Routes to Lower Well Cost

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Despite a sharp decline in number of wells drilled during recent years, the U. S. petroleum industry continues to spend nearly $2-1/2 billion annually for the drilling, completing and equipping of new wells. This is the largest single item of expense for the U. S. petroleum industry, accounting for approximately one-third of the industry's total annual capital expenditures and two-thirds of all production expenditures.

The magnitude of this expenditure demands a concerted effort be made to reduce the cost of new wells. In addition, recent inexorable economic pressures increase the need for lower well costs. Producing profits have been trimmed by the failure of oil prices to match a general rise in costs. Increasing well depths add to the problem, since well costs accelerate rapidly with depth. A larger percentage of the wells are being drilled offshore, where costs are much greater than elsewhere. Under these conditions, frugality is a necessity.

Neither a reversal of economic tides nor dramatic new drilling techniques can be anticipated to bring sudden needed relief. Therefore, the solution must be sought through refinement and improvement of current practices, policies and concepts.

BENEFITS FROM JOINT PLANNING

Despite foregoing limitations, sizable reductions probably can be achieved in reduction of over-all well costs. Three industry groups are involved: contractors, operators and service-supply firms. To be effective, assaults on well costs must be an organized joint effort of these groups.

The best possibility for initiating such activity is for operators to act as the catalyst for unifying these parties into a

Contractor
Operator
Service-Supply
Team

for the purpose of seeking techniques and practices on a field and area basis that will give minimum well costs.

Individual companies could do this by scheduling periodical division and regional conferences between these three groups to critically examine the whole range of conditions, problems, practices and policies. The goal would be to design programs which best fit all conditions at the most economical cost, then alter the program to best fulfill the combined needs of the contractor, oil company geological and production departments, and service company operations. Studies should include bit selection, bit weight, hydraulics, rotation speed, drilling fluids, casing programs, deviation, and other hole difficulties. By all means, contractual responsibilities and liabilities should be an important part of these conferences.

Obviously, such conferences offer far greater savings possibilities in field development work. This should not be considered a serious drawback, as field wells constitute 75% of all drilling.

Such conferences could foster mutual cooperation, promote understanding, eliminate wasteful practices and policies, clarify responsibilities, and assure use of the most advanced hole-making skills and well programs. The over-all result would be more economical operations for contractors, operators and service-supply companies.

Operators would have to assume the responsibilities for achieving the correct atmosphere at these conferences before contractors and service-suppliers would feel free to express themselves on customer practices. Much can be accomplished if each party could be encouraged to lay his recommendations on the table for open study.

W. A. Alexander, Vice President of the Denver Region for Shell Oil Company, credits this conference idea with playing an important role in achieving a 25% reduction in footage costs, a 30% decrease in average drilling time, and with lower rig moving costs. (Address before Annual Meeting of American Association of Oilwell Drilling Contractors at Denver, Colorado, October, 1962.)

MULTI-WELL CONTRACTS CAN SAVE MONEY

The industry is not taking full advantage of letting multi-well drilling contracts. If work is let on a larger scale, a contractor can work more cheaply by spreading his moving and overhead costs over several wells. Field development programs also are ideal opportunities in which to design cost-saving well programs discussed in preceding paragraphs. A surprising amount of money can be saved through proper planning of multi-well programs.

A north Oklahoma area constitutes an outstanding example of reduced drilling costs through properly planned multi-well contracts and specially designed programs. Locations were planned ahead. All preliminary site work, including water and fuel lines, was done in advance of moving the drilling rig to the location. Drilling of rat holes was eliminated. Surface casing was set with cable tools. When rotary tools moved to the location drilling started with a minimum of lost time. In a five-year period about 300 rig moves were made. By skidding instead of tearing down, more than 3,000 hours were saved.

In addition, drilling time was reduced through use of more weight, better bit programs, and not mudding up until just before starting coring operations. Coring time was reduced through use of longer core barrels and cutting full-gauge cores.

This program resulted in a 40% decrease in previous rotating hours, and a 60% decrease in average rotary time per well. The over-all result was to reduce drilling costs by more than one-third, despite increased labor and material costs.

CONTINUITY OF WORK IMPORTANT

Contrasted with the foregoing orderly and thoroughly planned north Oklahoma well program, twice within recent years 20 to 30 additional rigs have been suddenly put to work on a large Texas lease. In both instances, the number of rigs involved resulted in many rigs moving long distances to and from the ranch for only a relatively short period of work. Exclusive of hourly charges for erection and dismantling, the Texas oil field mileage charge for moving 750,000 lbs. of machinery 100 miles is $3,500.00. Think of the thousands of miles involved in the multi-rig moves in this particular instance.

