Tubingless Completions

By ROBERT A. KENT
Baker Oil Tools, Inc.

ABSTRACT

As the result of a rapidly expanding backlog of experience and knowledge, more and more operators are viewing tubingless completions as a practical and entirely feasible means of completing wells.

Fundamentally, of course, the basic reason for employing tubing as casing is to reduce the initial capital investment required for the completion of a well. The factor of economic savings is considerably broader in scope than might first be realized by those who have not yet had actual experience with tubingless completions. For instance, in some cases, otherwise uneconomical wells can be completed for a reasonable profit. Further in exploratory wells, where it is sometimes found that production prospects on the basis of existing evaluation methods of techniques are questionable, operators can give much more serious consideration to setting casing for actual extended production tests of one or more potential pay zones complete with stimulation treatments if desired.

However, as all operators know, much more than casing is required to complete and produce a well. Equipment manufacturers have found that providing the required equipment to meet the challenge of very small diameter casing is much more complex than is merely miniaturizing their existing well established products. However, the challenge has been met with outstanding success as evidenced by the ever-increasing popularity and acceptance of the tubingless completion method.

It is the purpose of this paper to present a discussion of some of the basic equipment and newly developed techniques that have substantially contributed to the success of tubingless completions.

INTRODUCTION

The term "tubingless completion" is now widely accepted as a means of designating any well completed with very small diameter pipe as casing: the most widely used casing in these completions is standard 2 7/8 in. OD API tubing. This terminology in itself lends a certain amount of confusion to those who might not yet be familiar with this relatively new technique for completing wells. In accepted oilfield terminology, the term "tubing" usually signifies small diameter pipe that is run inside casing to serve as a conductor for the produced fluid or gas. Now, even though "tubing" is used for tubingless completions and still often functions as the produced fluid or gas conductor, since there is no outer string of pipe between it and the well bore, from a functional standpoint, the 2 7/8 in. OD tubing then becomes casing and the well is considered to be tubingless.

COST REDUCTIONS OBTAINED BY TUBINGLESS COMPLETIONS IN 1959

ITEM	CHANGE	APPROX. SAVINGS	APPROX SAVINGS IN A 3000 ft. WELL
SURFACE CASING	8 5/8 → 7	$120/100 ft	$480
OIL STRING	5 1/2 → 2 7/8	$90/100 ft	$2700
TUBING STRING	2 3/8 → NONE	$73/100 ft	$2190
WELL HEAD	8 5/8 x 5 1/2 x 2 3/8 → 7 x 2 7/8	$1400	$1400
		TOTAL	$6770

Fig. 1

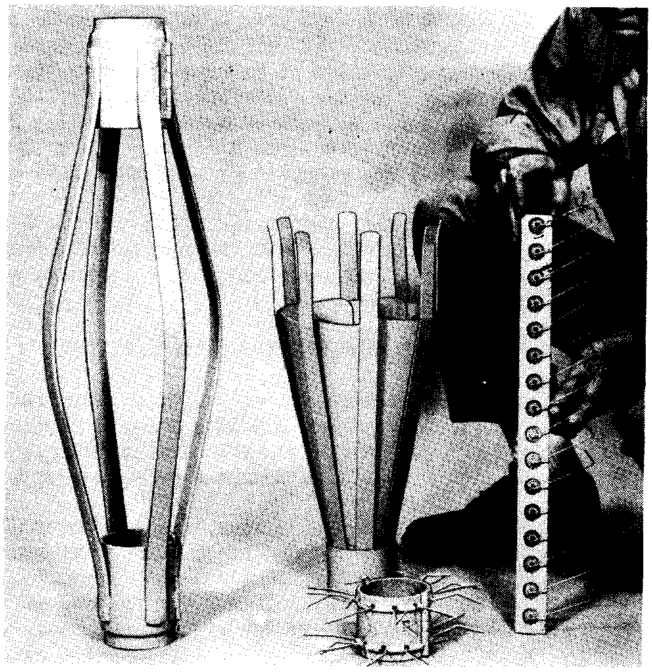

Fig. 2 Centralizer, Basket and Scratchers

In its earliest concept, a tubingless completion was just that — a completion in which 2 7/8 in. tubing was cemented in open hole as casing and in which no inner string of tubing was used for production. However, as the success of this completion method has lead to its becoming more widely exploited, it has been found advantageous in many instances to have a smaller diameter tubing string inside the 2 7/8 in. casing for the same general reasons why tubing is employed in more conventially sized wells. In spite of the fact that a large percentage of the so-called tubingless completions now incorporate an inner tubing string and, therefore, are not actually tubingless, but in fact are miniaturized or scaled-down versions of their larger "standard" counterparts, the initially applied terminology persists.

Many multiple tubingless completions have been and are being made in which two or more strings of tubing are run parallel and cemented in the bore hole for the purpose of exploiting multiple pay zones. The major difference between these multiple completions and multiple completions employing parallel tubing strings and packers in casing is that, in the tubingless variety, the conventional casing string has been eliminated; yet the wells are still designated "tubingless" when it would seem that the term "casingless" might be more appropriate.

In recent years, there has been a trend toward slimhole conventional type completions wherein 4 1/2 in. or

5 in. casing is used. Then came the big jump downward to 2 7/8 in. OD casing and the term "tubingless completion" evolved. Although the success of tubingless completions has been quite pronounced, there are limitations resulting from this rather drastic miniaturization, which probably accounts for an apparent increase in interest in some areas in the completions utilizing casing sizes that bridge the gap between "slim-hole" completions and "tubingless" completions. Therefore, the original connotation in reference to size that delineated slim-hole completions and tubingless completions may tend to become obscured. It would appear, however, that possibly the term tubingless completion will still be applied to any completion using for casing a size pipe that has, through long acceptance, been classified as tubing.

The term "tubingless completion" will be used in this paper in a general sense to indicate both miniaturized completions and true tubingless completions in which no inner tubing string is employed.

ECONOMICS OF TUBINGLESS COMPLETIONS

Numerous examples have appeared in the various trade and technical journals which illustrate possible savings that may be realized through the utilization of tubingless completions.[1, 2, 3, 4] An illustration of one such example is shown in Fig. 1.

Each specific situation, of course, requires an individual analysis to determine the relative economic aspects of tubingless completions versus conventional completions, for completion practices vary markedly from area to area and are based on field requirement

