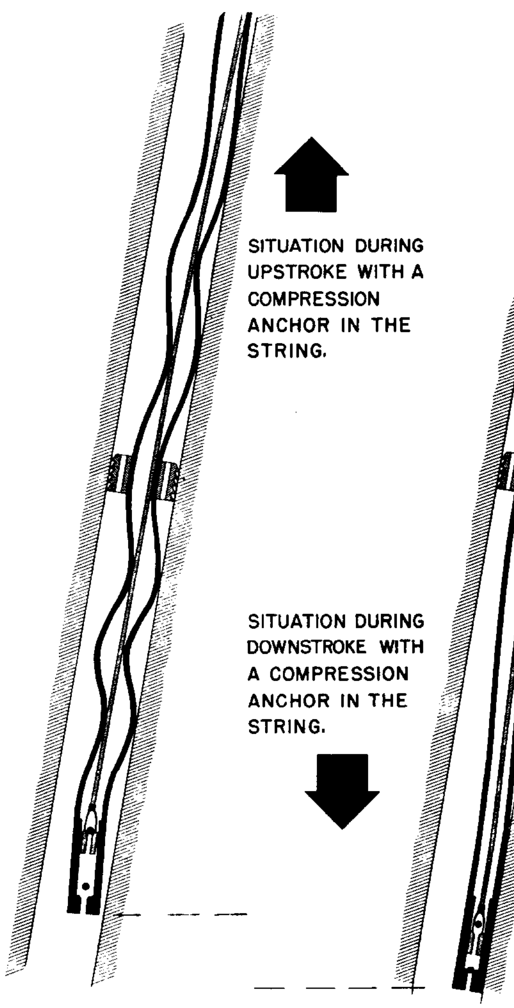


Fig. 7

From the foregoing it is quite evident why past results of the use of compression anchors have often been disappointing, even though detrimental tubing breathing was eliminated.

Anchor Set At Pump Depth

Breathing and buckling will be prevented when a compression anchor is set at pump depth, provided a sufficiently heavy tailpipe is run below the pump and anchor. The tailpipe prestretches the tubing before the anchor is set, to allow for the elongation that occurs after pumping is started. The required tailpipe weight in fluid is approximately equal to the calculated buckling force plus the thermal elongation force. (The thermal elongation force is shown as "F_3" in Figs. 9, 10 and 11 in the Appendix.) Calculations for an actual case will show that the tailpipe weight must be much greater than would probably be imagined. The use of a tailpipe below the pump and compression anchor may be impractical, due to insufficient room below the pump or danger of it becoming sanded in. It must also be remembered that the tensile load on the tubing is increased by the amount of the weight of the tailpipe.

HYDRAULIC PISTON ANCHOR

This classification designates anchors in which the holding force results from tubing pressure acting on one or more horizontal pistons, which either contact the casing directly or force a separate member or members to contact the casing. The contact surfaces are generally wickered or otherwise altered to increase the holding power of the anchor. The holding power is always great enough to prevent tubing breathing, and may be great enough to prevent normal tubing elongation.

If it is great enough to prevent tubing elongation, both upstroke and downstroke buckling will occur, although it will be less severe than for a compression type anchor used without a tailpipe, since part of the total normal elongation will take place before sufficient tubing pressure is developed to set the anchor.

If this type of anchor does not have sufficient holding power to prevent normal tubing elongation, it would still hinder it to the extent that the tubing would not reach its lowermost position of natural elongation, and at least some buckling would occur. Elongation would take place in successive jumps whenever the elongation force overcame the holding force of the anchor. It would seem that both the casing and the contact surfaces of the anchor might suffer some damage as a result of the jumps.

Smooth Contact Surfaces

At least one version of the hydraulic piston type anchor has smooth contact surfaces, and its holding power is obtained strictly as a result of friction with the casing. It probably permits partial elongation, as described above, with much less possibility of damage to either the casing or the anchor.

Since its holding power is a function of tubing pressure, a hydraulic piston anchor type must be run above the pump. Some type of fluid unloading device should also be used in conjunction with it, if this feature is not already incorporated in the anchor, to insure that it can be released in case the pump should become sanded in. The additional cost of a separate fluid unloader should be considered as part of the cost of the type of anchor.

Some operators gain improved operating conditions by setting down the weight of the rods to prestretch the tubing and then filling the tubing with water to set the anchor. It appears that this should be a recommended method for setting a hydraulic piston type anchor, as it would greatly minimize tubing buckling.

CONVENTIONAL TENSION ANCHOR

A tension anchor is the direct opposite of a compression anchor. That is, it will allow tubing to move downward but it prevents upward motion. The fact that downward motion only is allowed might be considered hazardous in regard to retrievability, but tension anchor manufacturers take this into consideration in anchor design and most, if not all, provide one or more emergency release methods in addition to the normal method of releasing to insure retrievability. The emergency release is normally effected by shearing some member of predetermined strength with an appropriate upward pull on the tubing.

It might seem that a tension anchor could simply be set without further thought as soon as the tubing is run in the well. During the normal course of tubing elongation the anchor would move down on each downstroke and hold on each upstroke to prevent upstroke breathing and buckling. There is, however, a factor inherent in the design of conventional tension anchors that does not make this setting method seem attractive.

All conventional tension anchors require a certain amount of upward motion to make the slips engage the casing, and if this motion with its resultant shock load were allowed to be repeated continuously, damage to the casing and anchor slippage might result. It follows then that the correct procedure to follow, in setting a conventional tension anchor, is to cause the slips to engage the casing and then prestretch and land the tubing with sufficient tension to compensate for those factors which cause elongation after pumping is started. The method for determining the proper amount of tension to be applied to the tubing is given in the Appendix.

The well data required for the determination of the proper amount of prestretch includes the fluid level when the anchor is set, the operating fluid level, the average temperature increase of the tubing string and the density of the pumped fluid. Since any or all of these are rarely known accurately, the calculated prestretch is at best only an approximation of the actual prestretch that should be applied to the tubing. In addition, changes in fluid density and decreasing reservoir pressure during the time the anchor is in operation are other possible sources of error in determining the proper amount of prestretch for the tubing. Therefore, some safety margin of additional prestretch should be applied at the time the anchor is set to eliminate the possibility of the previously mentioned anchor slippage and damage to the casing that could occur if the anchor were to walk down the hole.

Tubing Hanger

Another factor to be considered is the type of tubing hanger involved. Slip type hangers are best suited for this application; flange hangers or "doughnut" hangers present somewhat of a problem in hanging tubing strings with predetermined amounts of tension considering the necessary overstretching, use of tubing pup joints and calculations required to arrive at the desired tension when the tubing is finally landed.

In some cases, the tension required to properly set a conventional tension type tubing anchor may endanger the tubing string. It might appear that the procedure to follow in this case would be to take a safe pull, land the tubing and let it go at that. This is not true, however, as the anchor will automatically walk down the hole during pumping as the tubing elongates. In addition to the already mentioned undesirable effects of letting this type of anchor walk down the hole, when pumping is later stopped, the cooling of the tubing and draining of its fluid will cause the same amount of tension in the tubing as there would have been if it had been prestretched the proper amount in the beginning. This means that if the indicated proper amount of tension will endanger the tubing string, a tension type anchor should not be used.

A further point to remember is that the prestretch of the tubing should always be applied to the tubing in inches of stretch, not in pounds of pull according to the weight indicator, because of probable friction between the tubing and casing.

Friction, in effect, reduces the amount of tubing being prestretched so the actual pickup in pounds, required for a given pickup in inches, may exceed the calculated pickup in pounds that is required to prevent buckling. Subsequent vibration of the tubing during pumping reduces the friction and also any extra tension initially applied because of friction. Therefore, if the pickup to prestretch the tubing is made in inches, the final resulting tension will be more nearly correct. Conversion of the calculated pounds of pull to inches of stretch can be made using readily available tubing stretch charts.

The major part of the preceding discussion may seem to dwell primarily on problems associated with conventional tension type tubing anchors, but it is felt that its advantages will already be understood at this point; for indeed, a properly set tension type tubing anchor will provide the maximum possible benefits attainable through tubing anchoring. It is intended that the discussion of possible associated problems will enable operators to use tension type anchors on an intelligent and safe basis.

AUTOMATIC TENSION ANCHOR

An automatic tension anchor is similar to a conventional tension anchor in that both permit tubing elongation but prevent upward movement. The distinguishing feature of an automatic tension anchor is that its slips are forced to maintain contact with the casing and the cone on the anchor at all times, once the tool is set. (See Fig. 8). Therefore, slip

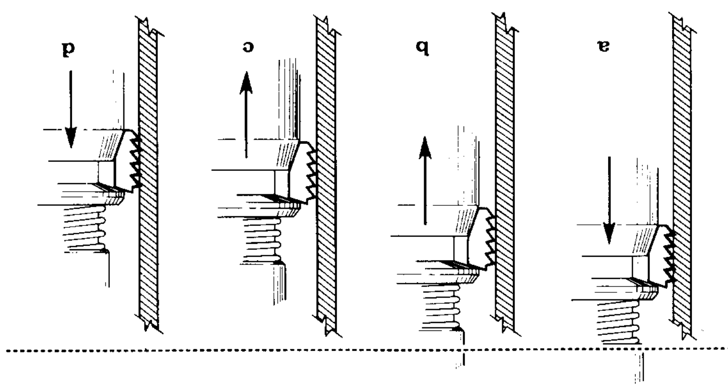


Fig. 8

engagement with the casing takes place the instant upward movement of the tubing begins. Since upward movement and resultant impact loading during pumping cannot take place, it is perfectly safe to allow an automatic tension anchor to walk down the hole as a result of the natural elongation of the tubing. In fact, that is exactly what it is designed to do.

The operation of an automatic tension anchor is described in the following sentences.

As the tubing elongates on each downstroke, due to those previously explained forces which occur after pumping of the well is started, the automatic tension anchor (which is sometimes called a compensating anchor) automatically adjusts to the lowermost point of travel of the bottom of the tubing string and anchors the tubing in that position. As pumping continues, the tension at the top of the tubing string during each upstroke remains unchanged from the preceding downstroke. At the time the upstroke of the pump reduces the fluid weight against the bottom of the tubing, the anchor automatically assumes this force to maintain the tension in the tubing necessary to eliminate buckling and breathing.

