Tubingless Completions

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INTRODUCTION

Small diameter completions have been a part of the oilfield for at least 20 yr, and have been attempted and discarded by many operators over the years because of what was considered to be insurmountable problems or unsound economics. The single reason for consideration of a small diameter completion is to reduce expenditures with no sacrifice in income. However, quite a few small diameter completions have, even initially, cost more than conventional size offset wells.

Today, quite often in the same field, we find 1 operator completing 100% small diameter and on the adjoining lease an operator who has returned to large diameter completions after an experimental program of small diameter completions. Each is certain that he has the most economical method of completing and producing the wells to depletion. Which is right? It would seem doubtful that both could be right. Although it is beyond the scope of this discussion to determine with finality which operator is using the correct method for various types of completions, we can review the major areas of savings, problems, and limitations of small diameter completions on which their decisions are based. This can be of value in serving as a guide in determining the applicability of small diameter completions for any given well.

We will find that, in many cases, the completion problems have been solved; but also, in many phases, the real savings in small diameter completions are not quite as great as originally were imagined. In some wells it may even come down to "dealer's choice": that is, costs for either method would be very nearly equal and either could be produced to depletion with equal success.

In this discussion a small diameter completion will be defined as one with casing too small to accept 2 3/8 in. EU tubing. By this definition we will include 3 1/2 in. OD and smaller casing. A tubingless completion, regardless of diameters, is defined as one completed through the casing, with no tubing.

This paper is a current resume of information recently obtained from interviewing operating and engineering personnel in the Texas Panhandle, West and Southwest Texas. The current practices, problems, and basic econmics of each of the following individual phases will be discussed in the order listed.

Drilling	Fracturing
Tubular Goods	Swabbing
Well Heads	Tubingless vs. Tubing
Cementing	Artificial Lifting
Perforating	Workovers

DRILLING

Drilling would at first seem to be a logical phase of operations to expect reduced costs; however, this has not generally been the case for operators in all geographic areas covered report that most holes are drilled to full size. Drilling costs have been reduced in selected shallow wells drilled with portable light weight rigs.

Several years ago it was anticipated that small diameter bit lite would be limited because of bearing failures. This has not proven to be the problem. The limited tooth length possible in smaller bits has been responsible for shorter bit life. The shorter bit life can be partially offset by higher penetration rates, provided, of course, optimum hydraulics are employed.

To be able to bid on the small diameter hole, the contractor would have to purchase new drill pipe, drill collars and greater horsepower high pressure pumps to drill the slim hole. Under ideal conditions with proper equipment, he could expect no more than 5% cost reduction in the small diameter hole. Also, there is the additional risk of expensive fishing job complicated by the reduced diameter hole. Because of the relatively small savings possible under ideal conditions and the strained economic position of the drilling contractor, there would seem little reason to expect a significant increase in slim hole drilling.

Because of a lack of participation and free exchange of techniques within the industry, the "Slim Hole Sub-Committee" of AAODC's Rotary Committee has gone on a standby status for the first time since its formation in 1956.

TUBULAR GOODS

The selection of tubular goods used in the small diameter completion has proven to be the major area of savings in the small diameter well. If the low bid for drilling a well is to "standard gage," the surface casing must be the same as used in a conventional size completion, so the only tubular goods saving possible would be in the selection of the oil and tubing string. This can be a significant amount, and with the present profit squeeze, every avenue of saving must be thoroughly investigated.

If casing larger than 2 7/8 in. is required for the small diameter single completion, 4 1/2 in. is the next choice, as there is only a 2¢ to 15¢ per foot cost differential between 3-1/2 in. and 4 1/2 in. casing.

There seems to be a growing interest in the use of 3 1/2 in. OD casing in the multiple parallel, small diameter completions. The minimum combined diameters of three 3 1/2 in. OD NU couplings is 9.156 in; the minimum combined diameter of three 2 7/8 in. OD NU couplings is 7.540 in. The surface casing for either size of oil strings would probably be 10 3/4 in. OD. In many cases the only additional cost for a 3 1/2 in. completion would be the $1.50 - $3.00 per ft. cost differential of 3 1/2 in. over 2 7/8 in. casing. The 3 1/2 in. casing permits higher cement displacement rates and with less relative volume in the well bore a better flow rate in the annulus is attained. The 3 1/2 in. casing also provides greater tubing-casing annular area for venting gas and less risk of sticking the 1 1/2 in. tubing in a rod pumped installation. The increased annular area is also advantageous in many gas lift installations. Minimum combined diameter of three 4 1/2 in. casing couplings is 10.78 in., which would require larger surface casing, greater drilling costs, as well as additional cost for the casing and make this initially more expensive than the small diameter parallel multiple. Most operators reported isolated use of 2 3/8 in. casing. Generally, this was applied only to marginal gas zones or for low volume injection or disposal purposes. Table I indicates relative prices of small diameter tubular goods, and the examples given indicate possible savings.

WELLHEADS

A complete line of wellhead equipment is available for the small diameter completion, but there may be little or no saving in this phase of completion.

Wellhead equipment for a single completion, for example, would compare 7 5/8 x 4 1/2 x 2 3/8 in. for a conventional completion, and 7 5/8 x 2 7/8 x 1.900 in. for a small diameter completion. In each case suspension and sealing is required for one casing string and one tubing string.