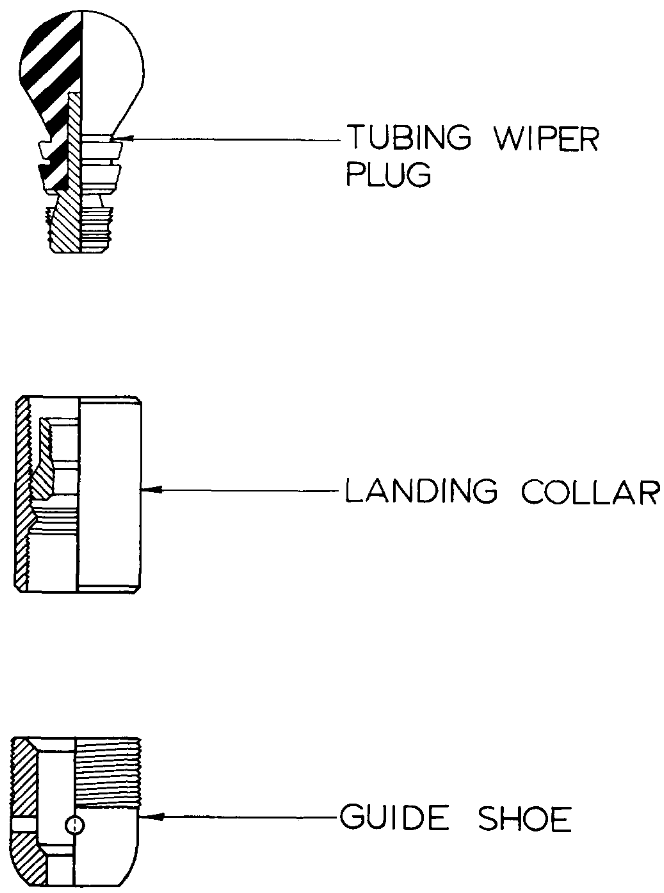

Fig. 4 Cementing Plug, Collar and Shoe

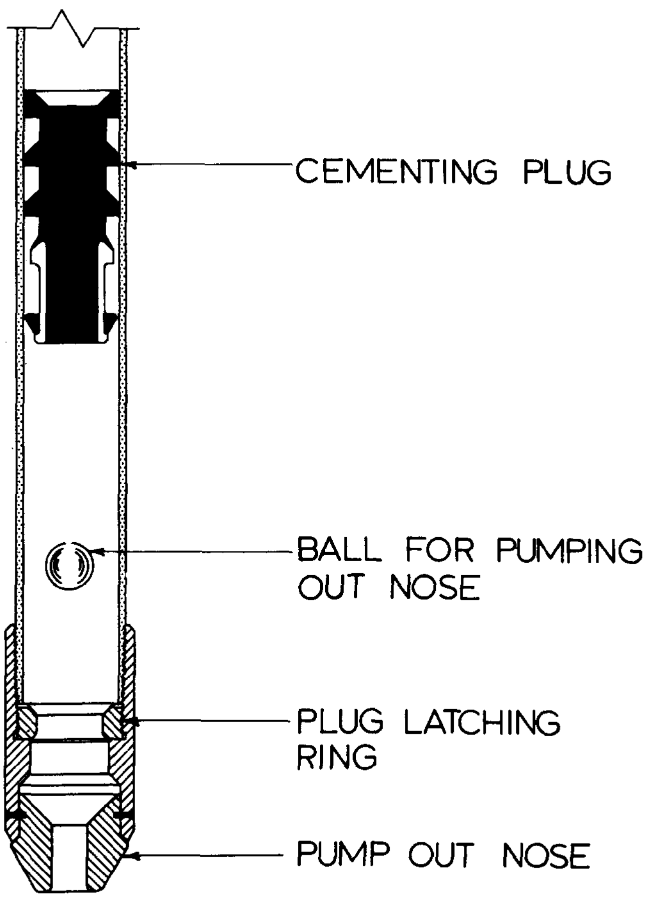

Fig. 3 Guide Shoe with Pump-Out Nose

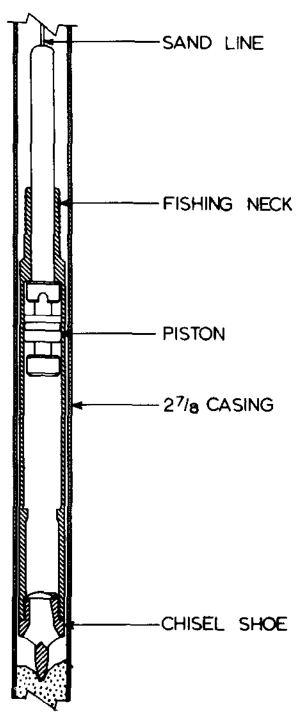

Fig. 5 Drilling-Type Sand Pump

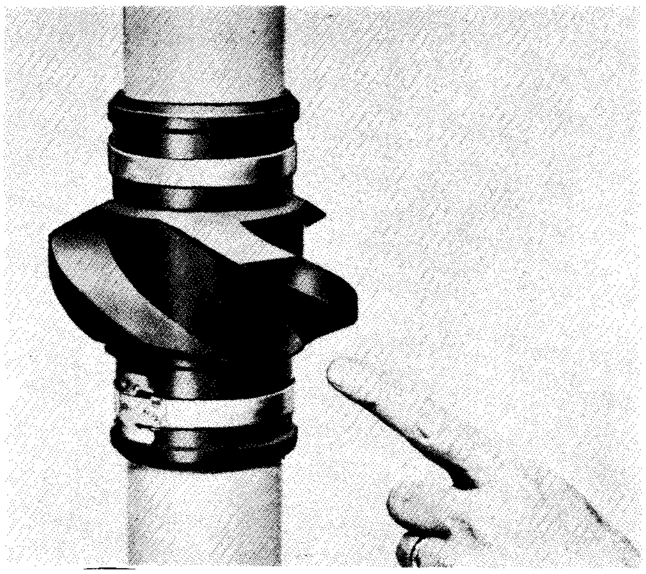

Fig. 6 5 5/8" Turbulizer

as well as operators' preference. Where slim-hole practices are already employed, tubingless completions would obviously offer a smaller economic savings than in those areas where larger size casings are generally used. Various other factors such as the amount of fluid produced, type of production, artificial lift requirements, possible remedial or work-over requirements and corrosion or mechanical problems must also be considered in the over-all analysis. Generally speaking, many operators have realized sufficiently attractive savings from experience already gained with tubingless completions to cause them to review all development work planned for the future with the idea of employing wherever possible tubingless completions.

Initially, the primary objective of the tubingless completion method was the reduction, by eliminating the outer casing string, of initial capital investment required for well completions. As a side effect, the bore hole size could also be reduced, but the elimination of the outer casing string is the most obvious direct cost reduction when considering tubingless completions; however, in studying the complete picture, there are other interesting factors which also enhance the attractiveness of tubingless completions. For example, shortening the pay-out time can be an important consideration, especially under the stress of tightly restricted production allowables. Too, there can even be instances where the reduction in initial capital investment will make it possible to drill and complete wells that might not otherwise be economically feasible.

Multiple tubingless completions have offered increased profits in another way in areas where pay zone permeability is highly susceptible to damage. In the course of completion or work-over operations, it may be necessary to kill one or more upper zones to work on lower zones, and as a result, the productivity of the killed zones is sometimes seriously impaired. However, cementing a tubing string in the well bore for each pay zone permits each zone to be treated as if it were being produced by an individual well; therefore, operations performed in any one pay zone in no way affect the other pay zones.

In the course of drilling and evaluating exploratory wells, there are occasional cases where existing evaluation methods or techniques still leave some doubt about the commercial possibilities of a potential pay zone. This doubt exists particularly in those instances where stimulation treatments are required before true production potential is revealed. In a case such as this, a decision must be made as to whether the expense involved in running casing for a test is justified. The much lower cost of, for example, 2 7/8 in. OD casing relieves much of the burden of such a decision.

There are also other factors. Some of these factors are now known and some will undoubtedly be learned through future experience, but they reveal or will reveal other ways in which tubingless completions can result in additional net profit.