This action continues, increasing tension with each complete pump cycle just sufficiently to overcome the increasing buckling tendency of the tubing as the internal pressure becomes greater, until maximum elongation of the tubing is reached. For the existing set of well conditions, the tubing is then in precisely the correct amount of tension to eliminate buckling and breathing. Further elongation of the tubing, due to changing well conditions, is automatically compensated for by a proportionate increase in tension that again is the minimum amount necessary to eliminate buckling.

An automatic or compensating tension anchor in operation does not pull tubing down the hole. It has no motivating force or pulling power of its own, so a tubing string anchored with an automatic tension anchor elongates the same amount as a freely suspended tubing string under the same well conditions. Therefore, the maximum tensile load imposed on the tubing during pumping is the same for a tubing string anchored with an automatic tension anchor as it is for a freely suspended tubing string. The anchor, however, maintains a constant tensile load on the tubing string during pumping, whereas the load on freely suspended tubing is reduced during each pump upstroke and increased during each pump downstroke. That cyclic load change on freely suspended tubing is a major cause of tubing coupling leaks.

It is true, however, that the tensile load imposed on a tubing string anchored in this manner will be greater than that for freely suspended tubing if pumping is stopped, due to the thermal contraction of the tubing when it cools. The amount of the thermal contraction force is "F_2" in Figs. 9, 10 and 11 in the Appendix. It is to be understood, however, that the maximum tensile load imposed by an automatic tension anchor is no more than it would be for a conventional tension anchor under the same conditions, since that load would have to be applied during the setting of the latter type. In fact, the conventional tension anchor load would probably be somewhat greater because of the necessity of applying an extra safety margin of load, for reasons discussed previously.

<u>Simplicity In Use</u>

The primary advantage of an automatic tension anchor over a conventional tension anchor is its simplicity in use. The procuring of the accurate data required for conventional tension anchors is not required and calculations and special tubing landing operations do not have to be performed.

A reasonable approximation of the possible tubing tension should be made, however, since automatic tension anchors generally incorporate some type of shear member as an emergency release feature, it would obviously be undesirable to have that shear member fail due to thermal contraction of the tubing and release the anchor just because the well is temporarily shut down. Also, it is important to determine whether or not the tubing string has sufficient strength for the tensile load that it may have to support.

There is some feeling that the slips of an automatic anchor might become inoperative due to plugging of the teeth of the slips with rust and scale as the anchor moves progressively downward. It may be true that a conventional tension anchor should be preferred in wells with very heavy scale deposits, but extensive field tests indicate that the slips designed for use on automatic anchors operate successfully under nearly all conditions.

BENEFICIAL RESULTS OF PROPER TUBING ANCHORING

In viewing the overall picture, it appears that a tubing anchor should be considered as essential as the pump itself in nearly every rod pumped well, rather than being regarded as an item of accessory equipment. The possible benefits to be derived through the elimination of tubing buckling and breathing are many in number and, though the relative gain varies over a wide range in individual cases, it appears quite probable that there would be a resultant profit in nearly every case.

A significant portion of rod pumped well operating costs are for well servicing, which is meant here to include pulling costs, cost of equipment repair and replacement for such items as rods and rod couplings, tubing and tubing couplings, pumps, and possibly even deferment of income resulting from well down time for servicing. Only a very small reduction in well servicing frequency is required to return the cost of a tubing anchor and affect a reduction in operating costs.

Naturally a reduction in operating costs is reflected in the form of increased profits, but there are other attendant results which may also appear in the form of increased profits. For example, ultimate reservoir recovery may be increased. It is well known that the oil recovered from most reservoirs represents only a relatively small percentage of the total oil in place, say, of the order of 15 to 40 per cent. Since most oil reservoirs are produced by rod pumped wells, at least in the final stages of depletion, reductions in operating costs of rod pumped wells allow more oil to be produced from any given reservoir. This is true because the factor that establishes the end point in the life of a producing reservoir is its economic limit, and reduced operating costs lower the economic limit, which permits the production of additional oil before operations must be suspended.

CONCLUSIONS

1. The lower portion of freely suspended or improperly anchored tubing strings buckles and wraps around the sucker rods during pump upstroke in all rod pumped wells except those with very high operating fluid levels.

2. The side thrust caused by buckled tubing is extremely detrimental, in that it may be responsible for the following:
   1) Excessive tubing wear, tubing leaks and tubing failures.
   2) Excessive rod wear, rod loads and rod failures.
   3) Excessive casing wear.
   4) Increased input horsepower requirements.
   5) Reduction of pump life.
   6) Reduction of overall pumping efficiency.

3. The detrimental effects of tubing buckling can be eliminated only by providing tension in the tubing string to offset the buckling force. Tubing breathing is automatically eliminated when buckling is prevented.

4. A compression type anchor will not prevent tubing buckling unless the anchor is set at pump depth and, in addition, unless a very heavy tail pipe is run below it.

5. A hydraulic piston type anchor prevents tubing breathing and will minimize buckling effects particularly if the rod string is set down to prestretch the tubing before setting the anchor.

6. Conventional tension type anchors will completely eliminate both breathing and buckling, provided the tubing is landed with sufficient tension in it. Means for determining the proper amount of tension are given in the Appendix.

7. Automatic tension anchors completely eliminate both tubing breathing and buckling, and are the simplest to use because predetermination of proper tension and special tubing landing operations are not required.

8. All tension type anchors should have safety features to insure retrievability.

9. Tubing strength should always be considered before using any tension type anchor. Tubing strength in relation to anchoring tension is discussed in the Appendix.

10. Significant reductions in operating costs of rod pumped wells, as well as increased profits, should be realized through the elimination of tubing buckling and breathing.

REFERENCES

1. Lubinski, Arthur and Blenkarn, K. A.: "Buckling of Tubing in Pumping Wells, Its Effects and Means of Controlling It," paper presented at the AIME Petroleum Branch Fall Meeting in Los Angeles, California, October 14-17, 1956. Published in the Journal of Petroleum Technology, March 1957.

2. Texter, H. G.: "Various Methods of High Pressure Testing Oil Country Tubular Material," preprint of paper presented at the American Society of Mechanical Engineers, Petroleum Division Conference, Kansas City, Missouri, September 1952.

3. Eastman, H. John: "Producing Directionally Drilled Wells", Published by Eastman Oil Well Survey Co., Denver, Colorado.

APPENDIX

Prestretching Tubing To Prevent Buckling

It is explained in the body of the paper that during pump upstroke, freely suspended tubing buckles as if it were subjected to an upward column or end load that is equal to the pressure differential across the closed standing valve times the plunger cross sectional area. Since the apparent upward load at the level of the pump is responsible for the buckling condition, buckling would not occur if an equal and opposite acting force were applied at the level of the pump to counteract the apparent upward load. The equal and opposite force would provide a straightening effect by creating tension in the tubing.

It has been shown that the precise amount of tension required to prevent buckling exists in freely suspended tubing at pump level during downstroke. If the tubing is held at its most extended downstroke position during pump upstroke, the equal and opposite action force is developed at pump level during upstroke, and buckling will not occur.

It follows that if tubing is properly anchored, the tubing anchor is required to exert a pull on the tubing only during pump upstroke. In order to arrive at this condition when using a conventional tension type tubing anchor, it is necessary to land the tubing with sufficient prestretch in it to compensate for the elongation of the tubing string that takes place after pumping is started. It is important that at least the minimum required prestretch is applied in landing the tubing to prevent a conventional tension type anchor from walking down the hole as elongation occurs. As explained in the body of this paper, conventional tension type anchors are not designed to operate in this manner.

Tubing Pickup Determination

The Lubinski-Blenkarn paper[1] gives the complete formula and its derivation for calculating correct tubing pickup for any given set of conditions. Also presented in their paper is a graphical solution of the same formula.

A further simplified method of solution is presented herein in chart form for 2-3/8 inch, 2-7/8 inch, and 3-1/2 inch O.D. EU or NU API tubing in Figs. 9, 10, and 11, respectively. In the development of these charts, a fluid gradient of 0.5 psi/ft. was used since it represents a salt water gradient and therefore the probable maximum fluid gradient in any pumping well. The chart solution then gives a tubing pickup that is correct only for a well producing 100 per cent salt water and is slightly greater than required for wells producing clean oil. However, since insufficient tension may be quite harmful whereas slightly excess tension has no detrimental effects, and also since the required fluid level and fluid gradient data are rarely known accurately, it would seem that this method of solution, which tends to provide a margin of safety, is justifiable.

Basis For Charts

Referring to Figs. 9, 10, and 11, it can be seen that there is a series of three charts identified as "F_1", "F_2" and "F_3" for each tubing size. "F_1" is a chart of tabulated values for "Operating Fluid Level vs. Depth of Pump and Tubing Anchor." (It is assumed that the tubing anchor will be installed immediately adjacent to the pump in the tubing string, as this is the anchor location required for the complete elimination of tubing buckling and breathing). "F_3" is a similar chart for "Fluid Level at the Time Anchor is Set vs. Depth of Pump and Tubing Anchor," while the "F_2" chart gives the pickup required for various values of "Temperature of Pumped Fluid at the Surface minus the Mean Yearly Temperature" for the area in which the well is located. (See "Explanation of Temperature Effect" later in the Appendix).

The "F_1" chart values were calculated from that

TABLES FOR COMPUTING FORCE AGAINST TUBING ANCHOR

(2⅜" O.D. EU OR NU A.P.I. TUBING)

TABLE I — "F_1"

FOR 2-3/8 OD EU OR NU API TUBING

(WELL FLUID - SALT WATER)

Rows: DEPTH OF PUMP AND TUBING ANCHOR - FEET. Columns: OPERATING FLUID LEVEL - FEET.

