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Application of Minimum Cost Drilling Programs

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ABSTRACT

Minimum cost drilling programs have been available for about 10 years, but only recently have they been utilized to any extent. One of the principal disadvantages of most programs is that they assume rig operating costs are independent of bit weights and rotary speeds. Although the use of minimum cost drilling programs is relatively new, their proper use can effect substantial savings in the drilling operation.

The principal uses of a minimum cost drilling program are in (1) planning the entire well, (2) selecting the proper bit, (3) optimum time to pull a bit, (4) proper weight and speed to meet special conditions, such as extending bit life in order to save a round trip, reducing bit life as a result of changing formations, critical rotary speeds and crooked hole conditions, (5) revising optimum bit weights, rotary speeds, and bit footages on an instantaneous basis during drilling and (6) studying special problems such as the influence of rig costs on optimum drilling conditions.

Minimum cost drilling programs can be economically used with a time-share computer and a teletype terminal. The terminal can be located at the rig or in the office.

Most minimum cost drilling programs in use today are more complex than they need to be. A relatively simple program should be used initially; then, as more experience is gained, the programs can be made more complex.

References and illustrations at end of paper.

INTRODUCTION

Since the late 1950's, as evidenced by the published petroleum literature, there has been a strong interest in developing mathematical relationships which would describe and, therefore, permit some type of optimization of the drilling operation. Beilstein and Cannon[1] made an important contribution to understanding the interrelationships of some of the more important variables affecting the economics of drilling. Speer[2] later published valuable data which largely supported the observations of Beilstein and Cannon. Within a short period of time a number of analytical methods for describing the drilling operation were published.[3-7] All of these methods were developed primarily to study the effects of varying bit weights and rotary speeds on penetration rates and drilling costs. These analytical methods are now commonly referred to as minimum cost drilling or optimized drilling methods. A true minimum cost drilling program must include all variables influencing the drilling operation. Some of the most important of these variables are (1) drilling rig, (2) crew efficiency, (3) hydraulics programs, (4) type of mud, (5) bit selection, (6) bit weight and (7) rotary speed. There are numerous other factors which could be included. However, it is the purpose of this paper to discuss the practical application of the optimum weight and speed techniques, which are commonly referred to as minimum cost drilling programs.

All of the published minimum cost drilling techniques are basically very similar. They use two principal types of equations: (1) a penetration rate equation and (2) a bit life equation or equations. The various published methods may appear to be substantially different, because they use different terms and varying numbers of terms to describe the various formation, drilling fluid, and drilling bit parameters necessary for the basic equations.

INFLUENCE OF VARYING WEIGHTS AND SPEEDS ON COSTS

All but one of the published minimum cost drilling techniques assume that rig operating and maintenance costs do not increase with increasing rotary speeds and bit weights. This is considered to be a serious limitation since it is a well established fact that higher bit weights and rotary speeds do increase operating costs. Probably one of the principal reasons for failure to include this type of data in most minimum cost drilling programs is the scarcity of information. Admittedly, this is very difficult information to obtain; nevertheless, any reasonable approach should be better than completely to ignore the problem.

Varying bit weights and rotary speeds will affect the following: (1) drill-pipe maintenance, (2) drill-collar maintenance, (3) rig maintenance and (4) wire-line maintenance. Although it is not the purpose of this paper to present the development of a minimum cost drilling equation, the development of one set of cost data, the drill-pipe maintenance equation, will be shown to illustrate the method of development.[6] Drill-pipe maintenance was assumed to be principally a function of rotary speed and length of drill pipe in the hole. For simplification it was assumed that, over the normal operating range of rotary speeds and depths, the equation would be a straight line of the following form.

$$M_{dp} = B \cdot N \cdot L_{dp} \quad \ldots\ldots\ldots\ldots \quad (1)$$

where M_{dp} = drill-pipe maintenance, \$/hr
B = constant
N = rotary speed, rpm
L_{dp} = length of drill pipe in the hole, ft

Available data for one contractor showed the cost of maintaining drill pipe to be $1\frac{1}{2}$¢/day/ft of drill pipe when rotating at an average rotary speed of 85 rpm. Assuming that Eq. 1 passes through the origin, the resulting straight-line equation is

$$M_{dp} = 1.102 \times 10^{-5} \cdot N \cdot L_{dp} \quad \ldots\ldots \quad (2)$$

During recent years, data from other rigs have been used to develop drill-pipe maintenance equations for the particular rigs using the minimum cost drilling program.

USING AN MCD PROGRAM

The variables involved in the drilling operation are so complexly interrelated that all of the minimum cost drilling programs available today must be considered as only a first step in the proper direction. As experience is gained with these programs, it is expected that the equations will be modified to more properly reflect the relationship of the variables. However, it has been well documented that the minimum cost drilling programs currently in existence can still effect substantial cost reductions in drilling operations.