Wellhead equipment required for a "typical" large diameter multiple completion would be a 10 3/4 x 7 5/8 x 3, 2 3/8 in. system, which would support and seal off 1 string of casing and 3 tubing strings. An equivalent small diameter completion would require a 10 3/4 x 3, 2 7/8 x 3, 1 1/4 in. wellhead system. This involves suspension and sealing of 3 strings of of casing and 3 tubing strings. In this comparison, as shown in Figure 1, the small diameter completion with a total of 6 strings to support and seal is more complex than is the large diameter head with a total of 4 strings to support and seal.

CEMENTING

Cementing of a single string of small diameter casing presents no unique problem and is as successful as are large diameter completions in the same areas; but also no savings can be effected in this phase of small diameter completion. The same quantity of accessory equipment, such as centralizers and scratchers, is required; and the greater annular volume will require additional cement for proper fill.

Cementing the multiple parallel cased well has been the greatest single source of trouble in small diameter completions and has been the predominant completion problem that has caused operators in some areas to abandon use of small diameter multiple completions. Operators have experienced extreme difficulty in zone separation with multiple parallel strings in areas where a good primary cement job is no problem with a single string of full size casing. Although primary cementing failures are a continuing problem, they have been reduced in many areas, through improved techniques, to a level that makes the small diameter completion economically attractive for selected wells.

In any primary cementing job it is desirable to use all available pump capacity when displacing the cementing plug to achieve turbulent flow in the annulus. Those who are completing small diameter wells today and who were interviewed emphasized the need for maximum possible displacement rates to aid in obtaining a good primary cement job. This usually means using both pumps on the cementing truck for each casing string.

If economically possible, 2 strings of casing should be run to total depth for this will permit higher flow rates by cementing through two tubing strings. It is doubly desirable to have 2 strings of casing to total depth for cementing; and as added insurance in case the lower zone of 1 should become permanently plugged, it would be possible to complete in the other casing string. If there is a very great distance between zones of interest, the cost of added second string length will detract from the original savings of the small diameter completion.

If well conditions permit, a slug of water or chemical wash ahead of the cement has proven to be beneficial in reducing the channelling problem. Because of possible blowout, sloughing or lost circulation, application of this aid must be evaluated for each well.

Difficulty is frequently reported in running long, close fitting tools in the smaller casing because of bending and buckling of the casing. The reduced compressive strength of the small casing and the relatively large well bore clearances have resulted in the common practice of holding 2000 - 2500 psi in the casing while the cement sets to aid in insuring straight casing when the cement sets. Internal casing pressure will tend to shorten the casing because of helical buckling and ballooning. It will tend to elongate it because of pressure acting on the end area sealed by the cementing plug. The net elongation force may be calculated as $F = 0.4\ A\ P_i$ where A = area of the casing I.D. and Pi is the net pressure differential inside the casing.[2] If this practice is followed, there must be no leaky connections as a loss of pressure would result in movement of the casing during cement curing.

Cement bypassing the final plug was a serious problem a few years ago, but this has been very satisfactorily solved with the modified "rubber ball" type of latching cementing plug. Use of this type of cementing plug and extreme care in flushing all lines and pumps before displacement has eliminated the problem of cement to drill out above the cementing plug. One point to remember when using this plug is to always plan to have the plug below any zone of interest, for drilling the solid rubber plug is generally quite a slow process.

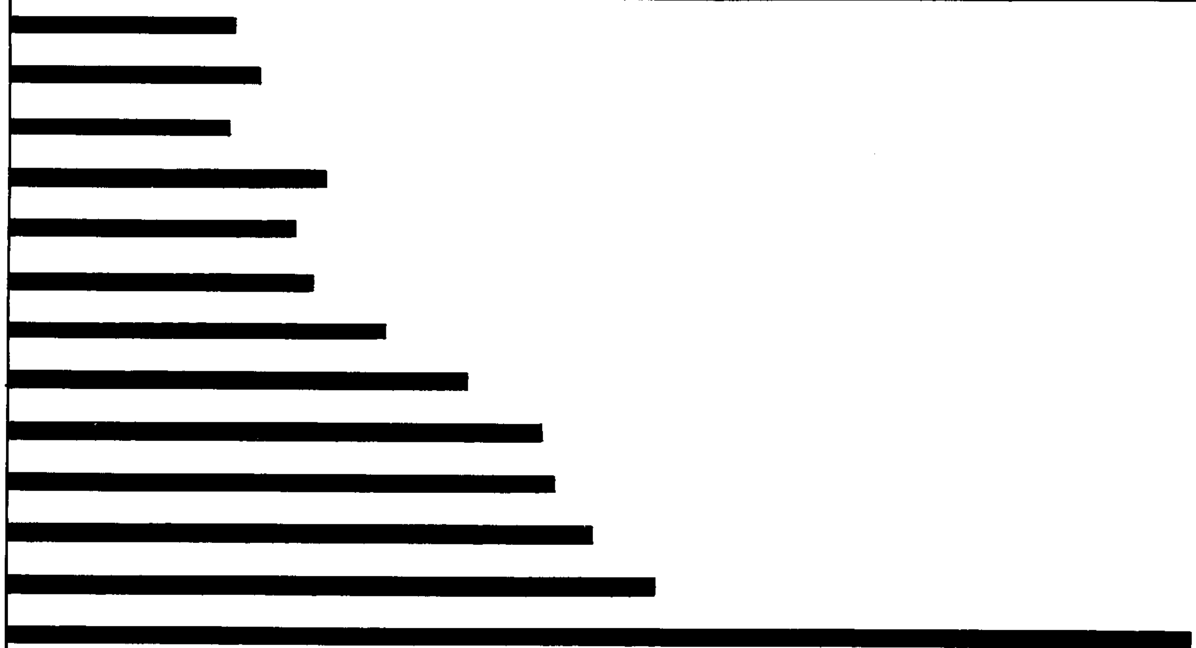
A common practice in an area of the Texas Panhandle with nearly 2000 ft between production zones, which results in 90-95% primary cementing success, is the method diagrammed in Figure 2. Regular steel spring centralizers and conventional steel wire reciprocating scratchers are run on each joint of each casing string through the cemented interval. The conventional scratchers on the combined casing strings effectively remove filter cake on the face of the well bore, as shown in Section AA of Figure 2. The casing strings are run and cemented independently, but are simultaneously reciprocated and use dual elevators. Retarder is added to the long string cement to prevent its setting until after completion of the short string cementing.