Depth	250	500	750	1000	1250	1500	1750	2000	2250	2500	2750	3000	3250	3500	3750	4000	4250	4500	4750	5000
1000	250	610	1030	1550																
1500	240	550	910	1330	1800	2330														
2000	240	520	850	1220	1630	2080	2570	3100												
2500	230	510	810	1160	1530	1930	2360	2830	3330	3870										
3000	230	500	780	1110	1460	1830	2230	2660	3110	3590	4100	4640								
3500	230	490	770	1080	1410	1760	2130	2530	2950	3400	3860	4360	4880	5420						
4000	230	480	750	1060	1370	1700	2060	2430	2830	3250	3690	4140	4630	5130	5650	6300				
4500	230	480	740	1040	1340	1660	2000	2360	2740	3130	3550	3980	4440	4910	5390	5900	6430	6970		
5000	230	470	730	1020	1310	1630	1960	2300	2660	3040	3430	3840	4280	4730	5190	5670	6160	6670	7200	7750
5500	230	470	730	1010	1300	1600	1920	2250	2600	2960	3340	3740	4160	4580	5020	5470	5940	6420	6930	7450
6000	230	470	720	1000	1280	1580	1890	2210	2550	2900	3270	3650	4050	4450	4880	5310	5760	6220	6700	7200
6500	230	470	720	990	1270	1560	1860	2190	2510	2850	3200	3570	3960	4350	4760	5180	5610	6050	6510	6980
7000	230	460	710	980	1260	1540	1840	2150	2470	2800	3150	3500	3880	4260	4650	5060	5480	5900	6340	6800
7500	230	460	710	980	1250	1530	1820	2120	2440	2760	3100	3450	3820	4180	4560	4960	5360	5770	6200	6640
8000	220	460	710	970	1240	1520	1800	2100	2410	2730	3060	3400	3760	4120	4490	4870	5260	5660	6070	6510
8500	220	460	700	970	1230	1510	1790	2080	2390	2700	3020	3350	3710	4060	4420	4790	5170	5560	5960	6380
9000	220	460	700	960	1220	1500	1780	2060	2360	2670	2990	3310	3660	4010	4360	4720	5090	5470	5870	6270
9500	220	460	700	960	1210	1490	1770	2050	2340	2650	2960	3280	3620	3960	4300	4660	5020	5400	5780	6180
10000	220	460	700	960	1200	1480	1760	2040	2330	2630	2930	3250	3580	3910	4250	4600	4960	5320	5700	6090

Depth	5250	5500	5750	6000	6250	6500	6750	7000	7250	7500	7750	8000	8250	8500	8750	9000	9250	9500	9750	10000
5500	7980	8520																		
6000	7700	8210	8750	9300																
6500	7470	7960	8460	8990	9520	10070														
7000	7270	7740	8220	8730	9230	9760	10300	10850												
7500	7090	7550	8010	8500	8990	9490	10010	10540	11070	11620										
8000	6940	7380	7830	8300	8770	9260	9760	10270	10790	11310	11840	12390								
8500	6800	7230	7670	8120	8580	9050	9540	10030	10530	11030	11550	12080	12610	13170						
9000	6690	7100	7530	7970	8410	8870	9340	9820	10300	10790	11290	11800	12320	12850	13390	13940				
9500	6580	6980	7400	7830	8260	8700	9170	9630	10100	10570	11060	11550	12050	12570	13090	13630	14160	14700		
10000	6480	6870	7280	7700	8120	8550	9000	9450	9920	10370	10850	11330	11820	12320	12820	13350	13860	14400	14930	15490

TABLE II — "F_2"

FOR 2-3/8 OD EU OR NU API TUBING

To obtain figure at right, subtract Mean Yearly Temperature* from Temperature of Well Fluid at Surface. (°F)	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
"F_2"	1350	2700	4050	5400	6750	8100	9450	10800	12150	13500	14850	16200	17550	18900	20200	21600	22900	24300	25600	27000

* Mean Yearly Temperature for area in which well is located -- Mid-Continent 60° F -- Gulf Coast 70° F, as taken from Lubinski's paper Buckling of Tubing in Pumping Wells, Its Effects and Means for Controlling It.

TABLE III — "F_3"

FOR 2-3/8 OD EU OR NU API TUBING

(WELL FLUID - SALT WATER)

Rows: DEPTH OF PUMP AND TUBING ANCHOR - FEET. Columns: FLUID LEVEL AT TIME ANCHOR IS SET - FEET.

Depth	250	500	750	1000	1250	1500	1750	2000	2250	2500	2750	3000	3250	3500	3750	4000	4250	4500	4750	5000
1000	80	180	310	460																
1500	80	160	270	390	530	680														
2000	80	150	260	360	480	610	760	910												
2500	70	150	240	340	450	570	700	830	990	1140										
3000	70	150	240	330	430	540	660	780	920	1060	1210	1370								
3500	70	140	230	320	420	520	630	740	870	1000	1140	1280	1440	1600						
4000	70	140	230	310	410	500	610	720	840	960	1090	1220	1370	1510	1670	1820				
4500	70	140	220	300	400	490	590	690	810	920	1050	1170	1310	1440	1590	1740	1900	2050		
5000	70	140	220	300	390	480	580	680	790	890	1020	1130	1260	1390	1530	1670	1820	1960	2120	2290
5500	70	140	220	300	390	470	570	660	770	870	990	1090	1230	1350	1480	1610	1750	1890	2040	2200
6000	70	140	220	290	380	460	560	650	750	850	970	1070	1190	1310	1440	1560	1700	1830	1980	2130
6500	70	140	220	290	380	460	550	640	740	830	950	1050	1170	1280	1400	1520	1650	1780	1920	2060
7000	70	140	220	290	370	450	560	630	730	820	930	1030	1150	1250	1380	1490	1610	1740	1870	2010
7500	70	140	210	290	370	450	540	620	720	810	910	1010	1130	1230	1350	1460	1580	1700	1830	1960
8000	70	140	210	280	370	450	540	620	710	800	900	1000	1110	1210	1320	1430	1550	1670	1790	1920
8500	70	140	210	280	370	440	530	610	700	790	890	990	1090	1190	1300	1410	1530	1640	1760	1890
9000	70	140	210	280	360	440	530	610	700	780	880	980	1080	1170	1280	1390	1500	1610	1730	1850
9500	70	140	210	280	360	440	520	600	690	770	870	970	1070	1160	1270	1370	1480	1590	1700	1820
10000	70	130	210	280	360	430	520	600	690	770	870	960	1060	1150	1260	1350	1460	1570	1680	1800

Depth	5250	5500	5750	6000	6250	6500	6750	7000	7250	7500	7750	8000	8250	8500	8750	9000	9250	9500	9750	10000
5500	2350	2520																		
6000	2270	2430	2580	2740																
6500	2200	2350	2500	2650	2810	2970														
7000	2140	2290	2420	2580	2720	2880	3030	3200												
7500	2090	2230	2360	2510	2650	2800	2950	3110	3260	3430										
8000	2040	2180	2310	2450	2590	2730	2870	3030	3180	3340	3490	3660								
8500	2000	2140	2260	2400	2530	2670	2810	2960	3100	3260	3400	3560	3720	3880						
9000	1970	2100	2220	2350	2480	2620	2750	2900	3030	3180	3320	3480	3630	3790	3940	4110				
9500	1940	2060	2180	2310	2430	2570	2700	2840	2970	3120	3260	3410	3550	3710	3860	4020	4170	4340		
10000	1910	2030	2150	2270	2390	2530	2650	2790	2920	3060	3200	3340	3480	3630	3780	3930	4080	4250	4400	4570

Figure 9

TABLES FOR COMPUTING FORCE AGAINST TUBING ANCHOR

(2⅞" O.D. EU OR NU A.P.I. TUBING)

TABLE IV — "F_1"

FOR 2-7/8 OD EU OR NU API TUBING

(WELL FLUID - SALT WATER)

Rows: DEPTH OF PUMP AND TUBING ANCHOR - FEET; columns: OPERATING FLUID LEVEL - FEET

Depth	250	500	750	1000	1250	1500	1750	2000	2250	2500	2750	3000
1000	380	890	1520	2180								
1500	360	810	1340	1950	2640	3400						
2000	350	770	1240	1790	2380	3040	3760	4540				
2500	340	750	1190	1690	2230	2820	3460	4150	4890	5670		
3000	340	730	1150	1630	2130	2670	3270	3890	4560	5270	6010	6800
3500	340	720	1130	1580	2060	2570	3120	3700	4330	4980	5660	6380
4000	340	710	1110	1540	2000	2490	3020	3560	4150	4760	5400	6070
4500	330	700	1090	1520	1960	2430	2930	3450	4020	4590	5200	5830
5000	330	700	1080	1500	1920	2380	2870	3370	3910	4460	5030	5630
5500	330	690	1070	1480	1900	2340	2810	3300	3820	4350	4900	5470
6000	330	690	1060	1460	1870	2310	2770	3240	3740	4250	4790	5340
6500	330	690	1050	1450	1850	2280	2730	3190	3680	4180	4690	5230
7000	330	680	1050	1440	1840	2250	2700	3150	3620	4110	4610	5130
7500	330	680	1040	1430	1820	2230	2670	3110	3580	4050	4540	5050
8000	330	680	1040	1420	1810	2210	2640	3080	3540	4000	4480	4980
8500	330	680	1030	1410	1800	2200	2620	3050	3500	3960	4430	4910
9000	330	680	1030	1410	1790	2180	2600	3020	3470	3920	4380	4850
9500	330	680	1030	1400	1780	2170	2580	3000	3440	3880	4340	4800
10000	330	670	1030	1400	1770	2160	2570	2980	3410	3850	4300	4760

Depth	3250	3500	3750	4000	4250	4500	4750	5000	5250	5500	5750	6000	6250	6500
3500	7160	7950												
4000	6790	7520	8290	9090										
4500	6510	7190	7910	8660	9400	10210								
5000	6280	6930	7600	8310	9010	9770	10550	11350						
5500	6090	6710	7350	8020	8690	9410	10150	10910	11690	12480				
6000	5940	6530	7150	7790	8340	9110	9820	10530	11280	12040	12830	13630		
6500	5800	6380	6970	7580	8200	8860	9540	10220	10930	11660	12410	13180	13960	14770
7000	5690	6240	6820	7410	8010	8640	9290	9960	10640	11340	12060	12790	13540	14320
7500	5590	6130	6690	7270	7840	8460	9080	9730	10380	11060	11750	12460	13180	13920
8000	5510	6030	6570	7130	7690	8300	8900	9520	10160	10810	11480	12160	12860	13580
8500	5430	5940	6470	7020	7570	8150	8740	9340	9960	10600	11240	11900	12580	13270
9000	5360	5870	6380	6920	7450	8020	8590	9180	9780	10400	11030	11680	12330	13000
9500	5300	5800	6300	6830	7350	7900	8460	9040	9630	10230	10840	11470	12110	12760
10000	5250	5730	6230	6740	7260	7800	8350	8910	9490	10080	10670	11290	11910	12550

Depth	6750	7000	7250	7500	7750	8000	8250	8500	8750	9000	9250	9500	9750	10000
7000	15100	15890												
7500	14680	15440	16230	17020										
8000	14300	15040	15810	16560	17350	18170								
8500	13970	14690	15430	16160	16920	17720	18500	19280						
9000	13690	14370	15100	15800	16540	17300	18070	18820	19630	20420				
9500	13430	14090	14800	15480	16200	16940	17680	18410	19190	19910	20750	21550		
10000	13190	13800	14520	15190	15890	16610	17330	18040	18800	19550	20310	21090	21880	22710

TABLE V — "F_2"

FOR 2-7/8 OD EU OR NU API TUBING

To obtain figure at right, subtract Mean Yearly Temperature* from Temperature of Well Fluid at Surface. (°F)	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
"F_2"	1880	3750	5630	7500	9370	11250	13100	15000	16900	18800	20600	22500	24400	26100	28100	30000	31800	33700	35600	37500

* Mean Yearly Temperature for area in which well is located -- Mid-Continent 60° F -- Gulf Coast 70° F, as taken from Lubinski's paper Buckling of Tubing in Pumping Wells, Its Effects and Means for Controlling It.