Drilling activity now fluctuates widely. It is commonplace to see a variation in active rotary rigs of 300 to 400 each year, or 25-30%. Idle rigs cost money. Investment charges and overhead are continuing expenses, whether rigs are busy or idle. If there were less seasonal fluctuations in drilling levels, fewer rigs would be required to fulfill operator needs.

LOW BID VS. TOTAL WELL COSTS

A common fallacy today is the blind acceptance of the lowest footage bid without regard to the caliber of the rig or the drilling program. This can become a trap. It had best be replaced by a more realistic approach. Acceptance of the lowest bid completely disregards that the contractor's bill is not the only cost involved in drilling a well. The over-all well cost is the important consideration.

Henry Kerr, writing in the September, 1963, issue of Drilling International, has cited the following example on offsetting wells:

Bid:	Contractor A	Contractor B
Contract Price Per Foot .	$ 5.50	$ 5.00
Daywork with Pipe	1,200.00	950.00
Daywork without Pipe . . .	1,125.00	875.00

With a smaller rig, Contractor B had lower rig operating costs. Accordingly, Contractor B had bid both a lower price on both footage and day-work. Obviously, Contractor A would receive $55,000 for footage work, $5,000 more than Contractor B. It would appear Contractor B would have lower day-work charges also, and this proved true, although Contractor A spent 3 less days on daywork.

The two contractors rendered bills as follows:

	Contractor A	
Contract Price	10,000 ft.	$55,000
Daywork with Pipe	6 days	7,200
Daywork without Pipe . . .	3 days	3,375
Total Charge		$65,575

	Contractor B	
Contract Price	10,000 ft.	$50,000
Daywork with Pipe	9 days	8,550
Daywork without Pipe . . .	3 days	2,625
Total Charge		$61,175

So far, so good. Total charges by Contractor B were less than those of Contractor A, but not by as
So far, so good. Total charges by Contractor B were less than those of Contractor A, but not by as
great a margin as the bid figures seemed to indicate.

But what about other costs:

		Contractor A		Contractor B
Mud @ $300/day above 7,000 ft. .	15 days	$ 4,500	19 days	$5,700
Mud @ $700/day below 7,000 ft. .	25 days	17,500	36 days	25,200
		$22,000		30,900
Operator Overhead @ $75/day . .	40 days	$ 3,000	55 days	$ 4,125
Contractor Charges		65,575		61,175
Total Well Cost, excluding equipment, logging cementing		$90,575		$96,200
Cost per Foot		9.06		9.62

Time is almost as important a cost item for operators as for contractors. Despite Contractor B's "cheaper" bid, this well wound up costing $5,625 more than the well drilled by Contractor A, or 56 cents more per foot.

The foregoing figures point up the need to do more than take the low contractor bid. Be sure the rig hired is adequate for the particular well to be drilled. But, don't go overboard on size; excessive horsepower and pump capacity cost money and must be needed to be economical. You don't hire a 20-ton truck when a 12 or 15-ton is ample for the job. What about the contractor's history of performance, especially drilling time? Remember the importance of time on operator costs.

EXCESSIVE BIDS ARE EXPENSIVE

There is a growing practice of requesting an excessive number of bids. As many as 40 bids on a single well have been known. This practice adds greatly to the expenses of contractors and increases producer drilling costs.

Preparation of bids takes time, manpower and money. Few contractors will bid without inspecting the location, ascertaining road conditions, bridge load limitations, existence of low underpasses, availability of fuel and water, examining bit records, determining possible lost circulation troubles, etc. These functions frequently involve trips for one or two men, long distance calls, and consume much time.

Estimates on the cost of preparation of drilling bids average around $200.00 each. If a contractor succeeds in getting one bid out of every 10 he submits, the only way he has of recovering this $2,000.00 out-of-pocket expense is to include it in the prices he bids. This contractor must add 20 cents per foot to the price of a 10,000 ft. contract to recover this $2,000.00 bidding expense.

Contract bid expense runs into millions of dollars yearly for the whole producing branch of the U. S. petroleum industry. The question of whether a large number of bids is needed should be given careful consideration by producers. Promiscuous use of this practice adds greatly to the cost of drilling wells.

BETTER BID SPECIFICATIONS NEEDED

There is another way to reduce the cost of bids. The importance of operators furnishing contractors with good, detailed specifications when requesting bids cannot be over-emphasized. The expense of making an intelligent bid is increased when incomplete information is provided by operators. Contractor requests to operators for more information will take up both operator and contractor time. Time lost by supervisory contractor and operator personnel is an expense to both.

In preparing to drill a well, operator personnel has spent much time on exploration, geological and engineering information. From these data, operators can provide valuable data on formation characteristics that would indicate the possibilities of hard-to-drill, cavey, lost circulation, crooked hole, and high pressure zones. If furnished this information by operators, each contractor submitting a bid will not be duplicating the efforts of other contractors.