FUTURE COST REDUCTIONS

It does not seem at all unlikely that the attractiveness of the present-day cost of tubingless completions over that of conventional completions in terms of drilling, completing, and producing will become even more pronounced in the future. Now, lower cost, lightweight, highly portable drilling rigs, tailored specifically for slimhole drilling offer a definite means of reducing costs for both operators and drilling contractors.[5]

And, in the future, still further cost reductions will be realized on completion of development work now being done by bit companies on smaller bits that will produce a more realistic bore hole size for single strings of small diameter casing. For example, at the present time, the majority of holes drilled for wells to be cased with a single string of 2 7/8 in. OD casing are drilled with bits ranging in size from 6 1/8 in. to 6 3/4 in. because bit life with respect to teeth and bearings in these sizes is better than bit life is with smaller sizes.[6] With smaller bits, direct savings should be realized not

Fig. 7 Drillable Bridge Plug

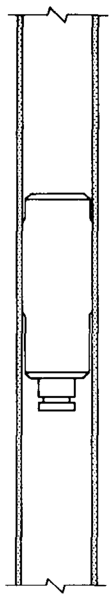

Fig. 8 Expansion Cylinder Type Plug

only because of the lesser amount of material that has to be excavated but also because of the reduction in the amount of drilling mud and cement required.

When operators began to experiment with tubingless completions, they naturally wanted to utilize standard, well established techniques and procedures for completing and producing their wells. Equipment manufacturers were, therefore, suddenly called on to duplicate major portions of their product lines in miniature sizes. Some down-hole equipment could, with little difficulty, be reduced in size but for the majority of items either an entirely new or at least modified approach had to be taken. The design and development of new equipment is, in itself, very costly and this cost is particularly high where there is only a limited demand for the developed products.

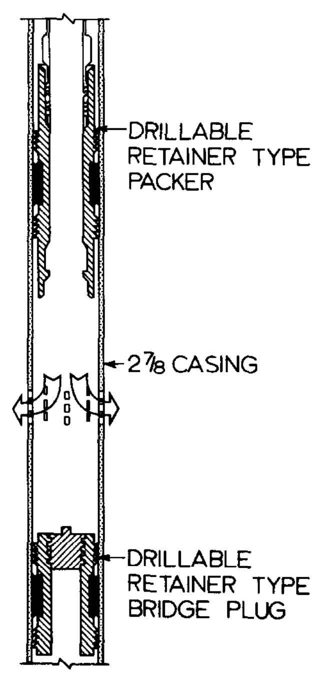

Fig. 10 Treating with Drillable Tools

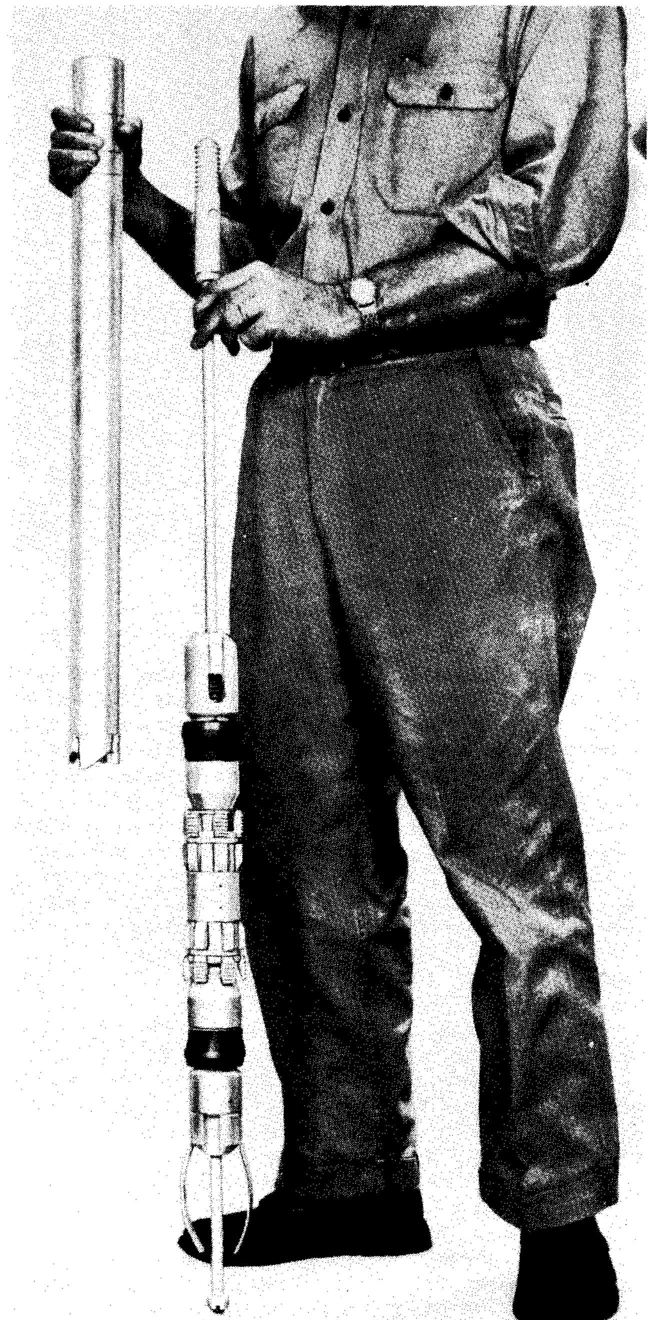

Fig. 9 Retrievable Bridge Plug

Since tubingless completed wells still comprise only a small percentage of the total number of wells drilled and, furthermore, since they are generally drilled in place of rather than in addition to normally planned standard sized wells, equipment manufacturers must, in effect, substitute limited quantity items of equipment for high quantity items that are manufactured under efficient, highly organized mass production systems and methods. However, with the present-day increasing demand for greater quantities of small size tools and equipment, it is inevitable that there will be some resulting decrease in manufacturing costs which will be reflected by lower prices.

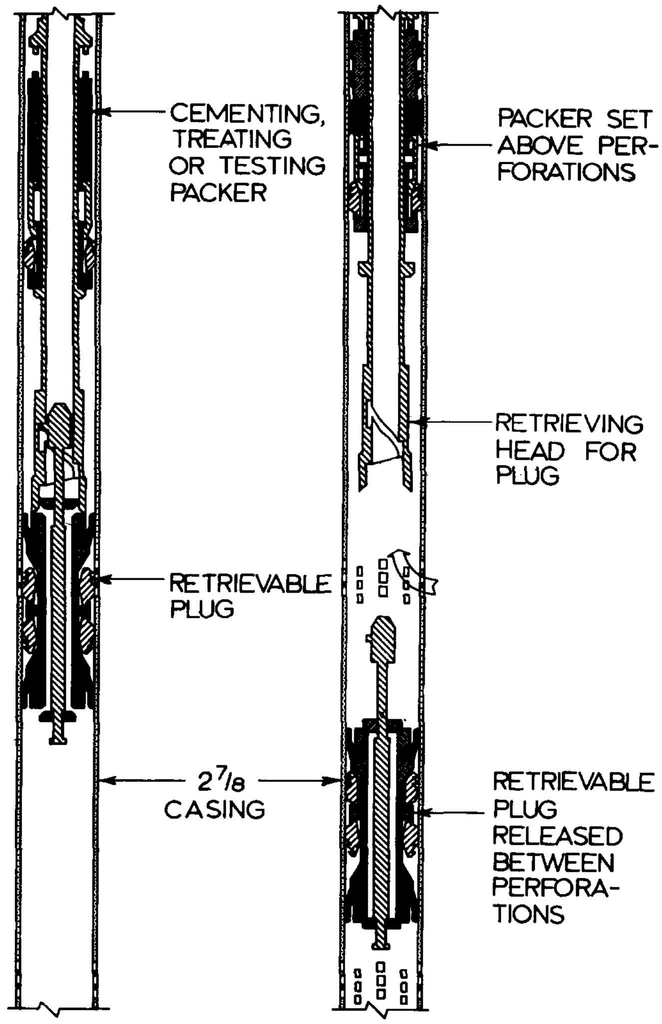

Fig. 11 Treating with Retrievable Tools

Equipment Design Considerations

In the cases of a few items of down-hole equipment for single string tubingless completions such as scratchers and centralizers, the reduction in size to make them compatible with 2 7/8 in. casing does not present any particular problem (Fig. 2). However, for the majority of items, a serious reduction in size does present problems. For example, in the case of primary cementing equipment, since displacement rates will logically be lower due to friction loss and, further, since annulus clearances will generally be abnormally large, any appreciable restriction in cementing shoes should be eliminated.[5] Flow-over problems during running of small diameter casing are virtually non-existent so the basic purpose of back pressure or float valves is merely to prevent back flow of displaced cement. These conditions have lead to the development of such features as pump-out noses in guide shoes and latching type cementing plugs that function as back pressure valves (Figs. 3 and 4).