TABLE VI — "F_3"

FOR 2-7/8 OD EU OR NU API TUBING

(WELL FLUID - SALT WATER)

Rows: DEPTH OF PUMP AND TUBING ANCHOR - FEET; columns: FLUID LEVEL AT TIME ANCHOR IS SET - FEET

Depth	250	500	750	1000	1250	1500	1750	2000	2250	2500	2750	3000
1000	110	250	420	630								
1500	100	230	370	540	730	950						
2000	100	210	350	500	660	850	1050	1260				
2500	100	210	330	470	620	780	960	1160	1360	1580		
3000	100	200	320	450	590	740	910	1080	1270	1470	1680	1910
3500	90	200	310	440	570	710	870	1030	1200	1390	1590	1790
4000	90	200	310	430	560	690	840	990	1150	1330	1510	1700
4500	90	200	300	420	540	680	820	960	1120	1280	1460	1630
5000	90	190	300	410	530	660	800	940	1090	1240	1410	1580
5500	90	190	300	410	530	650	780	920	1060	1210	1370	1530
6000	90	190	300	410	520	640	770	900	1040	1180	1340	1500
6500	90	190	290	400	520	630	760	890	1020	1160	1320	1470
7000	90	190	290	400	510	630	750	880	1010	1140	1290	1440
7500	90	190	290	400	510	620	740	870	990	1130	1270	1420
8000	90	190	290	390	500	620	730	860	980	1110	1260	1400
8500	90	190	290	390	500	610	730	850	970	1100	1240	1380
9000	90	190	290	390	500	610	720	840	960	1090	1230	1360
9500	90	190	290	390	490	600	720	830	950	1080	1220	1350
10000	90	190	290	390	490	600	710	830	940	1070	1210	1330

Depth	3250	3500	3750	4000	4250	4500	4750	5000	5250	5500	5750	6000	6250	6500
3500	2000	2220												
4000	1900	2100	2310	2540										
4500	1820	2010	2210	2420	2630	2850								
5000	1750	1940	2120	2320	2520	2730	2950	3170						
5500	1700	1880	2060	2240	2430	2630	2840	3040	3260	3490				
6000	1660	1830	2000	2170	2360	2550	2740	2940	3150	3360	3580	3800		
6500	1620	1780	1950	2120	2290	2480	2660	2850	3050	3250	3460	3680	3890	4120
7000	1590	1750	1910	2070	2240	2420	2600	2780	2970	3160	3360	3570	3780	3990
7500	1560	1710	1870	2030	2190	2360	2540	2710	2900	3090	3280	3480	3680	3880
8000	1540	1690	1840	1990	2150	2320	2490	2660	2840	3020	3200	3390	3590	3790
8500	1520	1660	1810	1960	2120	2280	2440	2610	2780	2960	3140	3320	3510	3700
9000	1500	1640	1780	1930	2090	2240	2400	2560	2730	2900	3080	3260	3440	3630
9500	1480	1620	1760	1900	2060	2210	2370	2520	2690	2850	3030	3200	3380	3560
10000	1470	1600	1740	1880	2030	2180	2330	2490	2650	2810	2980	3150	3320	3500

Depth	6750	7000	7250	7500	7750	8000	8250	8500	8750	9000	9250	9500	9750	10000
7000	4220	4440												
7500	4100	4320	4540	4760										
8000	4000	4210	4420	4630	4850	5070								
8500	3910	4110	4310	4520	4730	4940	5170	5390						
9000	3820	4020	4220	4420	4620	4830	5040	5260	5470	5700				
9500	3750	3940	4130	4330	4530	4730	4940	5150	5350	5580	5800	6020		
10000	3690	3870	4060	4250	4440	4640	4840	5040	5240	5460	5680	5890	6120	6340

Figure 10

TABLES FOR COMPUTING FORCE AGAINST TUBING ANCHOR

(3½" O.D. EU OR NU A.P.I. TUBING)

TABLE VII — "F_1"

FOR 3-1/2 OD EU OR NU API TUBING

(WELL FLUID - SALT WATER)

DEPTH OF PUMP AND TUBING ANCHOR - FEET

	250	500	750	1000	1250	1500	1750	2000	2250	2500	2750	3000	3250	3500	3750	4000	4250	4500	4750	5000	5250	5500	5750	6000	6250	6500	6750	7000	7250	7500	7750	8000	8250	8500	8750	9000	9250	9500	9750	10000
1000	570	1320	2250	3360																																				
1500	540	1200	1980	2880	3900	5040																																		
2000	530	1140	1850	2640	3520	4500	5200	6690																																
2500	520	1100	1760	2500	3300	4170	4830	6120	7230	8400																														
3000	510	1080	1710	2400	3150	3960	4580	5740	6750	7800	8910	10080																												
3500	510	1060	1670	2330	3040	3800	4410	5460	6400	7370	8390	9460	10590	11760																										
4000	500	1050	1640	2280	2960	3690	4280	5260	6140	7050	8000	9000	10040	11120	12260	13440																								
4500	500	1040	1620	2240	2900	3600	4180	5100	5940	6800	7700	8640	9620	10640	11700	12800	13930	15120																						
5000	500	1030	1600	2210	2850	3530	4100	4970	5780	6600	7460	8350	9280	10250	11250	12290	13350	14470	15440	16800																				
5500	500	1030	1590	2180	2810	3470	4030	4870	5640	6440	7260	8100	9010	9920	10880	11870	12880	13940	14860	16140	17280	18460																		
6000	500	1020	1580	2160	2770	3420	3970	4780	5530	6300	7100	7920	8770	9660	10570	11520	12480	13500	14390	15600	16690	17800	18960	20150																
6500	490	1020	1570	2140	2740	3380	3920	4710	5440	6190	6960	7760	8580	9430	10320	11230	12150	13130	13980	15140	16180	17250	18350	19480	20650	21840														
7000	490	1010	1560	2120	2720	3340	3880	4640	5360	6090	6840	7610	8410	9240	10090	10970	11860	12810	13630	14740	15750	16770	17830	18820	20040	21170	22330	23520												
7500	490	1010	1550	2110	2700	3310	3850	4590	5290	6000	6730	7490	8270	9070	9900	10750	11620	12530	13330	14400	15360	16350	17380	18420	19500	20590	21710	22840	24020	25200										
8000	490	1010	1540	2100	2680	3280	3820	4540	5230	5930	6640	7380	8140	8920	9730	10560	11400	12290	13070	14100	15030	15990	16980	17990	19030	20080	21160	22250	23380	24520	25680	26860								
8500	490	1000	1530	2090	2660	3260	3790	4500	5180	5860	6560	7290	8030	8790	9580	10390	11210	12070	12830	13830	14740	15670	16630	17610	18620	19640	20680	21730	22820	23930	25040	26180	27360	28580						
9000	490	1000	1530	2080	2650	3240	3770	4460	5130	5800	6490	7200	7930	8680	9450	10240	11040	11880	12630	13600	14490	15390	16320	17270	18250	19240	20250	21270	22320	23400	24480	25580	26720	27890	29030	30230				
9500	490	1000	1520	2070	2640	3220	3750	4430	5090	5750	6430	7120	7840	8580	9330	10110	10890	11710	12440	13390	14250	15130	16040	16970	17920	18880	19860	20860	21880	22920	23980	25050	26140	27280	28400	29560	30720	31930		
10000	490	1000	1520	2060	2630	3200	3730	4400	5050	5700	6370	7060	7760	8480	9220	9980	10750	11560	12280	13200	14040	14910	15790	16690	17620	18560	19520	20490	21480	22500	23520	24560	25640	27740	27820	28940	30060	31240	32400	33600

OPERATING FLUID LEVEL - FEET

TABLE VIII — "F_2"

FOR 3-1/2 OD EU OR NU API TUBING

To obtain figure at right, subtract Mean Yearly Temperature* from Temperature of Well Fluid at Surface. (°F)	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
"F_2"	2680	5360	8040	10720	13400	16080	18760	21440	24120	26800	29480	32160	34840	37520	40200	42880	45560	48240	50920	53600

* Mean Yearly Temperature for area in which well is located -- Mid-Continent 60° F -- Gulf Coast 70° F. as taken from Lubinski and Blenkarn's paper Buckling of Tubing in Pumping Wells, Its Effects and Means for Controlling It.