With currently available information, the most practical way to use a minimum cost drilling program is to install the program on a time-share computer service with a teletype terminal located in the office or on the rig. An ordinary telephone line is all that is needed to connect the teletype terminal to the time-share computer. The costs of using a minimum cost drilling program in this way are quite nominal. The total computer costs of completely preprogramming a typical 15,000-ft well will be about \$15. After a well is started and a specific formation is being drilled, the tool pusher can call his office with a set of data (bit weight, rotary speed and drilling rate). Within 2 or 3 minutes a revised set of optimum drilling conditions can be obtained with the teletype terminal and the results given to the tool pusher. The total computer-related costs for this information will be just a few cents. Thus, it is apparent that it is practical and economical to use a minimum cost drilling program. The reason that these programs have not been used more extensively is that qualified personnel have not been available. Before these programs can be effectively applied, it is necessary that the user completely familiarize himself with the limitations, as well as the uses of his minimum cost drilling program. All minimum cost drilling programs have limitations, and the best way to become aware of these limitations is to use the program on several wells which have already been drilled and on which good information is available. For example, one of the limitations of most minimum cost drilling programs is that they cannot determine when the calculated drilling rate is too fast. For example, in soft formations, if no restraints are placed on the limits of the variables, the minimum cost drilling program might show that minimum cost occurred at a weight and speed which produced a penetration rate of 200 ft/hr. This high penetration rate may exceed the capacity of the rig, crew, and circulating system; and, therefore, is unreasonable. The user must recognize this and place some penetration rate restrictions on the program results. One simple method of overcoming this problem is to have the computer print several possible weight and speed combinations, not just one optimum. This permits the user to select the best combination of weight and speed after taking other factors into consideration, which the computer program will not do at the present time.

It can be assumed that all rigs normally operate at optimum conditions to the best of the operators' abilities. In most areas, these operations are probably near the actual optimum. Therefore, dramatic decreases in drilling costs cannot be expected from the use of a minimum cost drilling program. However, even small decreases in costs can be significant.

In order to use a minimum cost drilling program it is necessary to have complete offset bit records. It is desirable to have an electrical log so that the bit records can be correlated with the formations they have drilled. This is all the information that is actually required to run the minimum cost drilling program. A drilling time record is quite useful, particularly when one bit has drilled more than one type of formation.

Most minimum cost drilling programs calculate weight and speed conditions which will produce the minimum cost per foot for the formation being drilled. This is normally not the best solution. It is generally preferable to determine the weight and speed conditions which will drill a given interval at minimum cost. This given interval may span the entire bit footage. This aspect becomes quite important when lithologies change frequently, as is usually the case.

The principal uses of a minimum cost drilling program are as follows:

1. calculating total costs and total time, including rotating hours, for the entire well,

2. determining optimum weights and speeds to drill a given interval,

3. comparison of the economics of various types of bits, i.e., conventional tooth bits vs insert bits,

4. determining optimum time to remove a bit,

5. determining optimum weights and speeds to meet special conditions encountered during drilling,

a. extending bit life a few extra feet in order to drill to total depth and save a round trip,

b. shortening bit footage in order to change to a different type bit when a different formation is expected,

c. selecting the best combination of weight and speed when critical rotary speeds may dictate a revision of the calculated optimum conditions,

d. selecting the best combination of weight and speed when crooked hole conditions dictate bit weight reductions,

6. revising, on an instantaneous basis, the optimum weight, speed and bit life for a given interval being drilled and

7. studying other problems related to the drilling operation,

a. determining the effect of rig costs on optimum weights and speeds, i.e., \$70/hour land rig vs \$700/hour offshore rig.

SELECTING THE PROPER BIT

Table 1 shows typical output data for one interval. This table shows how the minimum cost drilling program can be used to determine the influence of bit type on drilling costs. In this example a uniform lithologic interval having a thickness of 650 ft is encountered at a depth of 11,500 ft. The only changes in input data to the computer program from Case A to Case B is that bit costs have been changed from \$250 for the conventional tooth bit to \$1,290 for the insert bit. Since the two bits have different drillability and bit life constants, these two parameters were also changed. Table 1 shows that it would be more economical to use insert bits to drill this interval. This, of course, is not always the case. On a well recently drilled in West Texas, where a comparison was made of the economics of insert vs conventional bits, the use of insert bits appeared to be considerably more costly. This of course is one of the significant advantages of a minimum cost drilling program. The well can be "drilled on paper" before it is actually drilled, and the influence of variables can be studied in order to effect maximum savings.

INFLUENCE OF RIG COST ON OPTIMIZATION

Table 2 shows the influence of rig cost on optimization. In both cases, an interval having a thickness of 2,000 ft, topped at 7,000 ft, is to be drilled. Case A is for a land rig costing about $70/hour. For the land rig the optimum condition is to use nine bits to drill the interval. The optimum weight and speed to produce minimum costs is 56,000 lb and 185 rpm. For the offshore rig, costing about $700/hour, the optimum condition is to use 11 bits to drill the interval, with a bit weight of 66,667 lb and a rotary speed of 202 rpm. The high rig cost has caused a significant change in the optimum drilling conditions. The use of studies, such as those shown in Table 2, are quite useful in assisting personnel being moved from land drilling conditions to remote or offshore drilling locations to become more familiar with the new economics involved.