Unknown requirements cannot be evaluated accurately, forcing contractors to include possible contingencies in cost estimates. Operators should specify the proposed mud program, the logging program, the coring program, the casing program, as well as any type of special tools and hook-ups that will be required of the contractor. All these phases influence drilling rates and drilling costs.

If such information can be furnished by operators, it will reduce contractor cost of gathering bid information and result in more intelligent bids. Also, fewer disagreements would arise.

PAYMENTS ON REIMBURSABLE CHARGES

In recent years, more and more producing firms have engaged in the practice of having contractors handle an increasing number of reimbursable third-party charges. This practice transfers additional bookkeeping and record keeping costs from operators to contractors, without over-all savings.

Such reimbursable charges for materials and services can easily and quickly run into a large sum of money on every well a contractor drills. The tying up of $30,000 to $40,000 per well in reimbursable charges is not uncommon in many deep areas. The amount, of course, varies in different areas and by the requirements of producers.

SLOW PAYMENT IS A PROBLEM

The situation is aggravated in many instances by slow payment of both reimbursable charges and contract footage statements. This can become a heavy drain on the cash resources of a contractor.

If a contractor gets $30,000 per well tied up in five wells, he is out $150,000.00. In addition, the contractor has had to pay his labor, fuel and other expenses. But it is only after the contractor has drilled the last inch of hole and completed the well that he is entitled to his income from footage and perhaps daywork. It is not fair to add the burden of banking reimbursable third-party charges to his other current out-of-pocket bills.

Many contractors are finding slow payment of reimbursable charges and contract fees ties up so much capital funds they are forced to constantly borrow money to pay their current bills and labor. Borrowing necessitates the expense of paying interest. Contractors must add this expense to their bids.

Prompt payment of contractor invoices would help reduce drilling costs. Improperly prepared invoices sometimes cause slow payment. Contractors deal with many operators, and the preparation of invoices satisfactory to all operators can be a problem. Standardization of two or three accepted invoice forms would save numerous man hours of invoice preparation.

CONTRACTUAL RESPONSIBILITIES IMPORTANT

It is an outright mistake for producers to suppose contractors, because they operate on a fixed contract basis, can furnish additional services and assume additional risks without increasing expenses to producers. This is not true. Contractors necessarily must include cost allowances for these factors in their bids.

Ultimately, producers must pay for all drilling and workover costs of the contractor. The contractor has no other sources of income to compensate for his services.

Much has been said about operator rating of contractors. Operators also are rated by contractors. Operators who deal fairly and assume their fair share of drilling risks will get their drilling at fairer prices.

Many drilling contracts in use today contain broad hold-harmless and Mother Hubbard clauses, under which contractors assume unreasonable risks -- even to the extent of being responsible for the actions of operator personnel. Operators who write tough contracts pay a premium for their work. Contractors must seek expensive insurance protection and costs rise accordingly.

Use of either the standard API or AAODC drilling contract would help. It is difficult for contractors, working for many firms, to correctly interpret the intent of the many clauses contained in individual contracts. Through repetitious use of standard contracts both operators and contractors would come to know the placement of responsibilities. This would reduce the time-consuming study contractors must make each year of many contracts and substantially decrease instances of misunderstanding and uncertainty.

UNNECESSARY CEMENT TIME

Considerable savings can be achieved by a realistic reappraisal of the length of time to wait on cement. Some contracts continue to require 48 hr. of cement waiting time on surface strings, although others are experiencing no difficulties when waiting only 24 hr. for surface string cement to set.

Likewise, some contracts continue to call for 72 hr. waiting-on-cement time for production strings, although others find 48 hr. is adequate. It is known that temperature increases with depth and that cement sets faster with increasing temperature. Nevertheless, many contracts specify longer waiting-on-cement time on deep strings than on shallow strings.

Some companies have reduced waiting-on-cement time as much as three days, by allowing 24 hr. on surface strings and 48 hr. on production strings in place of 48 hr. and 72 hr. respectively. Three days saved on a rig which costs $750.00 per day means an over-all saving of $2,250.00 or 30 cents per ft. on a 7,500 ft. well. The saving of just one day on a $1,200.00 per day rig is equivalent to 10 cents per ft. on a 12,000 ft. well.

In this connection, operators should realize that there is no free time in drilling contracts. Contractors must figure this time in their drilling costs. So, do not ask for more so-called free time than will probably be used.

LARGER SURFACE CASING IS GOOD INSURANCE

The tendency today in many areas is to set 8-5/8 in. casing rather than 10-3/4 in. casing as surface pipe. Obviously, this represents a reduction in the cost of pipe. However, the reduction in cost of pipe is so small, there is considerable doubt whether a reduction is achieved in over-all costs.