TABLE IX — "F_3"

FOR 3-1/2 OD EU OR NU API TUBING

(WELL FLUID - SALT WATER)

DEPTH OF PUMP AND TUBING ANCHOR - FEET

	250	500	750	1000	1250	1500	1750	2000	2250	2500	2750	3000	3250	3500	3750	4000	4250	4500	4750	5000	5250	5500	5750	6000	6250	6500	6750	7000	7250	7500	7750	8000	8250	8500	8750	9000	9250	9500	9750	10000
1000	150	360	610	910																																				
1500	150	320	540	780	1060	1360																																		
2000	140	310	500	710	950	1220	1510	1820																																
2500	140	300	480	680	890	1130	1390	1660	1960	2270																														
3000	140	290	460	650	850	1070	1310	1560	1830	2110	2400	2720																												
3500	140	290	450	630	820	1030	1250	1480	1730	1990	2260	2550	2850	3170																										
4000	140	280	440	620	800	1000	1210	1430	1660	1910	2160	2430	2710	3000	3310	3630																								
4500	140	280	440	610	780	970	1170	1390	1610	1840	2070	2330	2590	2870	3150	3450	3760	4080																						
5000	130	280	430	600	770	950	1150	1350	1570	1790	2010	2250	2500	2760	3030	3310	3600	3900	4220	4530																				
5500	130	280	430	590	760	940	1130	1320	1530	1740	1950	2190	2430	2680	2930	3200	3480	3760	4060	4360	4670	4990																		
6000	130	280	430	580	750	930	1110	1300	1500	1700	1910	2130	2360	2600	2860	3110	3370	3640	3920	4210	4510	4810	5120	5440																
6500	130	270	420	580	740	920	1090	1280	1470	1670	1870	2090	2310	2540	2780	3030	3280	3540	3810	4090	4370	4660	4960	5260	5580	5900														
7000	130	270	420	580	740	910	1080	1260	1450	1640	1840	2050	2270	2490	2720	2960	3200	3450	3710	3980	4250	4530	4820	5110	5410	5720	6030	6360												
7500	130	270	420	570	730	900	1070	1240	1430	1620	1810	2020	2230	2450	2690	2900	3140	3380	3630	3890	4150	4420	4700	4980	5270	5560	5870	6170	6490	6810										
8000	130	270	420	570	730	890	1060	1230	1410	1600	1790	1990	2190	2410	2620	2850	3080	3310	3560	3800	4060	4320	4590	4860	5140	5420	5720	6020	6310	6620	6940	7260								
8500	130	270	420	570	720	880	1050	1220	1400	1580	1770	1960	2160	2370	2580	2800	3030	3250	3490	3730	3980	4230	4490	4760	5030	5300	5590	5880	6160	6460	6770	7120	7390	7710						
9000	130	270	410	560	720	880	1040	1210	1390	1560	1750	1940	2130	2340	2550	2760	2980	3200	3430	3670	3910	4160	4410	4670	4930	5200	5470	5750	6030	6320	6620	6920	7220	7530	7850	8160				
9500	130	270	410	560	710	870	1030	1200	1380	1550	1730	1920	2110	2310	2520	2720	2940	3150	3380	3610	3850	4090	4330	4590	4840	5100	5370	5640	5910	6190	6480	6770	7070	7370	7670	7970	8300	8610		
10000	130	270	410	560	710	870	1030	1190	1370	1540	1710	1900	2090	2290	2490	2690	2900	3110	3340	3560	3790	4030	4270	4510	4760	5010	5280	5540	5800	6080	6360	6640	6930	7220	7520	7810	8120	8430	8740	9070

FLUID LEVEL AT TIME ANCHOR IS SET - FEET

Figure 11

portion of the complete formula which deals with the operating fluid level. The "F_2" and "F_3" charts were calculated similarly, using the portions of the formula that take into account the temperature factor and the fluid level at the time the anchor is set, respectively.

The calculation of the pickup that corrects for casing gas pressure during pumping was neglected in the preparation of these charts since, in actual practice, the value of that term is so small, in relation to the other terms, that it is insignificant.

Use Of Charts

To arrive at the required pickup in pounds to be applied to the tubing, the three forces "F_1", "F_2" and "F_3" are picked from the charts for the size tubing involved. Then "F_1" and "F_2" are added together, and from that total "F_3" is subtracted. This gives the total force or pickup required, which may be designated as "F_t". Expressed as a formula, the combination of "F_1", "F_2" and "F_3" becomes:

$$F_t = F_1 + F_2 - F_3$$

The following example illustrates the procedure to be followed in using the charts.

Tubing Size - - - - - - - - - - - - - - - 2-3/8 OD EU
Depth of Pump and Tubing Anchor - - - - 6,000 feet
Fluid Level at Time Anchor is Set - - - 4,000 feet
Operating Fluid Level - - - - - - - - - - - 6,000 feet
Fluid Temperature at Surface - - - - - - - - 100°F
Mean Yearly Temperature for Area in
which well is located - - - - - - - - - - - - 60°F

From Fig. 9 for 2-3/8 inch O.D. EU or NU Tubing:

F_1 = 9,300 pounds
F_2 = 5,400 pounds
F_3 = 1,560 pounds

$F_t = F_1 + F_2 - F_3$

= 9,300 pounds + 5,400 pounds - 1,560 pounds

= <u>13,140 pounds pickup to be applied</u>

In the case of an automatic or compensating tubing anchor, the same F_t or total force as calculated above will exist after pumping is stopped and the fluid in the tubing drains to equalization with the annulus fluid level.

Selection Of Proper Shear Strength Emergency Release

It is mentioned in this paper that tension type tubing anchors are generally equipped with some emergency release feature; usually some member that will shear when a predetermined amount of pull is taken against the anchor. The shear members are provided in several strengths for each anchor. Obviously, the strength of the shear member must be greater than F_t calculated above, or it will fail and release the anchor the first time pumping is stopped. The tubing anchor manufacturer's recommended safety margin should be allowed between the calculated F_t and the strength of the shear member to provide for well data inaccuracies and manufacturing tolerances of the shear member.

Required Tubing Strength For Tension Type Anchors

After the required tubing pickup and strength of shear member for an anchor is established, it is absolutely essential to find out whether the tensile strength of the tubing upon which the anchor will be run is adequate for the particular situation in question.

Minimum Hook Load For Emergency Release

The minimum hook load (weight indicator reading) to cause an emergency release shear member to fail is the sum of the weight of the tubing string plus the force required to part the shear member. Since the fluid level may be very near the bottom of the tubing string in some wells, it is always safest to use the weight of the tubing string in air; that is, disregard buoyancy in the calculations. For example: With a 6,000 foot string of 2-7/8 inch O.D. external upset tubing (which weighs approximately 6.50 pounds per foot in air) and a 30,000 pound shear member in the tubing anchor, the minimum hook load to part the shear member would then be 6,000 feet x 6.5 pounds per foot or 39,000 pounds of tubing plus 30,000 pounds to part the shear member for a total hook load of 69,000 pounds to affect an emergency release of the anchor.

Maximum Hook Load For Emergency Release

The foregoing method of calculation for the hook load to part the shear member is applicable for the majority of cases wherein the standing valve, which retains the fluid in the tubing, and the sucker rod string are retrieved during routine well pulling. However, under certain conditions the hook load to part the shear member may be appreciably greater. If the sucker rods are pulled but the standing valve cannot be retrieved, a fluid load would esist in the tubing which would also have to be supported in parting the shear member. Further, if the sucker rod string is parted in one of the top rods and cannot be fished out because of a sanded up pump plunger, then the weight of the rods would also have to be supported in order to part the shear member. The sum total to these loads represents the worst possible condition that could be encountered in relation to tubing tensile strength.

To summarize, the maximum possible hook load or load on the top joint of the tubing string in parting a shear member in any type of tension tubing anchor would consist of:

Weight of the tubing string in air	________
plus, force to part the shear member	________
plus, weight of sucker rod string in air	________
plus, weight of the fluid inside the tubing	________
TOTAL	========

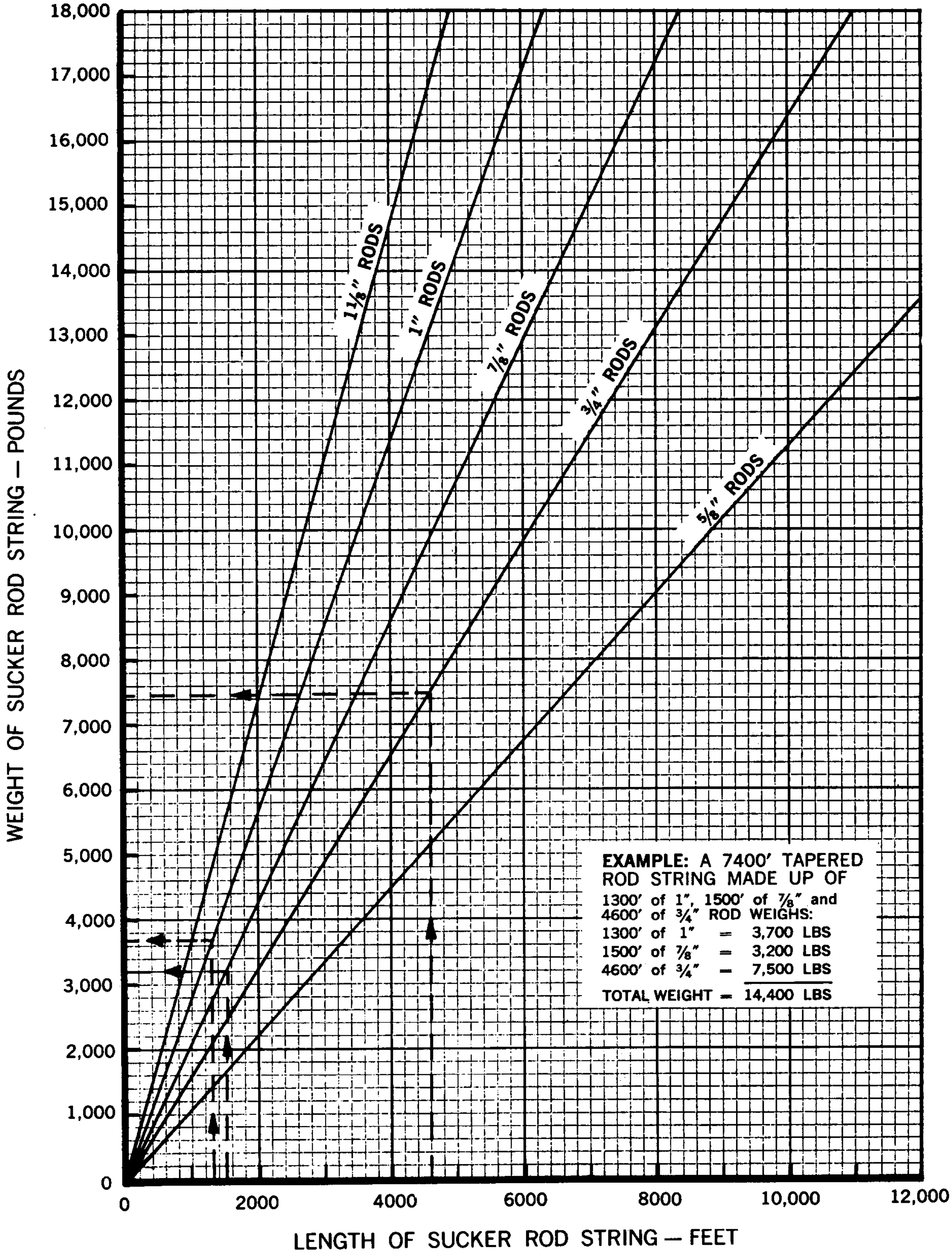
The values to be used for these four factors can be determined as follows:

Weight Of Tubing String In Air

Multiply the weight per foot of tubing in air by the total length in feet.