This method does have the disadvantage of extra cost for the dual elevators and the risk of buckling the casing since, with wellheads commonly used, the casing is landed with the last casing movement down. One operator, in fact, reported difficulty on 1 well because of a buckled long casing string through the upper cemented interval.

From Southwest Texas it is reported that, although the primary cementing method diagrammed in Figure 3 is not 100% successful, it is far superior to the 60% failure recorded in that area during the first years of

RELATIVE PRICE COMPARISON CHART

SIZE	WEIGHT	THREAD	PRICE
1.315	1.80	E. U.	
1.660	2.40	E. U.	
1.900	2.75	N.U. (WELDED)	
2.00	3.40	BUTTRESS	
2.375	4.60	N.U.	
2.375	4.70	E.U.	
2.875	6.40	N.U.	
3.500	6.90	N.U. (WELDED)	
3.500	9.20	N.U.	
4.500	9.50	N.U.	
4.500	10.50	N.U.	
4.500	11.60	N.U.	
7.00	23.0	N.U.	

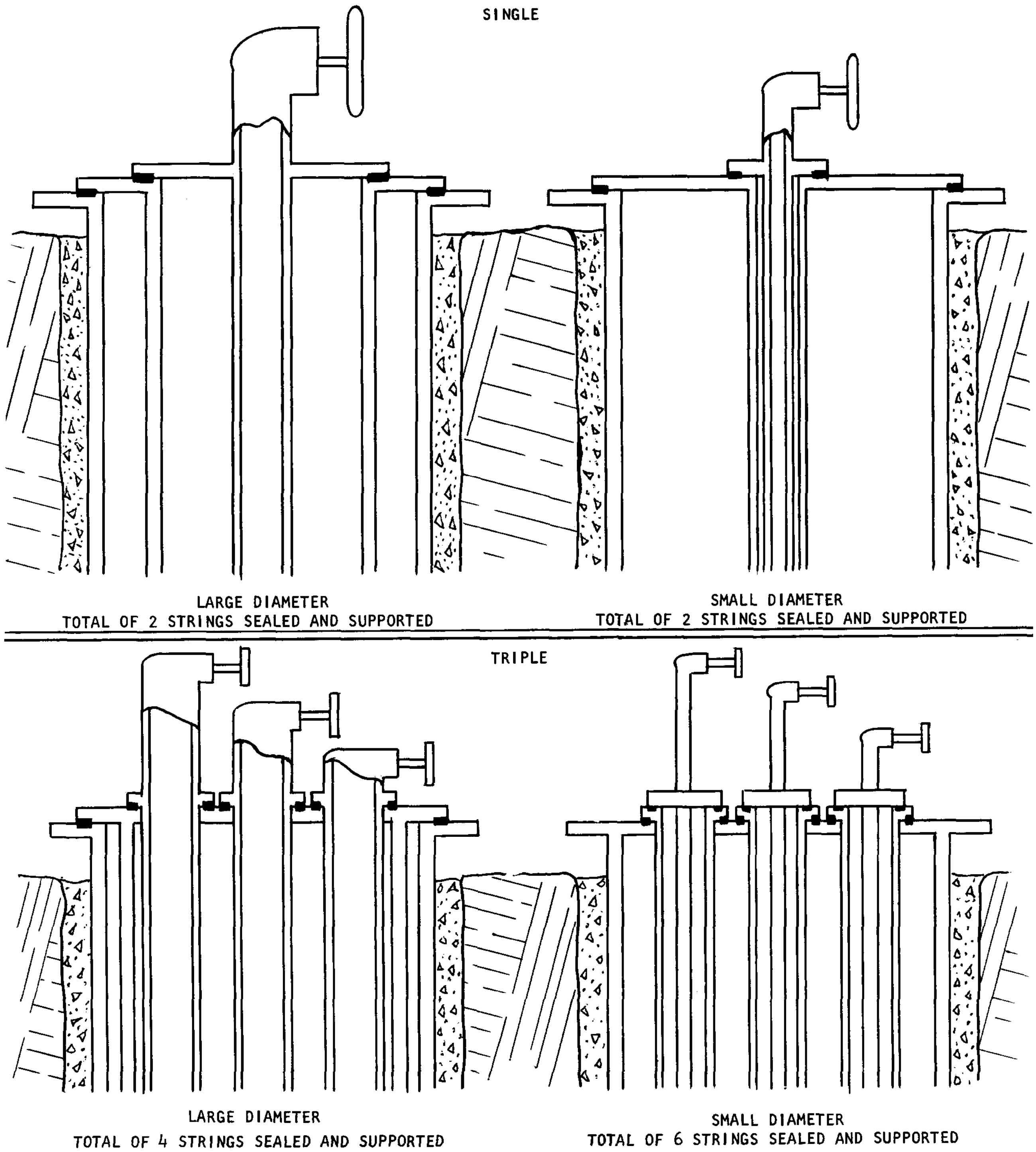


EXAMPLE

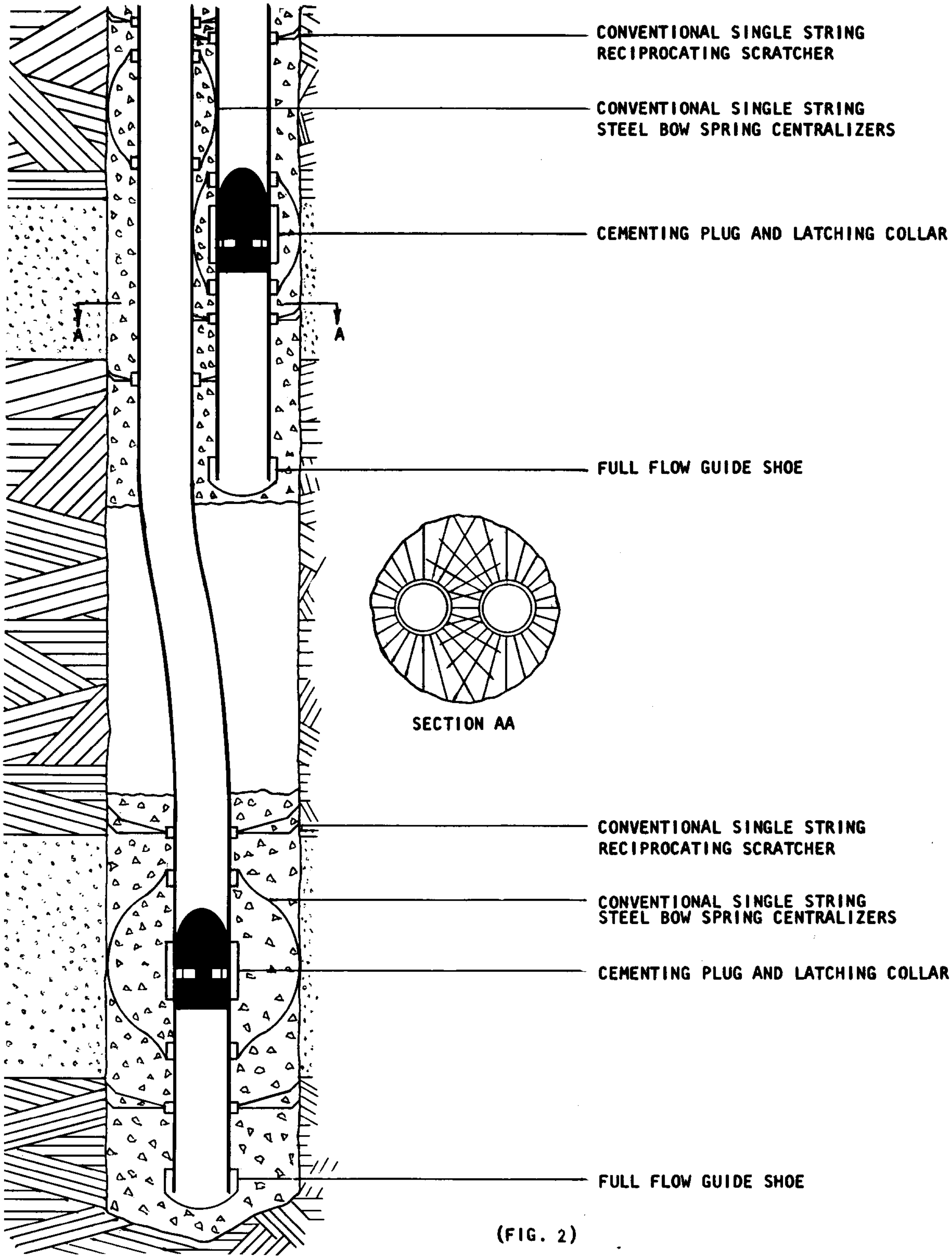
COST REDUCTION IN TUBULAR GOODS FOR A SMALL DIAMETER COMPLETION

Single Completion at 5000'			Dual Completion at 5000'		
ITEM	CHANGE	APPROX. SAVINGS	ITEM	CHANGE	APPROX. SAVINGS
Oil String	4-1/2 - 2-7/8	$1,100.00	Oil String	1-7" - 2-2-7/8	$4,150.00
Tubing	2-3/8 - 1.900	830.00	Tubing	2-3/8 - 1-1/2	1,670.00
		TOTAL $1,930,00			TOTAL $5,820.00