Further, Stage Cementing Collars have been designed that depart from the conventional plug actuated method used in larger sizes of casing because of the problem of passing cementing plugs through restricted inside diameters.

The drillability of the various components of permanent (non-retrievable) type packers, cement retainers, bridge plugs, and other such equipment, has to be carefully considered because of the problems inherent with the small diameter drilling strings and bits that can be run inside 2-7/8 in. OD casing. Various types of milling tools have been and are being developed which seem to offer the best solution to many of these drilling problems. Wire line operated sand pumps have also been developed to successfully cope with some drilling problems in 2 7/8 in. OD casing (Fig. 5).

Wherever possible, there have been devised equipment and techniques that eliminate or minimize drilling-out problems. For example, guide shoe noses that can be pumped out have already been mentioned. Furthermore, operators frequently follow the practice of making some over-hole and running casing to bottom thereby eliminating the necessity of drilling out the cement in the shoe joint. Also surplus casing may serve as a junk catcher for it is frequently less costly to push junk to bottom than to try to fish it out. And, susceptibility to chemical attack is also being used to advantage in the metal components of some equipment such as swabs and temporary bridge plugs.[5]

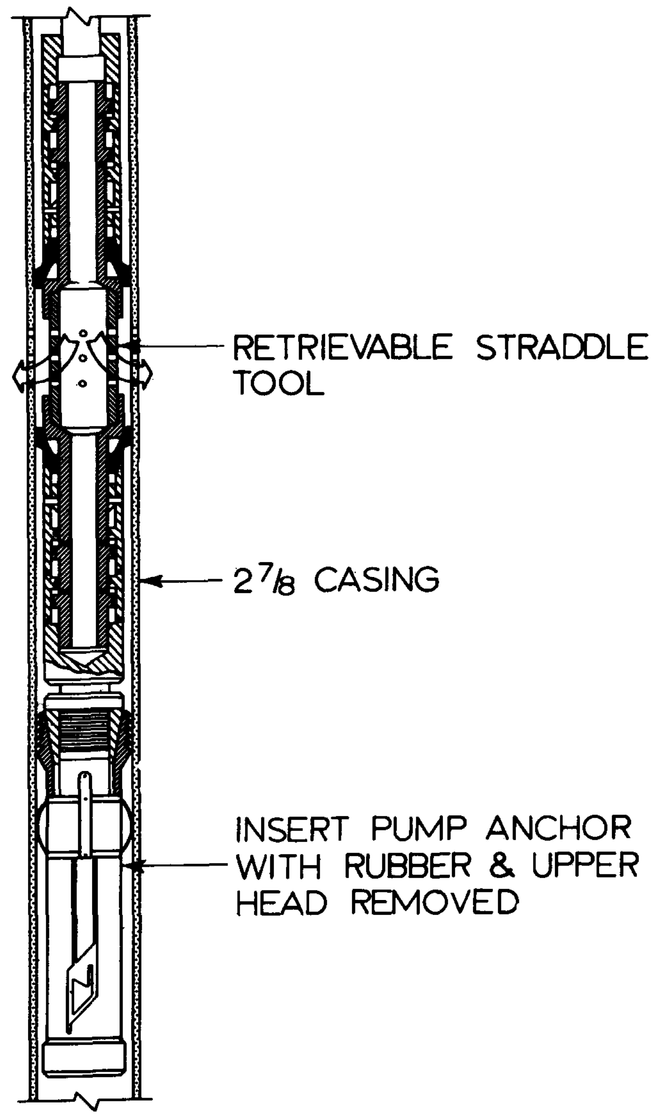

Fig. 12 Treating with Retrievable Straddle Tool

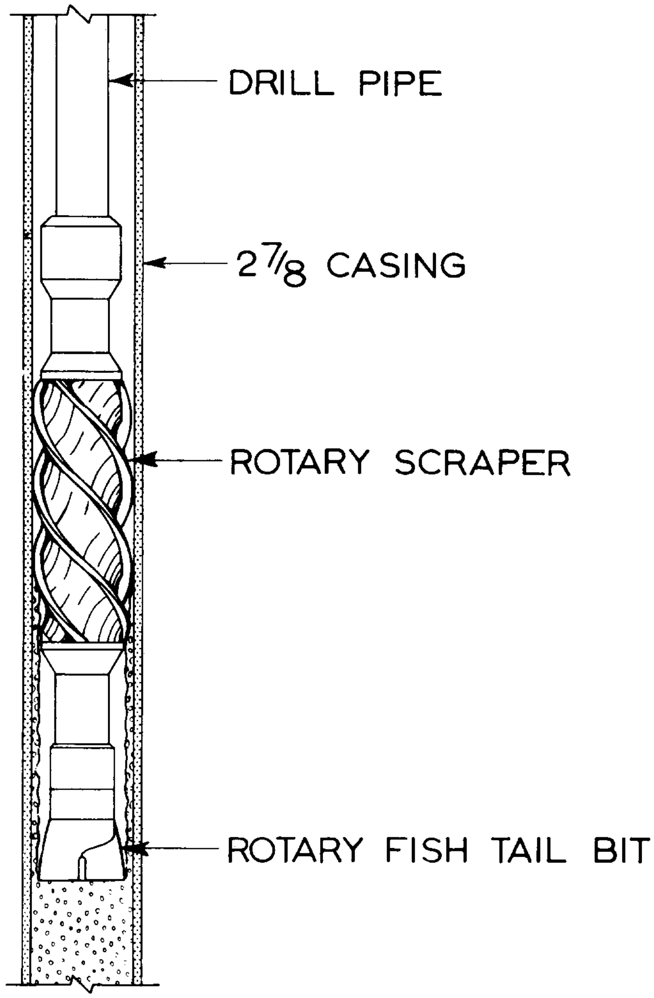

Fig. 13 Drilling Out Cement

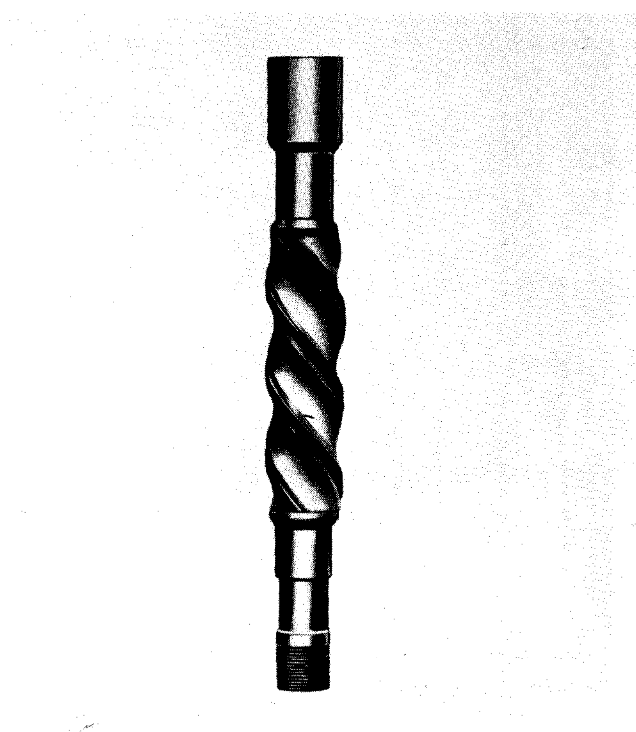

Fig. 14 Rotary Casing Scraper

Retrievable tools pose significant problems primarily because of the very limited amount of space between the required tool ID and casing ID in which to get adequate tool strength and operating control mechanisms and features while at the same time provide running clearance and room for fishing or washing over should the need arise. The very nature of miniaturized tools designed for running inside very small diameter casing tends to make them somewhat fragile, but, generally speaking, fragile equipment has no place in oilfield operations. Therefore, to accomplish the desired objectives, entirely new designs of equipment are, in most instances, required.

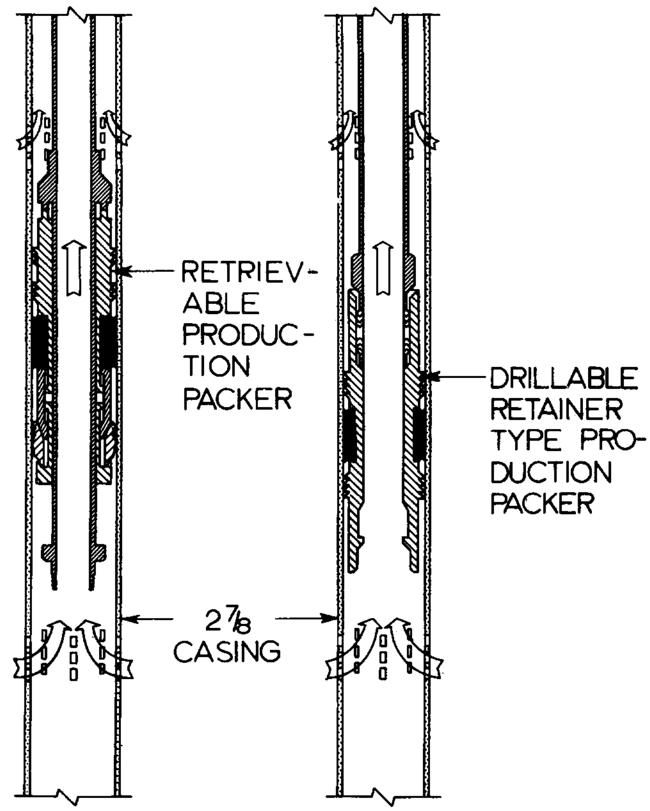

Fig. 15 Dual Completion

SINGLE STRING TUBINGLESS COMPLETIONS

Drilling