Force To Part Shear Member

The strength of the shear member is recommended by the tubing anchor manufacturer and is based upon the maximum force that will exist against the anchor. (See "F_t" under previous section "Use of Charts").



WEIGHT OF SUCKER ROD STRING IN AIR

Figure 12

Weight Of Sucker Rod String In Air

Reference to the attached Fig. 12 provides a convenient means of determining the weight of the rod string.

Weight Of The Fluid Inside The Tubing

The weight of the fluid in the tubing can be found by referring to the attached Figs. 13 and 14. (Fluid

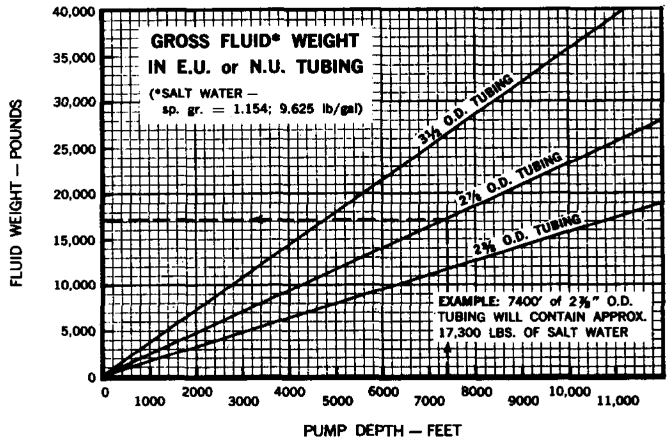


Fig. 13

is assumed to be salt water since many wells produce high percentages of that fluid.) Fig. 13 gives the weight of salt water that is contained in up to 12,000 feet of 2-3/8 inch, 2-7/8 inch and 3-1/2 inch O.D. API tubing. This chart is labeled "Gross Fluid Weight" since it shows the total weight of fluid the tubing could contain. However, part of that fluid will be displaced by the sucker rods. Since the weight of the rod string will have already been determined, Fig. 14 was prepared to show the weight of fluid that is displaced by the pounds of steel in the rod string. Therefore, the "Weight of Fluid Inside the Tubing" used in the calculation of the hook load to part the shear member is gross fluid weight from Fig. 13 minus the fluid displaced by sucker rods from Fig. 14.

The following example will serve to illustrate the preceding discussion:

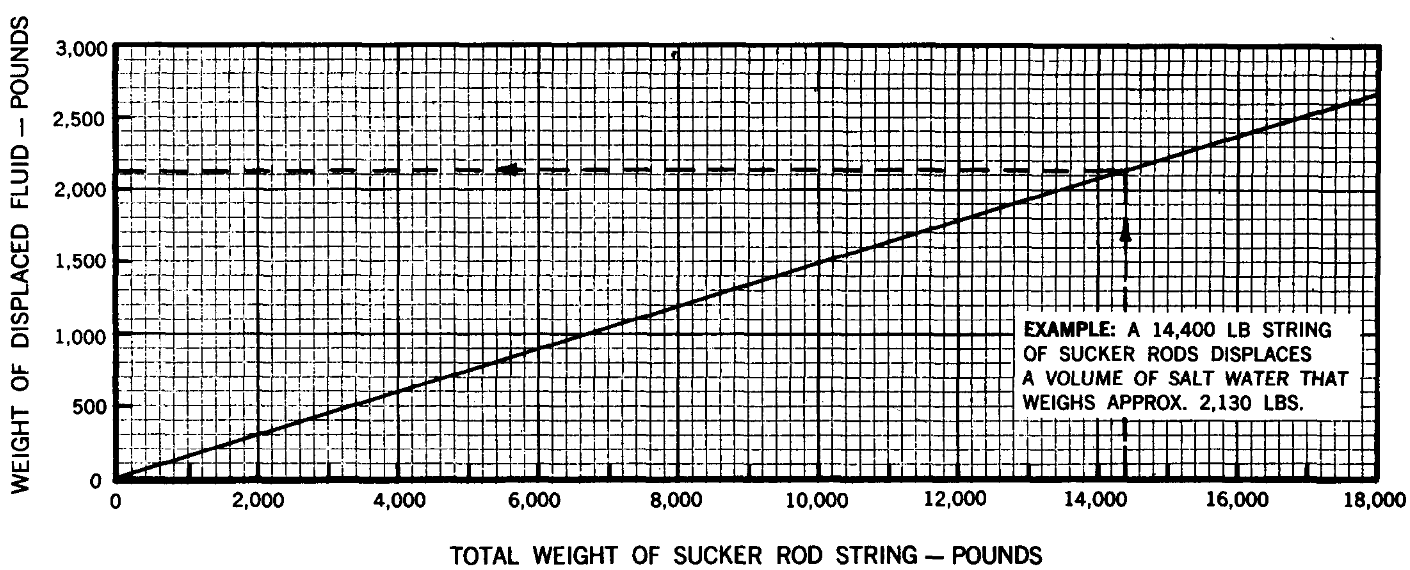
Given:

a) 7400 feet of 2-7/8 inch O.D. EU tubing
b) Pump located at bottom of tubing string
c) 30,000 pound shear member
d) 7400' sucker rod string made of: 1300' of 1" rods
1500' of 7/8" rods
4600' of 3/4" rods

Weight of tubing string (7400'x6.5#/ft.	48,100#
plus, force to part shear member (given)	30,000#
plus, weight of sucker rod string (See example, Fig. 12)	14,400#
plus, weight of fluid in tubing (See examples, Figs. 13 & 14; 17,300# minus 2,130#)	15,170#
Maximum Possible Hook Load For Emergency Release	= 107,670#

To be absolutely safe, it then follows that the strength of the top portion of the tubing string should be in excess of 107,670 pounds.

Should the strength of that portion of the tubing string in this case be less than 107,670 pounds, it does not necessarily mean that it would be unsafe to run a tension type tubing anchor which has a 30,000 pound shear



WEIGHT OF TUBING FLUID* DISPLACED BY SUCKER RODS

(*SALT WATER — sp. gr. = 1.154; 9.625 LB/GAL)

Fig. 14

member in it. Many pumping wells in which it is desired to install a tension type tubing anchor will have a well established production history, or if not in that particular well, the operating history of nearby wells producing from the same pay zone may suffice.

If the rods and standing valve are always retrievable, the hook load to affect emergency release that must be considered in relation to the tubing strength is merely the sum of the weight of the tubing string plus the force to part the shear member, or 78,100 pounds in this example. If the rods can always be retrieved, but occasionally difficulty is encountered in retrieving the standing valve, then possibly the fluid load should be added; and the strength of the tubing would have to be in excess of 93,270 pounds (48,100 pounds for tubing plus 30,000 pounds for the shear member plus 15,170 pounds of fluid). This is pointed out to illustrate that a certain amount of personal judgement must be used in working out tubing anchor installations rather than relying solely on formulas and charts.

If the tubing string in this example were 2-7/8 inch O.D. EU N-80 tubing in good condition, which has a listed minimum yield strength of 144,960 pounds, then it would be perfectly safe to run the tubing anchor with the 30,000 pound shear member in it since there would be a calculated minimum margin of safety of 37,290 pounds (tubing strength of 144,960 pounds minus calculated maximum hook load of 107,670 pounds). However, if the tubing string in this case were 2-7/8 inch O.D. EU J-55 tubing which has a listed minimum yield strength of only 99,660 pounds, in order to be able to pull the full 107,670 pound hook load to part the shear member, an upper portion of the J-55 tubing string would have to be replaced with N-80 tubing.

Amount Of Higher Grade Tubing Required

In order to be able to better understand the method of determining just how much J-55 tubing would have to be replaced with N-80 tubing, the forces involved in determining the maximum hook load to part the shear member of the anchor should again be reviewed. Those forces are the weight of the sucker rod string (assuming that a rod in the top part of the string fails and the string cannot be fished out), the weight of the fluid in the tubing (if the rods cannot be fished out, the standing valve cannot be retrieved to drain the tubing), the force to part the shear member and the weight of the string of tubing.

Since the combined weights of the parted rod string and the fluid load are supported on the bottom of the tubing string, these two forces can be assumed to be weights hanging on the bottom of the tubing string. Similarly, the force to part the shear member can also be considered as a weight hanging on the bottom of the tubing string.

Therefore, the tensile load on the tubing one joint up from the anchor at the moment the shear member parts is the sum of the rod load, the fluid load, the shear member load, and the weight of the one joint of tubing. In the example given for illustration purposes this would be 59,765 pounds (14,400 pounds of rods, plus 15,120 pounds of fluid, plus 30,000 pounds to part the shear member, plus 195 pounds for one joint of tubing). In considering various points higher up in the tubing string, it is seen that the tensile load exerted at the moment the shear member parts, increases from the 59,765 pound value one joint up from the tubing anchor to the 107,670 pound value for the top joint of tubing at the rate of 6.5 pounds per foot.

It follows, therefore, that at some point up the tubing string from the anchor, a tensile load of 99,660 pounds would exist at the moment the shear member parts, and from that point on up to the top of the tubing string the tensile load would be in excess of the tubing strength. It is this upper portion of the J-55 tubing string that would have to be replaced with N-80 tubing. The minimum amount that must be replaced is equal to 107,670 pounds (the maximum hook load to be imposed) minus 99,660 pounds (the tubing strength) or 8,010 pounds of tubing. In terms of length it would be, in this case, 8,010 pounds divided by 6.5 pounds per foot or 1232 feet of N-80 required for the top portion of the tubing string. This again is the minimum amount of N-80 required.