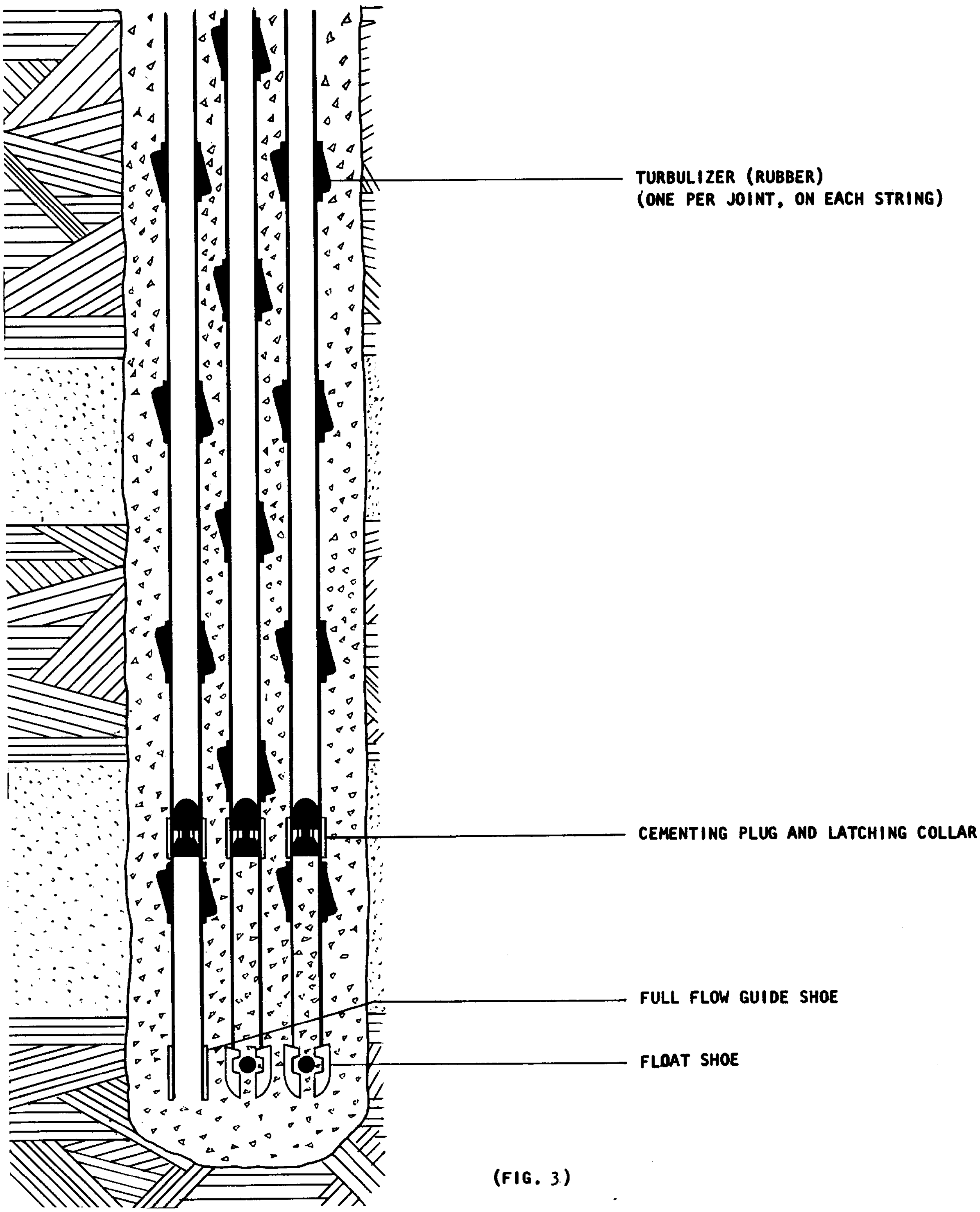
(TABLE - I)


SINGLE
LARGE DIAMETER
TOTAL OF 2 STRINGS SEALED AND SUPPORTED
SMALL DIAMETER
TOTAL OF 2 STRINGS SEALED AND SUPPORTED
TRIPLE
LARGE DIAMETER
TOTAL OF 4 STRINGS SEALED AND SUPPORTED
SMALL DIAMETER
TOTAL OF 6 STRINGS SEALED AND SUPPORTED

(FIG. 1)