Hole sizes for 2 7/8 in. OD single casing string tubingless completions generally range from 6 1/8 in. to 6 3/4 in., a range which provides an unnecessarily large diametral clearance. From the standpoint of the economics of drilling mud and cement, these relatively large hole sizes are undesirable. But smaller bits generally have not been satisfactory because of poor bit life resulting from limited bearing area and tooth strength. However, the demand for such bits provides the stimulus required to justify the cost of their development, and it should be only a matter of time until suitable bits will be made available.

The present limited availability of drilling rigs tailored for small hole drilling is an even more important factor in regard to footage costs. Contractors and operators alike will benefit from the reduced costs that can be realized with the proper equipment. However, it should be brought out that there was more apparent clamor for ultra-light drilling rigs during the earlier phases of the tubingless completion trend when it seemed that this type of completion was practical only for the exploitation of relatively shallow pay zones. Now, there are a considerable number of tubingless completions being made below 8,000 ft with some ranging to deeper than 12,000 ft, and for these deeper completions, much of the presently available drilling equipment is probably well suited.

Originally, there was some concern about the effect of the large annular clearance on the displacement velocity of cement slurry during primary cement jobs. However, experience has indicated primary cementing success is at least equal to the success achieved with larger size casing in the same size bore hole. This increase of success has been attributed to the greater cement thickness and lesser likelihood of channeling with the casing adequately centered.[5]

There was, also, originally some concern about the effectiveness of perforating for completion through the unusually thick cement sheath, but both operators and perforating companies report that the persent perforating guns are giving satisfactory results.

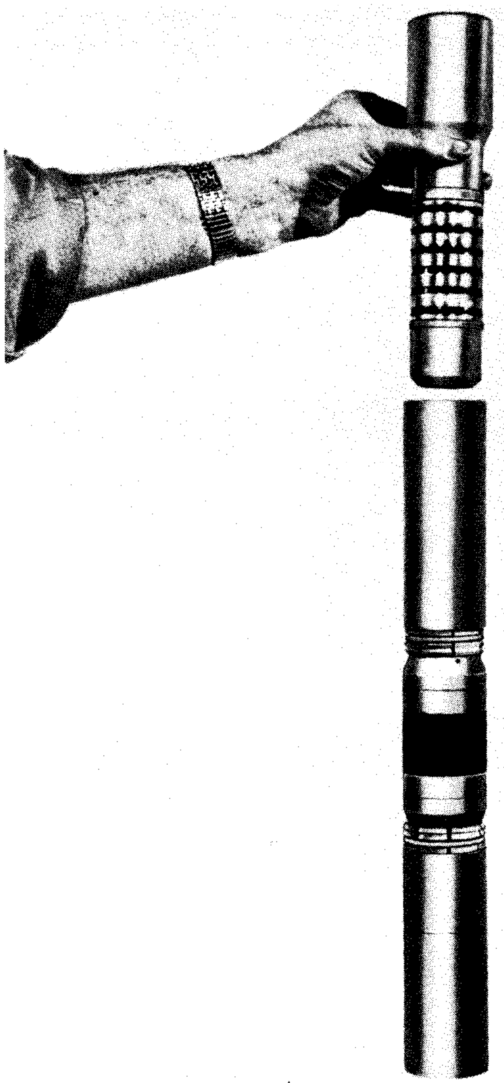

Fig. 16 Drillable Treating & Production Packer

Fig. 17 Retrievable Casing Packer

Casing

The most popular casing by far for tubingless completions has been 2 7/8 in. API tubing. From the standpoint of generally accepted casing string design criteria, the API tubing generally provides an over-designed string; but, considering that cement squeeze jobs and well stimulation treatments are often performed by