Under these conditions the top joint of J-55 tubing would have a 99,660 pound tensile load at the moment the shear member parts and, consequently, no margin of safety. If a 10,000 pound margin of safety is desired (89,660 pound tensile load on the top joint of J-55 tubing at the moment the shear member parts), then the same method just outlined for determining the required amount of N-80 tubing is used, except that the calculations would be 107,670 minus 89,660 or 18,010 pounds which is equivalent to 2771 feet of N-80 required. (Refer to Fig. 16 for an example of this type of problem.)

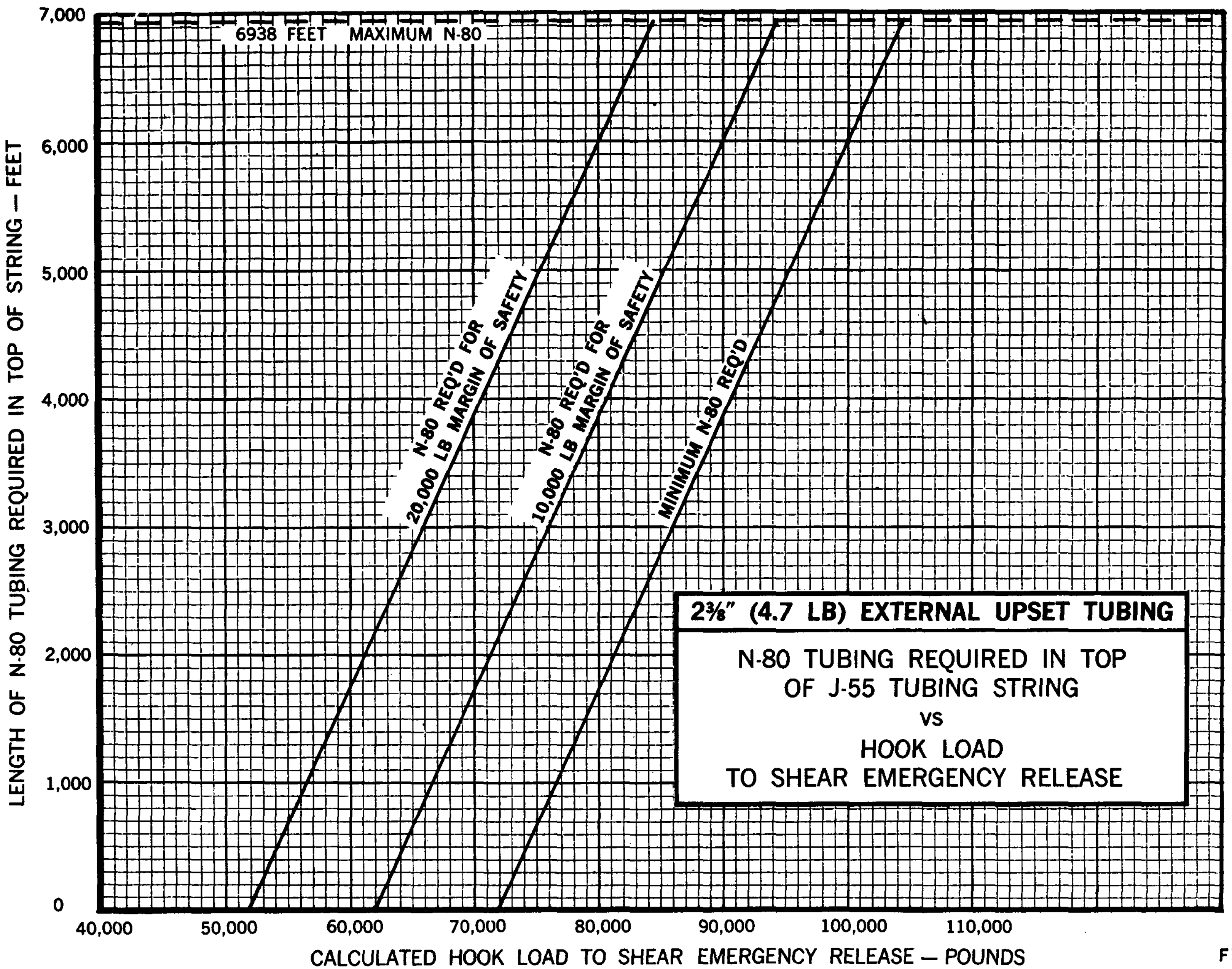
NOTE: A margin of safety should always be allowed for additional hook load that may be required to part the shear member because of tubing friction in deviated well bores.

This detailed explanation has been given in an attempt to develop a complete understanding of the forces involved and how they apply to the tubing string. Once the situation is completely understood, the method outlined above can be applied to any tubing string encountered, regardless of the various sizes and grades of tubing of which it is composed. Figs. 15, 16, and 17 provide a simple graphical means of determining the proper amount of EU N-80 tubing to be used for the top portions of 2-3/8 inch, 2-7/8 inch and 3-1/2 inch OD EU grade J-55 tubing strings when the calculated hook load to affect emergency release of a tubing anchor exceeds the strength of the tubing in question. These charts were developed in accordance with the foregoing discussion.

Explanation Of Temperature Effect

Generally speaking, down hole temperature increases rather uniformly with depth at any given location, although the rate of temperature increase with depth varies considerably from area to area. Fortunately, for the purpose of properly setting a tubing anchor, a knowledge of down hole temperatures is not necessary. Only the temperature of the pumped fluid at the well head, and the mean or average yearly temperature for the area in which the well is located are required. Both are readily obtainable if not already known.

Reference to Fig. 18 will clarify the reasoning for the preceding statements. (It must be understood that the temperature values shown in Fig. 18 are for illustrative purposes only. Letters or other identifying symbols are generally preferred to numerical values, but they sometimes confuse those not accustomed to that type of illustration.)



6938 FEET MAXIMUM N-80
N-80 REQ'D FOR 20,000 LB MARGIN OF SAFETY
N-80 REQ'D FOR 10,000 LB MARGIN OF SAFETY
MINIMUM N-80 REQ'D
2⅜" (4.7 LB) EXTERNAL UPSET TUBING
N-80 TUBING REQUIRED IN TOP OF J-55 TUBING STRING
VS
HOOK LOAD TO SHEAR EMERGENCY RELEASE
LENGTH OF N-80 TUBING REQUIRED IN TOP OF STRING — FEET
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
40,000
50,000
60,000
70,000
80,000
90,000
100,000
110,000
CALCULATED HOOK LOAD TO SHEAR EMERGENCY RELEASE — POUNDS

Figure 15

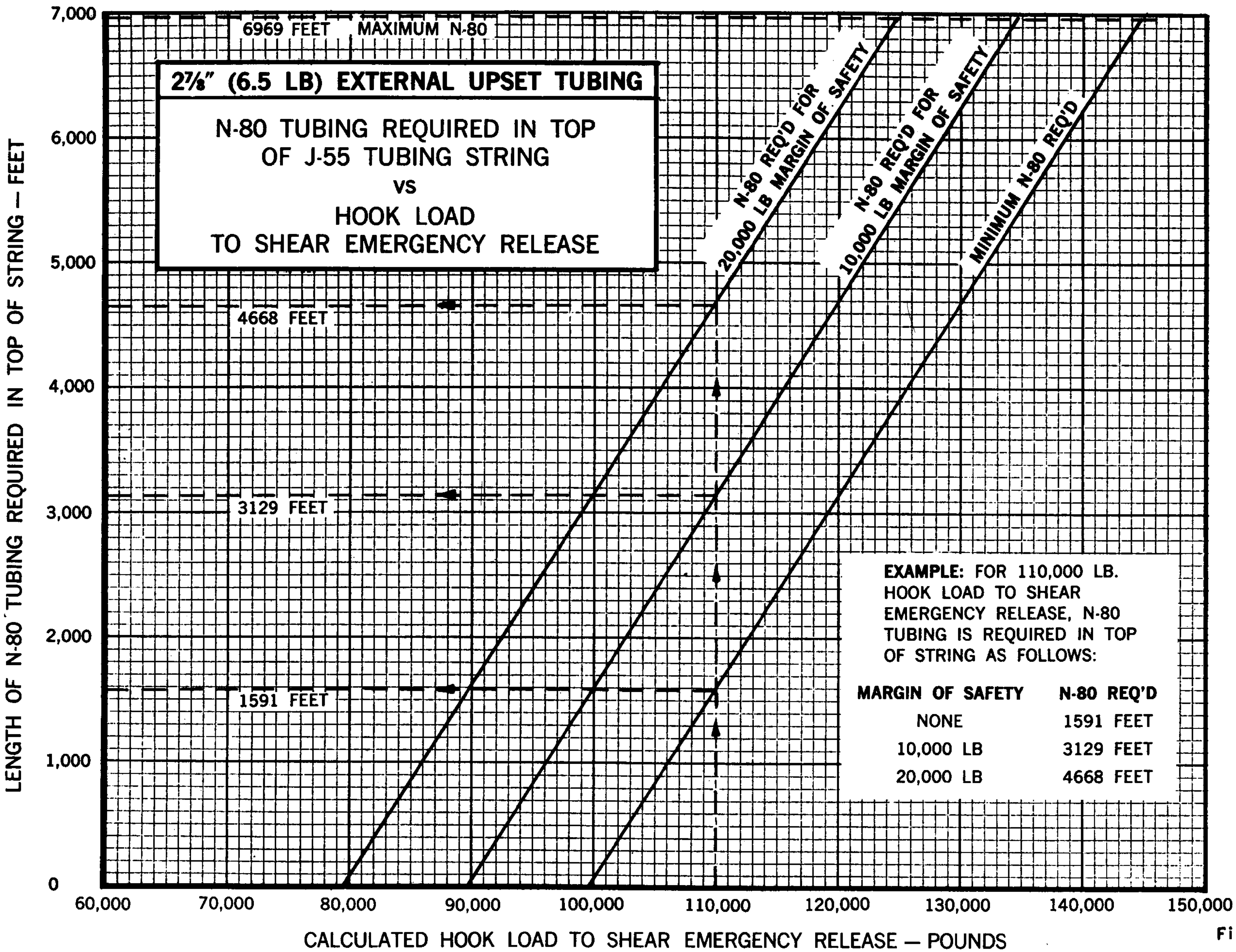

2⅞" (6.5 LB) EXTERNAL UPSET TUBING
N-80 TUBING REQUIRED IN TOP OF J-55 TUBING STRING vs HOOK LOAD TO SHEAR EMERGENCY RELEASE
6969 FEET MAXIMUM N-80
4668 FEET
3129 FEET
1591 FEET
20,000 LB MARGIN OF SAFETY N-80 REQ'D FOR
10,000 LB MARGIN OF SAFETY N-80 REQ'D FOR
MINIMUM N-80 REQ'D
EXAMPLE: FOR 110,000 LB. HOOK LOAD TO SHEAR EMERGENCY RELEASE, N-80 TUBING IS REQUIRED IN TOP OF STRING AS FOLLOWS:
MARGIN OF SAFETY N-80 REQ'D
NONE 1591 FEET
10,000 LB 3129 FEET
20,000 LB 4668 FEET
LENGTH OF N-80 TUBING REQUIRED IN TOP OF STRING — FEET
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
60,000
70,000
80,000
90,000
100,000
110,000
120,000
130,000
140,000
150,000
CALCULATED HOOK LOAD TO SHEAR EMERGENCY RELEASE — POUNDS