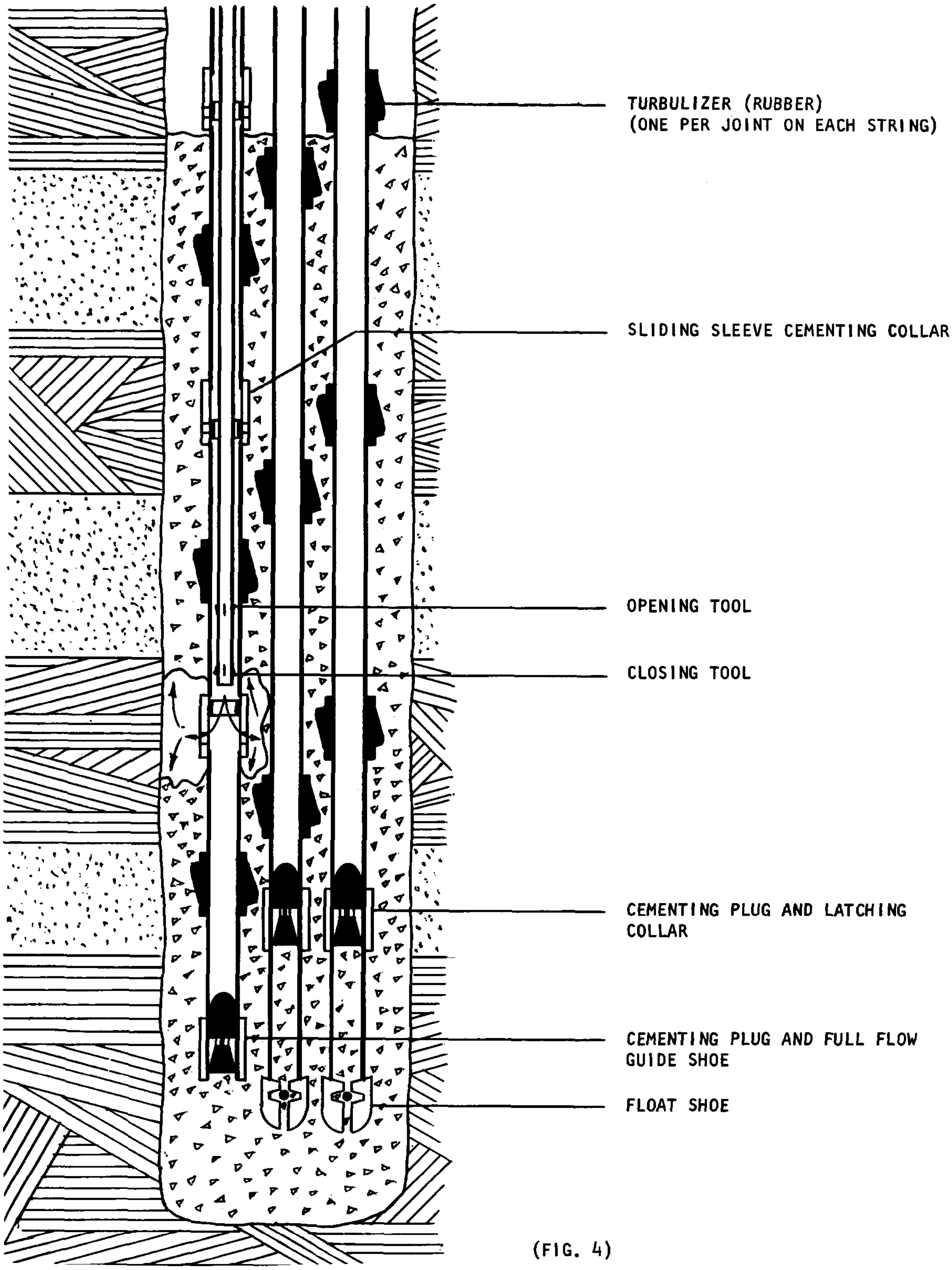

CONVENTIONAL SINGLE STRING
RECIPROCATING SCRATCHER
CONVENTIONAL SINGLE STRING
STEEL BOW SPRING CENTRALIZERS
CEMENTING PLUG AND LATCHING COLLAR
A
A
FULL FLOW GUIDE SHOE
SECTION AA
CONVENTIONAL SINGLE STRING
RECIPROCATING SCRATCHER
CONVENTIONAL SINGLE STRING
STEEL BOW SPRING CENTRALIZERS
CEMENTING PLUG AND LATCHING COLLAR
FULL FLOW GUIDE SHOE

(FIG. 2)



TURBULIZER (RUBBER)
(ONE PER JOINT, ON EACH STRING)
CEMENTING PLUG AND LATCHING COLLAR
FULL FLOW GUIDE SHOE
FLOAT SHOE

(FIG. 3)


TURBULIZER (RUBBER)
(ONE PER JOINT ON EACH STRING)
SLIDING SLEEVE CEMENTING COLLAR
OPENING TOOL
CLOSING TOOL
CEMENTING PLUG AND LATCHING
COLLAR
CEMENTING PLUG AND FULL FLOW
GUIDE SHOE
FLOAT SHOE

(FIG. 4)

development of small diameter multiple parallel completions. All casing strings are run independently. As soon as the first string is to total depth, it is landed and circulation is established and continued at a rate of approximately 3 BPM until the second and third strings are landed. It is of interest to note that when the first string is circulated while running the remaining strings of casing, the remaining string must be equipped with a float shoe to prevent overflow while running. This is not necessary when running casing in small diameter wells not being circulated. After all strings are landed, the first string is displaced with oil by using the latching type cementing plug. Immediately upon completion of displacement of the first string, simultaneous cementing of the second and third strings is conducted. All strings are shut in with 2000 - 2500 psi while the cement sets.

Because of extreme difficulty in obtaining a satisfactory primary cement job, operators in several areas have resorted to use of cementing sleeve valves, as diagrammed in Figure 4. The sleeve valves are an added initial expense; but, in areas with historically difficult primary cement jobs and in which perforating to segregate zone is imminent, the sleeve valves result in a net savings. The valves are generally run on a string through which no cement is to be pumped. Also, the casing string with the cementing valves is usually completed in the uppermost zone to prevent accidental opening of the valves while casing swabbing during completion of the well.