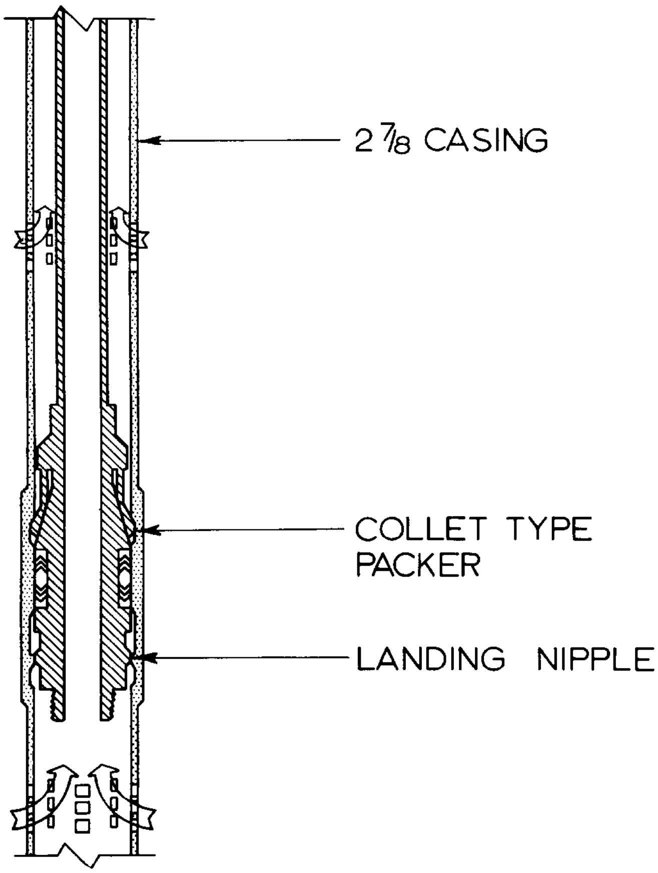

Fig. 18 Dual Completion

spotting the slurry or other fluid through smaller macaroni tubing and then applying the squeeze pressure through the 2 7/8 in. casing, the available burst strength is desirable.

Based on recent requests made to equipment manufacturers, there seems to be increasing interest in larger sizes of casing, such as 3 1/2 in. and 4 in., an interest which is no doubt the result of a desire for increased flexibility in both producing and remedial or repair operations.

Because of the inherent flexibility of 2 7/8 in. casing above the cemented interval, some operators have reported that they are following the practice of landing the casing with substantial tension imposed on it and in addition, are running a drift gage before releasing the rig from the location. This approach appears to be sound, especially when one considers the limited amount of available clearance and the length-to-diameter ratio of equipment that is run into a tubingless well as compared with equipment run into standard sized wells.

Casing Cementing Accessories

Are essentially scaled down versions of standard casing equipment: available conventional type float and guide shoes, float collars, centralizers, reciprocating and rotating scratchers, cementing baskets, and stage cementing collars. Some of this specially designed equipment for tubingless completions includes guide shoes with pump-out noses, latching type cementing plugs, cementing plug landing collars, cementing plug landing-latching rings for installation in standard couplings, and rotation actuated stage collars which make possible essentially full opening passages for the rapid displacement of cement slurry. Also developed are economic rubber Turbulizers which serve to center the casing in the bore hole and, at the same time, cause turbulence in the cement slurry as it is being displaced to minimize the possibility of channeling (Fig. 6).

Completion Equipment

Perforating: Elimination of the attendant problems of expendable perforating gun debris in small diameter casing has been solved with the development of a completely debris-free retrievable steel carrier tubular gun that houses specially designed high performance shaped charges of low explosive weight.[7] Expansion of the tubular carrier has been successfully held to a minimum to permit retrieving the fired gun through API pump seating nipples that are sometimes installed in the 2 7/8 in. OD casing strings. And in one unique design burr interference has also been eliminated by removing some of the metal in the wall of the carrier at the location of each jet discharge.

It is an accepted practice in some areas to run a short pup joint into the casing string near the depth of the producing zone to serve as a marker or datum to aid in accurately perforating thin pay intervals.

Treating: Stimulation and remedial treatments in tubingless completed wells can be performed in the same manner as similar treatments in larger wells, and,

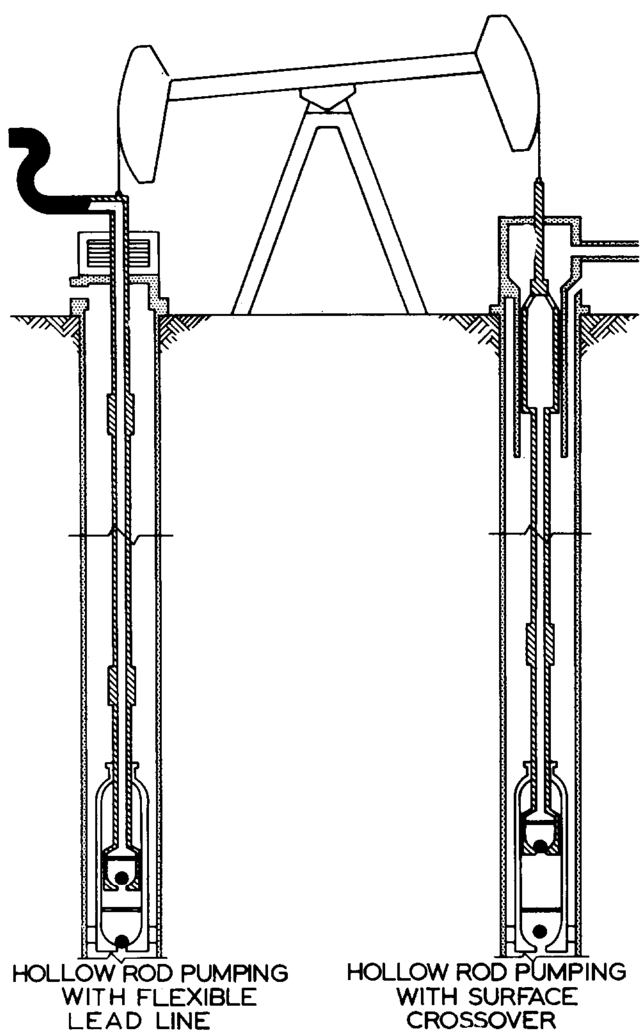

Fig. 19

generally speaking, all the required down-hole equipment is presently available in scaled-down versions of their larger size counterparts. Bridge Plugs currently available include permanent type drillable bridge Plugs (Fig. 7) actuated by wire line setting tools or by integrally carried expansion or explosive charges (Fig. 8) and retrievable bridge plugs (Fig. 9) which can be run and retrieved on either sand line or tubing either alone or below a parent tool.

Proven down-hole pressuring tools are available in permanent type drillable versions or in various retrievable versions. (Figs. 10, 11 and 12.)

Removal of the permanent type drillable bridge plugs and packers is best accomplished with specially designed milling tools run on tubing and turned by power tongs or power swivels. Considerable success has also been achieved with a drilling type sand pump run on sand line.