Figure 16

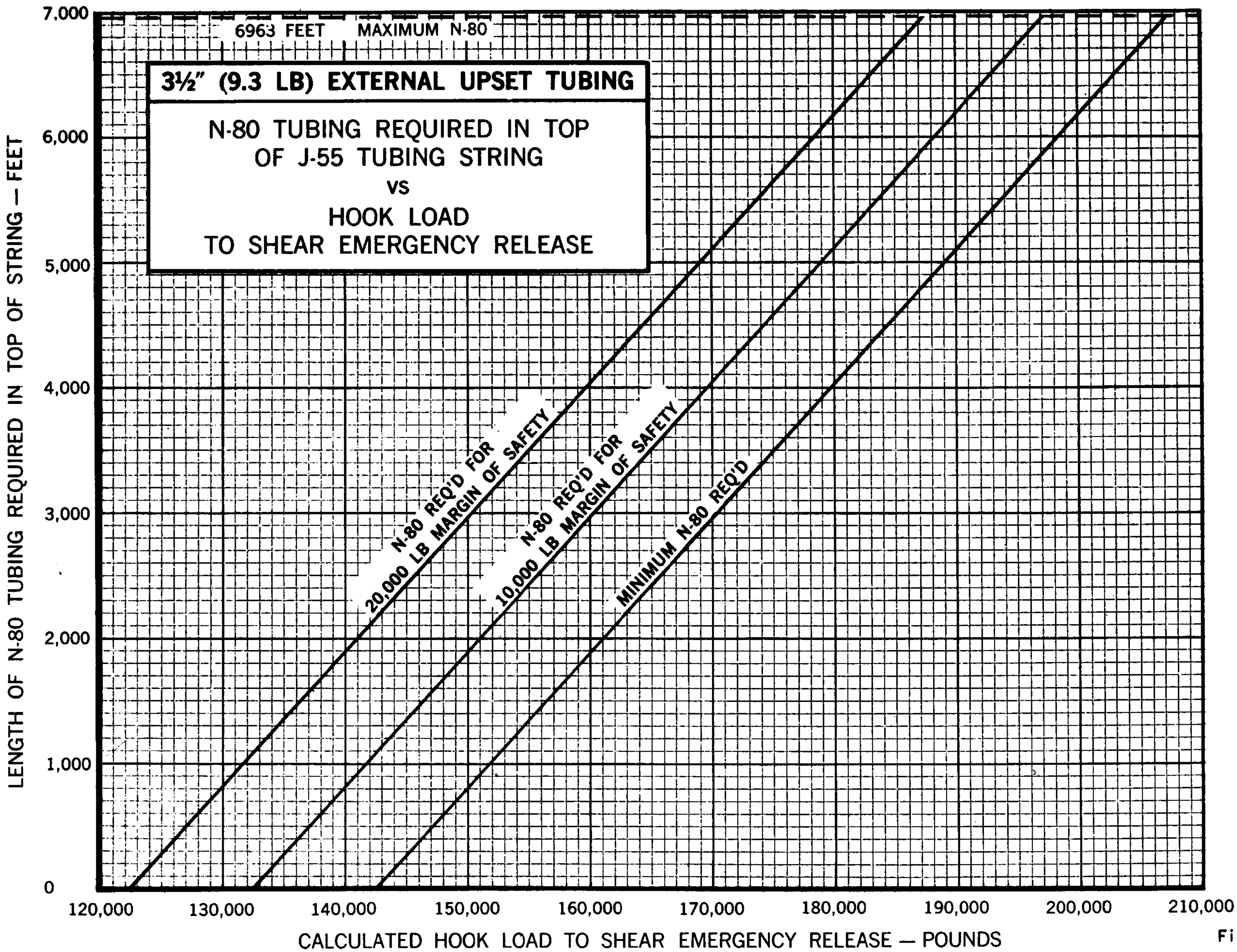

6963 FEET MAXIMUM N-80
3½" (9.3 LB) EXTERNAL UPSET TUBING
N-80 TUBING REQUIRED IN TOP
OF J-55 TUBING STRING
vs
HOOK LOAD
TO SHEAR EMERGENCY RELEASE
N-80 REQ'D FOR 20,000 LB MARGIN OF SAFETY
N-80 REQ'D FOR 10,000 LB MARGIN OF SAFETY
MINIMUM N-80 REQ'D
LENGTH OF N-80 TUBING REQUIRED IN TOP OF STRING — FEET
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
120,000
130,000
140,000
150,000
160,000
170,000
180,000
190,000
200,000
210,000
CALCULATED HOOK LOAD TO SHEAR EMERGENCY RELEASE — POUNDS

Figure 17

The down hole temperature at the depth of the anchor is shown to be 180°F, and the line connecting that point with the 60°F surface temperature simulates the plot of a temperature survey of a well when it is not being produced; in other words, it represents the static temperature gradient. The deviation from the static temperature gradient at the very top portion of the hole, as shown by the dashed lines to 40°F and to 80°F, represents the influence of seasonal temperature changes, which are effective for only a few feet below the surface and are, therefore, of negligible importance. The 60°F temperature is the mean yearly temperature for the area in which the well is located.

Before pumping is started, the temperature of the tubing at any depth is assumed to be the same as the temperature of the formation at that depth; hence, the formation static temperature gradient is also the static temperature gradient of the tubing. Although the raising of the temperature of the tubing from surface temperature to formation temperature when it is run in the well causes some elongation, it has no bearing on the problem of anchoring the tubing since that elongation undoubtedly will have occurred before the anchor is set. When the well is producing, the relatively hot fluid being lifted raises the temperature of the tubing string and causes elongation after the tubing anchor is set. This is the thermal elongation which must be considered in order to set a tubing anchor properly.

Again referring to Fig. 18, if the well were produced at an infinitely low rate, it can be assumed that the fluid would lose all of its heat to the surrounding formations on its way up and would arrive at the surface at 60°F, so the temperature of the tubing string would not be changed. On the other extreme, if the well were produced at an infinitely high rate, the fluid would arrive at the surface at essentially bottom hole temperature, as shown by the 180°F constant temperature line from anchor depth to surface, and the tubing would undergo a maximum increase in temperature. Actually the tubing temperature gradient in a producing well would be somewhere between the two extremes, as depicted by the line which shows the fluid arriving at the surface at a temperature of 120°F.

In this example then, the temperature of the top joint of tubing increases from 60°F to 120°F when the well is put on production. That temperature increase is shown as ΔT in Fig. 1. The temperature of each succeeding lower joint of tubing increases by progressively lesser amounts until, at the bottom of the string, there is no increase in temperature. Therefore, since the temperature increase over the length of the tubing string gradually diminishes from a maximum of 60°F at the top to no increase at the bottom, the average temperature increase of the entire tubing string is one-half of 60°F or 30°F. Simply stated, the average temperature increase of the entire tubing string is one-half the difference between the temperature of the pumped fluid at the well head and the mean yearly temperature for the area in which the well is located.

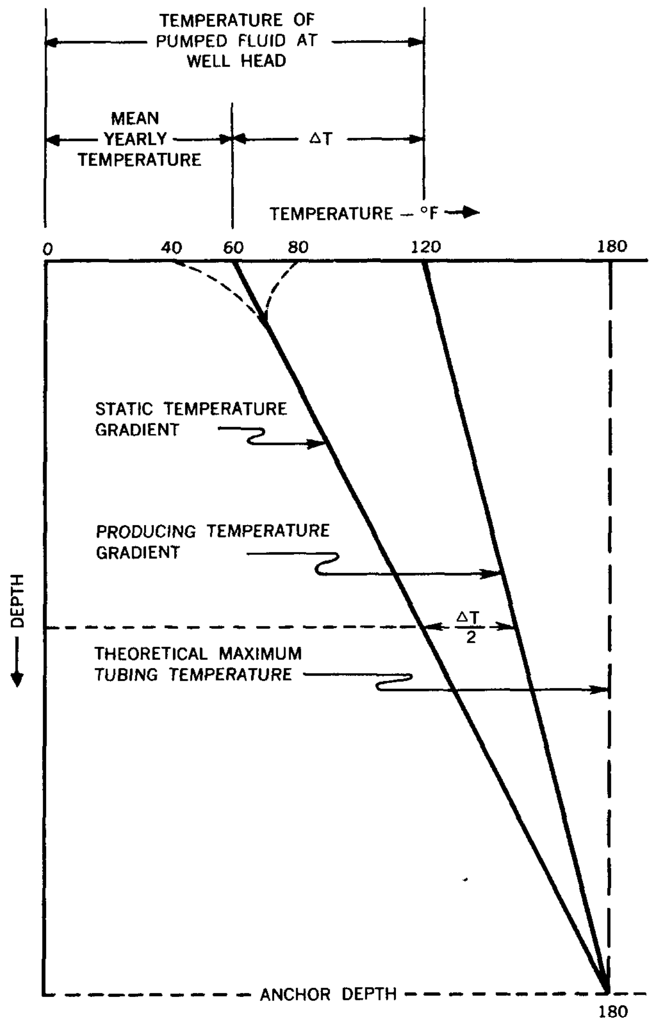


Fig. 18