After the primary cement has set, an opening and closing tool is run on 1 in. tubing to open, test, and squeeze, if necessary, and close the valve. Testing is started with the lower valve and all valves in sequence can be actuated and squeezed as required with a single trip of the tubing. Operators report that the valves have opened and reclosed readily even after several cement squeezes.

One Southwest Texas operator interviewed is showing a considerable saving in small diameter completions by using a low pressure squeeze cementing method. He is using a skid-mounted cementing unit furnished by the completion rig contractor. Using this unit at a rental of $50 per squeeze certainly shows up as quite a savings, particularly in an area requiring several squeeze jobs. This cost cutting method could be equally well applied to large diameter completions. It emphasizes the point that operators using small diameter completions are spending considerable time and effort to explore all possible avenues of cost reduction.

There are, of course, endless modifications and variations of the three basic methods described, Manufacturers of primary cementing equipment have a complete line of equipment for 3 1/2, 2 7/8, and 2 3/8 in. casing.

PERFORATING

A complete service in logging and perforating is offered by all major service companies. One area of considerable concern during development states was in orientate perforating. All operators report that misdirected perforating is extremely rare. One operator reports only 4 failures in a total of 854 perforating jobs last year. This was using several of the service companies and both the single and multiple line method of orientation with equal success.

Although the mechanics of orientated perforating is very successful, extreme caution must be exercised in interpreting the density log to determine the correct perforating direction.

Perforating the single small diameter completion with current equipment, even though a thick cement sheath, is reported to be trouble free, and to provide adequate penetration.

Reports of a few years ago were showing, in small diameter completions, a saving by reducing perforation shot density. Most operators today are using the same perforation density in small and conventional diameter wells. There would seem to be little reason to complete with a lower perforation density in small diameter wells. Due to additional time and expense of orientated perforating, this phase of small diameter completion will be slightly more expensive than a standard multiple completion. Also, because of lower success ratio of the primary cement jobs in small diameter multiple parallel completions additional perforating may be required for extra cement squeezing.

FRACTURING

Fracturing the small diameter well presents no particular problem; in fact, the higher burst strength of the small diameter casing permits breaking down the fracing down the casing in areas not previously possible with larger casing. The only serious limit in fracing a small diameter completion would be the maximum injection rate possible for a given size casing. In the majority of the wells this is not a problem.

Fracturing, or any high pressure operation in the small diameter multiple has one problem that it seems everyone has had to learn to correct through experience. Adjacent casing strings must be pressured to avoid collapse. It is common practice to attach a pressure recorder to the adjacent strings for proof of pressure maintenance.

Reports a few years ago showed quite a saving in small diameter wells with a lower injection rate frac than would be used in a large diameter well. This practice is not currently widespread, for most operators feel that a formation requiring a given frac rate would not produce as desired with a lower rate frac, merely because the zone was to be ultimately produced through small diameter casing. There was at one time concern expressed about the effective use of perforation sealer balls in the small diameter casing. The concern was that the high velocity of the fluid in the small casing might prevent proper seating of the sealer balls on the perforations. One Texas Panhandle operator reports successful use of perforation sealer balls in 2 7/8 in. casing with frac rates of 10 BPM. The perforation shot density in this case is 2 per ft. It is doubtful that they would be entirely satisfactory much above this rate. When a higher rate frac is required, the method reported by a West Texas operator fracturing at rates up to 24 BPM in 2 7/8 in. casing is of interest. The formation first is broken down at a lower rate, using the sealer balls; then, after a satisfactory breakdown, pressure is released and a sinker bar is run to clear the perforations of all sealer balls. The frac is then continued at the increased rate. This system is used with the "limited entry" frac technique. Simply stated, the limited entry technique employs perforating sufficiently few holes to insure injection of fluid through each perforation at a rate predetermined possible for the zone.

SWABBING

Swabs are readily available for 1 1/2 and 1 1/4 in. tubing, but due to increased volume the majority of small diameter wells are casing swabbed. Prior to the introduction of aluminum swab bodies with a shear pin release to the swab line, several expensive fishing jobs resulted from stuck swabs. All casing swabbing today employs the shear pinned aluminum body swabs. One precaution to observe in using this equipment is to replace the shear pins frequently to prevent premature loss of the aluminum swab body. Shear pins usually are replaced after 3 to 4 runs.

TUBINGLESS VS TUBING

A few years ago, reports which indicated savings of 30% or greater by using small diameter completions were based on truly tubingless small diameter completions. This method of completion is definitely in the minority today; and, in fact, many of the original tubingless completions have been recompleted with tubing. The same problems of corrosion, stuck casing pumps and paraffin deposits in the casing that plagued full size completions without tubing became just as evident in the small diameter tubingless completion. Today, 1 major operator reports no more than 1% of his rod pumped small diameter completions are tubingless. If present intentions are carried out, this percentage will decrease; however, there are areas reporting continued interest in tubingless completions.

Small diameter tubingless completions have led to development of a high performance Retrievable Pump Seating Shoe, permitting operations to depths limited only by other components of the pumping system. This eliminates the objectionable reduction of the casing I.D. with permanent seating nipples in the casing string.

ARTIFICIAL LIFTING

The "standard" rod pumped completion in West Texas small diameter completions uses 1 1/2 in. integral joint tubing, a 1 1/16 in. insert pump, and 5/8 in. rods with turned down connections, or 1/2 in rods. The great majority of wells today can be produced within the capacity of this pump. This method of pumping does detract considerably from the savings possible with a casing pump type installation, but most operators feel the lesser risk, gas venting, and chemical injection features are a good investment.