If hole difficulties are encountered, the 10-3/4 in. pipe provides many advantages and possible savings which will far exceed the small difference in cost of pipe. Intermediate pipe can be run if desired and fishing is facilitated since the hole can be reamed out to 9 in. or even 9-7/8 in.

In many instances, these advantages result in more economical holes in the long run.

UNREALISTIC MUD SPECIFICATIONS

The mud program deserves a great deal of consideration. It is an area which influences the costs of both contractors and operators. It also is an area where cooperation and proper planning can reduce costs.

Although it is well known that mud programs have a tremendous effect on penetration rates, many operators do not give due consideration to this factor. Less time spent drilling a well usually means the use of fewer bits, a higher ratio of rotating hours to total time, and reduced mud expense. A good mud program is one designed to accomplish what the operator wants without retarding the contractor's ability to make hole. A slightly more expensive mud which enables the contractor to drill faster may reduce drilling costs sufficiently to result in lower over-all well costs.

Offset wells have been drilled with mud bills of $7,000.00 and $2,000.00. Both holes were serviced by reliable mud companies, both proved satisfactory for drill stem testing and logging, the difference of $5,000.00 being due to the requirements of two different operators.

Here is an example of the savings for operator and contractor made through a change in the mud program in one field:

66 less rotating hours @ $50/hour .	$ 3,300.00
30 less tripping hours @ $50/hour .	1,500.00
5 less bits	1,900.00
Mud cost	17,000.00
TOTAL SAVINGS PER WELL	$23,700.00

Direct contractor savings were $6,700.00 in addition to $17,000.00 mud savings. On these 6,500 ft. wells, this meant a reduction of $3.64 per foot.

BULK MUD REPRESENTS LARGE SAVINGS

The over-all size of the savings made through the use of bulk mud is not generally appreciated in the industry. Too often only the economies to the mud company and operator are considered, not realizing that the drilling contractor also eliminates costs with bulk mud.

On some locations, as much as 20% of the contractor's crew time is spent mixing sack mud. This involves one roughneck per tour. These costs can be eliminated through the use of bulk mud.

REASONABLE DEVIATION LIMITS

Unreasonable and arbitrary limitations on vertical deviation often drastically reduce penetration rates without providing any benefits. A reasonable attitude toward this problem can achieve sizable savings in many instances. Actually, it is the severity of doglegs or hole angles that give both contractors and operators trouble. Directional holes have proved that both contractors and operators can live with substantial over-all deviations from vertical if there are no sharp hole angles.

In this connection, contractors and operators should become familiar with the new deviation concepts in both the API and AAODC model contract forms. Under certain conditions well costs can be reduced by substantial amounts.

It is encouraging to see an increasing number of operators relaxing their deviation limitations. This is a move in the right direction, and sizable reductions in costs have been realized in some crooked hole areas.

IMPRACTICAL EQUIPMENT REQUIREMENTS

Some producers are demanding higher pressure pumps and greater horse-power rigs to an excess that goes beyond practical limits. Adequate pump pressure is a necessary prerequisite to fast penetration in some areas, but can be carried to such an extreme that penetration rates do not improve sufficiently to compensate for the enlarged investments and higher costs. The result is higher drilling costs instead of an economy.

A reasonable approach which weighs higher investment and operating costs against over-all results would benefit both operators and contractors. It does no good to increase penetration rates if the cost of achieving faster penetration more than offsets the saving in time.

Much has been written and said about the increased expenses caused by different producers requiring such a wide variety of blowout preventer hook-ups. Despite all the discussion, the problem is no nearer a solution today. There is no standardization even on a broad general basis. In some respects, the situation is getting worse. More companies are insisting on a highly individualized blowout preventer hookup.

Consequently, each year contractors spend large sums of money to meet the widely varied blowout equipment hookup requirements of different operators. Much of this equipment remains idle in a yard, except when a contractor is working for a particular operator.

There also is a tendency to require high pressure hookups when not needed. This results from rules too often being made to cover wide areas rather than localized conditions. Many operators require flanged valves of a particular type and size. In many areas wells can be controlled safely with 2 in. lines and valves instead of 3 in. or even 4 in. Most blowouts are the result of some factor other than the size of preventer or type of connection.

Excessive substructure heights increase the cost of drilling wells. The investment expense of high substructures is increased through additional trucking costs.

The desire to have surface casing flanges at ground level may require the use of a 14 ft. substructure, whereas by setting the surface casing flange 2 ft. below ground level a 10 ft. substructure would suffice.

There are many ways to reduce well costs. Let's resolve that contractor, operator and service-supply groups will look for every means of effecting savings, and put all advancements into universal practice.