Completing: Prior to swabbing or running production packers or other similar equipment in tubingless completed wells, it is desirable that possible interference from cement sheath, perforating burrs or other such restrictions or projections in the casing ID be eliminated. To this end, casing scrapers are available which can either be reciprocated or rotated in the casing to effectively clean and smooth the ID surface. (Figs. 13 and 14)

The hazard of sticking a swab while testing or bringing a well in has been minimized by utilizing shear releases or by using metal parts that are susceptible to chemical attack and, therefore, do not require milling or drilling out for removal. There are also available for smaller diameter tubing swabs that can be run as an inner string

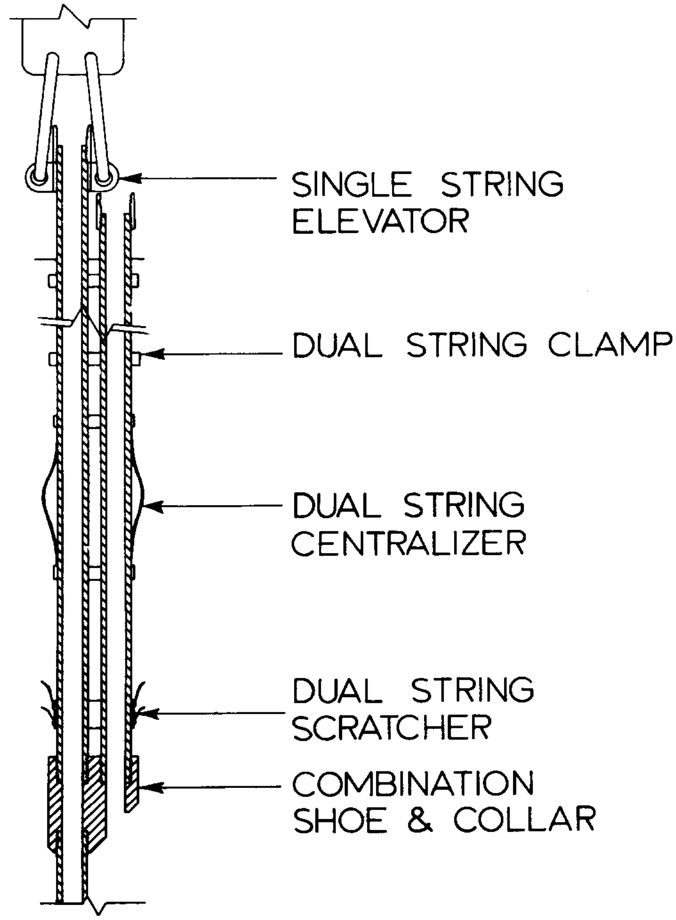

Fig. 21 Clamped Method of Running Dual Strings

where the consequences of sticking or losing a swab are not serious.

In those wells where corrosion is a problem, both permanent type drillable packers and retrievable packers are available so the production can be confined to an inner tubing string (Figs. 15, 16 and 17). Collet type packers (Fig. 18) can also be utilized, providing the landing nipples have been pre-positioned in the casing string as it was being run. Inner tubing strings and packers also make it possible for a well to be inexpensively completed to produce two zones.

Artificial Lifting: Artificial lifting methods currently employed in tubingless completions include virtually all methods that have been employed for years in conventional completions.[8, 9] In many cases, modifications of equipment and/or techniques have been required, but, for all practical purposes, the end result is the same.

The basic methods currently employed to artificially lift tubingless completed wells utilizing 2 7/8 in. OD casing are:

1. Rod pumping with conventional sizes of sucker rods operating inside the casing (casing pumping).
2. Rod pumping with 1/2 in. and 5/8 in. sucker rods operating inside an inner string of 1-1/4 in. or 1 1/2 in. API tubing.
3. Rod pumping with hollow sucker rods operating inside the casing (Fig. 19).
4. Pumping with hydraulically actuated down-hole pumps.
5. Intermittent or continuous flow gas lifting (Fig. 20).

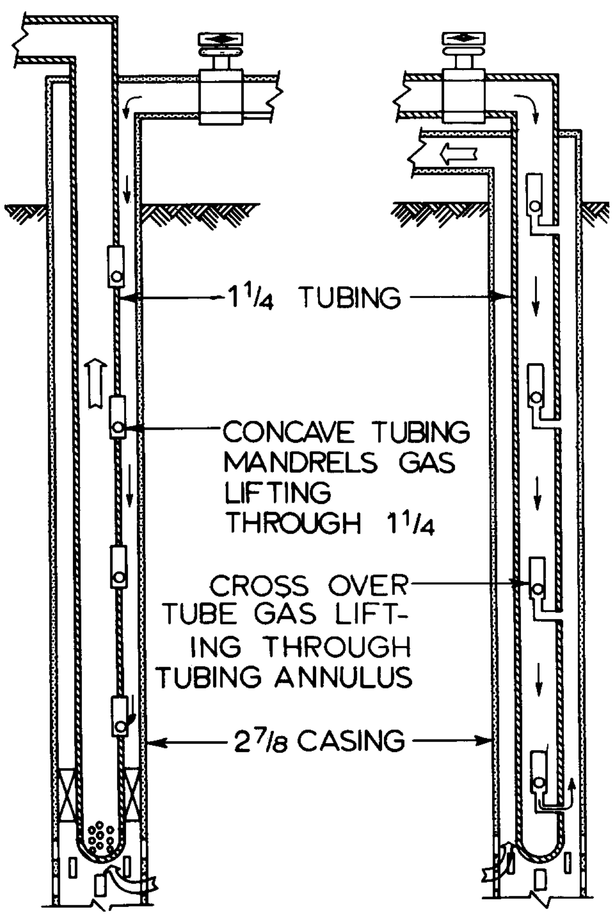

Fig. 20 Gas Lift

In order to select the best method of articial lift for a given well, many factors must be considered. The first consideration is, of course, obtaining the desired production at minimum expense which includes not only the initial capital investment, but installation, maintenance, and operating expenses as well. Well conditions such as sand produced with the fluid, gyp or other scale, paraffin, depth, fluid volume, and gas-liquid ratio are some of the basic parameters that must be considered in making a proper selection of method and equipment to be employed.

An adequate discussion of the merits, limitations, advantages, and disadvantages of each of these methods of artificial lift would be far too lengthy to be included in this paper. However, several very good articles and papers on the various methods of artificially lifting tubingless completions which have been recently published are referenced herein.[1, 8, 9]

Published data and reports from operators indicate that presently available artificial lift equipment for 2 7/8 in. OD casing completions can successfully handle the desired volume of produced fluid in most carea.

MULTIPLE STRING TUBINGLESS COMPLETIONS

Multiple string tubingless completions are those in which two or more strings of tubing are run and cemented as casing in a common well bore for the purpose of exploiting several pay zones. This method of multiple completions differs from a conventional multiple completion in that the conventional large outer casing string is eliminated; thus a somewhat smaller hole can be drilled, and cement rather than packers can be used to isolate the production strings between zones. Each of the cemented casing strings can, in turn, have an inner tubing string and packer for exploiting two pay zones. It would therefore appear that from a mechanical standpoint, the number of possible pay zones that can be exploited by one multiple string tubingless completion is limited primarily by the number of small diameter casing strings that can successfully be cemented in one bore hole with effective zonal isolation.

Dual and triple casing strings are relatively common in tubingless completions and recent trade journal publications indicate that the confidence already gained with multiples is leading to even more imaginative completions. The July 1960 issue of World Oil carries an article on the world's first sextuple well which produces gas from six zones through three strings of 2 7/8 in. casing and three inner strings of 1 1/2 in. tubing. On page 240 of the January 30, 1961, issue of the Oil and Gas Journal is a report on a quadruple oil completion that produces through four strings of 2 7/8 in. casing. In the February 13, 1961, issue in a brief report titled "New Record for Multiples?", the Oil and Gas Journal tells of one operator's request to the Texas Railroad Commission for permission to make 34 completions in eight wells. These completions will consist of one triple completion, five quadruple completions, one quintuple completion, and one sextuple completion and will be used for producing both oil and gas and injecting gas. Also in the Oil and Gas Journal in the February 20, 1961, issue, a report is made on a well that was set up for an octuple completion to produce eight sands through four dual strings, but, unfortunately, only five producable zones were found at the location.

Multiple tubingless completions offer a high degree of flexibility that is used to particular advantage in areas where pay sands are lenticular in nature and tend to make each well a semi-wildcat. For example, if it is anticipated that there will be three pay zones, each to be produced through its own string of 2 7/8 in. casing, an 8 5/8 in. hole is generally drilled. Then three, two, or even only one string of 2 7/8 in. casing can be run and cemented as dictated by the number of pay zones that are actually found at the location.