Hollow rod pumping was widely applied several years ago and seemed to be an economical method of pumping a small diameter well. It permitted venting of the gas and a means of adding desired chemicals to combat corrosion and/or paraffin. The problems of poor rod fall because of an unbalanced hydraulic condition, buckling of the hollow rods, severe wear of the rod OD and casing ID, has greatly curtailed the use of this pumping method for new wells. In a closed end tube system the tube is prevented from buckling by the resultant force of pressure acting on the closed end by the tube. If the end area force is supported by some means other than the tube, the tube will buckle. On the downstroke of the hollow rod pump, the end area force of the internal pressure is supported by the standing valve, and the hollow rods will buckle, often very severely.[2] Some of the early installations have been modified to fill the annulus with inhibited oil to reduce friction, wear, and buckling, but this also eliminates the possibility of gas venting and chemical injection features. Several of the hollow rod installations have been converted to small diameter tubing and insert pump.

The complete line of both insert and tubing pumps are available for the small diameter completions. Tubing Anchors are also available and used by many operators to increase pump efficiency and reduce wear by eliminating tubing breathing and buckling.[3]

Hydraulic pumps are used to considerable advantage in the small diameter completion to produce a greater volume of fluid and to greater depths than possible by other means. One operator reports very satisfactory service with hydraulic pumps, using a 3/4 in. power oil string, producing through the annulus of the 3/4 - 1 1/2 in. tubing and venting gas up the 1 1/2 - 2 7/8 in. annulus. This hookup is used in several triple zone small diameter completions.

Both insert and free hydraulic pumps are available for the small diameter completion. Several operators report savings by using hydraulic pumps, especially in the multiple parallel installation.

Small diameter gas lift installations in high fluid level wells have been entirely satisfactory in many areas. However, attempts to gas lift from greater depths has not been quite as successful as would be desired. The limited annular flow area and restriction imposed by the gas lift valve make deep gas lift installations less practical in the 2 7/8 in. cased wells.

WORKOVERS

Workover operation in the small diameter well has not been the problem that many had originally anticipated. Operators report that they can perform any required workover in small diameter wells with success equal to that of large diameter wells. However, unless specially designed rigs are available, workover operations in the single small diameter well will quite often be slightly more costly than a large diameter well.

This will be due to the same cost per hour for the rig, slower overall operations because of cautious handling of the small diameter equipment, and slower cement drillout time in the smaller casing. Slip type elevators or lifting plugs will be required for the integral joint production tubing commonly used. It is also common practice to change over to a 1 in. workover string, rather than risk damage to the integral joint production string. Increased net costs for rig time and special equipment all add up to slightly increased costs.

Manufacturers of remedial tools offer a complete line of drillable and retrievable tools to duplicate any operation possible in large diameter casing. Although initially small diameter tools were in many cases quite fragile, the tools have been strengthened and refined until, today, they are fully as successful as the larger diameter tools. Due to closer tolerances and increased manufacturing time, a few small diameter tools may be slightly greater in cost than is equivalent equipment for large diameter wells.

Workover operations in the multiple parallel small diameter well may be significantly less costly than is the same operation in large diameter casing with parallel tubing strings. This will be due to use of a smaller rig to handle the macaroni tubing and the ability to workover 1 zone without killing or even halting production of the other zones.

The multiple parallel small diameter completions are really just a series of single completions in one well bore. In many operations they can be treated as individual wells. One exception is to always consider the danger of collapsing adjacent casing strings when conducting high pressure operations. This can be avoided by maintaining sufficient pressure inside the adjacent casing strings. In specific areas, such as those with 1 zone requiring frequent servicing, or wells with 1 zone of high pressure and the other with pressure too low to hold required hydrostatic to keep the well under control, operations will be less costly and simplified with multiple parallel small diameter completions.

To date, the only dual completions within a single string of small diameter casing have been concentric with lower zone flowing up the tubing and the upper zone flowing up the annulus.

SUMMARY

Operators have found that there are limitations which preclude the use of small diameter casing. Several of the more common ones are:

1. Zones in the future may require handling of large volumes of water.
2. High gas oil ratio wells may require larger casing for proper venting and optimum pump efficiency.
3. Deepening to new zones is very limited.
4. Future dual completion possibilities are very limited.
5. Successful primary cementing of multiples may be difficult and prohibitively expensive.

For selected wells the small diameter methods of completions can be used to a considerable economic advantage. Possible avenues of savings are:

1. Tubular goods: major savings here in this phase.
2. Stimulation and treatment costs: may be lower due to "down the casing" operations.
3. Workover and servicing costs: lower generally only in some multiples, primarily due to uninterrupted production of adjacent zones.
4. Drilling: but only in the shallow single completion.

The single reason for interest in small diameter completions has been to reduce expenditures with no decrease in income. Experience has proven that many small diameter completions have cost more than a comparable conventional size completion. This is to be expected during the apprentice period of any new procedure. Many small diameter completions have resulted in profitable development of properties too marginal for conventional completion methods. Operators, who have worked with this method and stayed with it, have learned that many wells simply are not suitable for small diameter completions; however, through prudent applications and sound engineering, they are completing "small diameter" with significant savings, resulting in additional funds for expanded operations.

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