Multiple Strings

In the early phases of multiple string tubingless completions, there seemed to be a feeling that strings would generally be run clamped together with the short string or strings run as parasites on the long string (Fig. 21). But, running strings in such a manner is both costly and time consuming. It now appears that most operators are running the strings separately since it this method is faster and less costly and also offers the possible advantage of allowing the salvaging from above the cemented section of one or more of the strings at some later date. Each string may or may not have the same type of shoes and collars as are used in single string tubingless completions depending on the operators preference of whether he wants to cement through one or all of the strings. However, experience seems to indicate that best results are obtained by simultaneously cementing through two or more of the strings to obtain maximum displacement velocity of the cement slurry up the annulus.

Available are specially designed rubber turbulizers which have deflecting ribs that provide stand-off between the individual tubing strings and between the tubing strings and the well bore (Fig. 22). The ribs also serve to channel cement slurry into the annular area between the multiple strings, and the turbulizers are generally run from the shoe through the entire critical area to be cemented.

Best primary cementing results have been obtained by using the turbulizers in this manner: reciprocating the strings while cementing and using individual cementing units on each string. In some cases, it has also been found helpful to use low viscosity wash solutions ahead of the cement.[10]

Many operators have found it advantageous to run all strings to bottom for two fundamental reasons: (1) the resulting reduced annular volume through the lower zone aids in obtaining higher cement slurry velocity which, it is felt, results in a better primary cement job; (2) having all strings penetrate the lowermost zone offers the maximum degree of flexibility in completion practices.

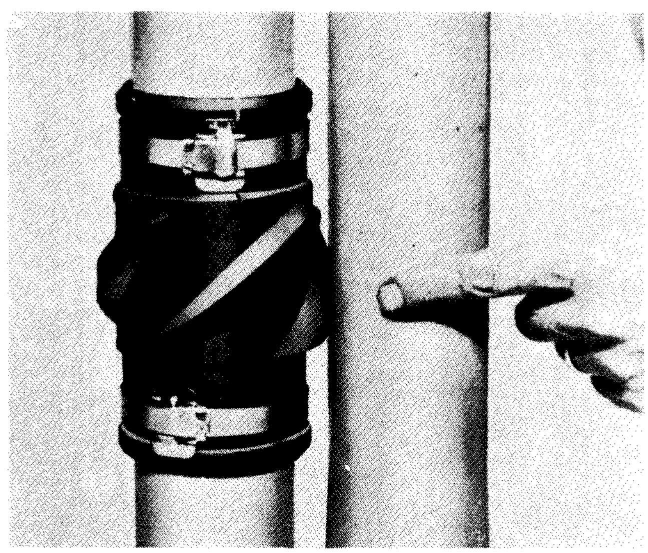

Fig. 22 4 1/8 " Turbulizer Showing Standoff

If the string used to produce the lowermost zone should be junked in that interval for any reason, it can be recompleted to produce one of the upper zones, while the string that formerly produced the upper zone could be recompleted to produce the lower-most zone. The practice of running all strings to bottom must, of course, be tempered by judgment based on economics. If the distance between the zones is not great, the additional capital investment required to have all strings run to bottom can probably be justified.

Special Multiple String Equipment

Most of the equipment used in multiple string completions such as packers, bridge plugs and artificial lift equipment is the same as that used in single string tubingless completions. Of course, special wellhead equipment has had to be devised, and wellhead manufacturers have successfully accomplished this objective. Also made available, has been other special equipment such as multiple string slips and elevators to make it possible for operators to run simultaneously all strings if they so desire.

One of the most unique developments that has been necessitated by multiple tubingless completions is highly specialized orienting equipment for perforating guns so that each string can be perforated as desired with the perforations directed away from the other strings in the hole. The first attempt at this process was a mechanical orienting method which employed special orienting mandrels in the casing strings and special equipment as part of the gun assembly to operate in conjunction with the orienting mandrels.

However, although this type of device had limited success, it had the distinct disadvantage of requiring that the strings be run clamped together to maintain the initial orientation of the mandrels, and required precise prepositioning of the mandrels in the casing strings. Subsequent perforating to recomplete in another zone was, of course, impossible.

Recognizing the severe limitations that the mechanical orienting methods placed on multiple string tubingless completions, perforating companies pursued and successfully developed methods by which the perforating guns can be oriented down hole in relation to the other strings. One such successful method has a mechanical rotator and a focused radio active source attached to the perforating gun. When the gun is rotated in a series of equal steps, radiation detectors suspended in the adjacent strings make it possible for the relationship of the strings at perforating depth to be determined and the gun is fired accordinly in a direction that is away from the other strings.[7]

The orienting perforating method just described has somewhat of a disadvantage in that it requires special perforating trucks to accommodate the multiple lines required for running the radiation detectors as well as the perforating guns. Another orientation method has been developed which requires only a single cable.[11] Using this method, one obtains a surface indication or orientation of the other string or strings themselves, and the need for secondary cables is eliminated.

CONCLUSIONS

Continuing improvements and new developments in tubingless completion equipment and techniques, both for single and multiple string completions, are playing a major role in furthering the widespread usage of this unique method of completing wells. Many of the originally pre-supposed limitations of this type of completion in regard to depth, artificial lifting, and other such factors have been either substantially minimized or virtually eliminated.

In some areas, the tubingless completion method still has not been tried or is only in its infancy; however, in those areas where tubingless completions now comprise a significant percentage of the total number of wells completed the continued success being realized by operators cannot be overlooked.

Equipment manufacturers have accepted the challenge of providing all that is needed to make possible these completions, and the reports from operators indicate that, generally speaking, they are well satisfied. It would appear that there will be increasing utilization of tubingless completions wherever applicable.

REFERENCE

1. M. H. Stekoll and W. L. Hodges, "Use of Small-Diameter Casing Reduces Well Costs", World Oil, Feb. 1, 1959.
2. Paul E. Robinson and R. W. Scott, "Sunray Completes World's First Sextuple Well", World Oil, July 1960.
3. J. E. Willingham, "Tubingless Completions in the West Texas Area", Paper No. 906-4-C presented at the spring meeting of the Southwestern District, Division of Production, Midland, Texas, March 4-6, 1959.
4. "Completion Costs Cut", Oil & Gas Journal, March 16, 1959.
5. J. F. Muse, "Tubingless Completions: A Review of Equipment, Economics and Techniques", Journal of Petroleum Technology, September 1960.
6. "Results of Survey on Slim Hole Drilling Operations", Special A.A.O.D.C. Bulletin, October 7, 1960.
7. M. P. LeBourg and W. T. Bell, "Perforating of Multiple Tubingless Completions", Paper No. 1298-G presented at the fall meeting of the Society of Petroleum Engineers, Dallas Oct. 4-7, 1959.
8. C. B. Corley, Jr., and J. L. Rike, "Tubingless Completions", Paper No. 926-4-6 presented at the spring meeting of the Southern District, Division of Production, March 25-27, 1959.
9. William D. Shannon, "Pumping Installations in Ultra-Slim Casing", The Petroleum Engineer, April 1960 (Part I) and July 1960 (Part 2).
10. R. W. Scott, "Advancements in Production Methods - 1960", World Oil, Feb. 1961.
11. "New Perforation Unveiled", Petroleum Week, Vol. 18, Oct. 30, 1959.