ADVANTAGES OF MULTIPLE PRINT-OUTS

The use of multiple print-outs, showing the costs for various combinations of bit footages, weights and rotary speeds, has a number of advantages for the user. For example, referring to Case A of Table 2, it is noted that the cost of using 10 bits to drill the interval with a weight of 61,333 lb and a rotary speed of 195 rpm is only slightly greater than the previously mentioned optimum conditions. This would, however, require an extra bit and an extra round trip. Or, again referring to Case A of Table 2, the rig operator might choose to increase his calculated per-foot costs slightly and use eight bits to drill the interval with the lower weight of 50,667 lb and the lower rotary speed of 175 rpm. It should be remembered that the minimum cost drilling program does not evaluate a number of the risks associated with the drilling operation, two of which are the hazards involved in making a round trip and the hazards involved in leaving the bit in the hole for a longer period of time. Thus, having the results of multiple conditions permits the rig operator to use his own judgment in selecting the proper optimum for his specific problems.

Another important advantage of having print-outs of several combinations of weights and speeds is that many rigs have very limited capabilities for varying rotary speed. These print-outs permit the operator to select the rotary speed dictated by his rig, but at the same time it will show him how much this lack of flexibility is costing and, thus, may encourage him to increase his rig's rotary speed flexibility.

PLANNING THE WELL

One of the major problems with using a minimum cost drilling program for planning the well is that offset bit records are used to supply the necessary formation drillability and bit life constants. Since these data are seldom complete and are often suspect, it may be desirable to develop three complete sets of data for each interval drilled when planning a complete well program. Set 1 will use the data which appear to be average. Set 2 will use a set of data having faster than average penetration rates, and Set 3 will use a set of data having slower than average penetration rates. All three sets of results are given to the rig. Then, as each interval is encountered during the actual drilling operations, the rig supervisor can use that set of data which most accurately describes the drilling situation as it is encountered. This method requires a minimum amount of instantaneous revision of the minimum cost drilling program results while the well is being drilled.

Table 3 shows the print-out of two sets of results furnished the contractor in advance of a well recently drilled in Oklahoma. One set of data shows results from the minimum cost drilling program by using weights and speeds similar to those used on a well previously drilled in the area. The other set of data shows the results to be expected by using more nearly "optimum" weight, speed and bit life combinations. In addition to this summary, a set of detailed computations for each interval, similar to those shown in Tables 2 and 3, were also supplied to the contractor. As shown in Table 3, the indicated savings by using the more nearly optimum conditions are substantial.

USING THE PROGRAM WHILE DRILLING

One of the major benefits to be obtained from the use of a minimum cost drilling program is the determination of optimum weights and speeds during the course of drilling. This eliminates much of the need for reliance on offset bit records, as the formation drillability and bit life constants are obtained from drilling data (i.e., weight, speed, penetration rate). The only other parameter needed is bit footage and this must be estimated from an evaluation of the best available data. Using time-share computers and a teletype terminal, the updated information can be developed within 2 or 3 minutes. This can often be accomplished by a telephone call to the company office where the teletype terminal is located. Of course, if a telephone is available at the rig, the teletype terminal can be located at the rig. The teletype terminal is about the size of an ordinary typewriter and can be purchased for less than $2,000 or rented on a maintenance-type contract for about

$80 per month. As previously mentioned, the computer costs for revising the optimum drilling conditions are usually less than $1.00. Thus, the cost of obtaining the updated information is minimal.

The most important costs involved in the use of this type of minimum cost drilling program is that an engineer must be trained to use and understand the program. In many cases this limits the contractor's use of the program. In order to utilize the program properly, the user must work with the program on a routine basis. It is not possible to properly apply the program if, after the initial indoctrination, the user devotes only a few minutes every month to the program. In such a case, the use of the program will result in answers which are misunderstood and misapplied. Therefore, if a minimum cost drilling program is to be used, manpower must be available to utilize the program properly.

COMPLEXITY OF PROGRAMS

Minimum cost drilling programs are still in the early stages of development. As these programs are used more and more, the analytical solutions will be revised to describe more nearly the actual mechanics of drilling. The equations used in all minimum cost drilling programs are empirical in nature, and as more experience is gained from their use, the equations will undoubtedly be improved. However, the equations used in today's programs are sufficiently accurate that improvements in the drilling operation can be made if they are properly utilized.

One of the principal disadvantages of some of the minimum cost drilling equations in use today is that there are so many empirical constants required that it becomes quite difficult to evaluate the significance of these constants so that improvements in the quality of the equations can be made. A critical evaluation of the sensitivity of parameters in some minimum cost drilling equations shows that some of these constants could be combined to produce a simpler equation. With the present state of the art in application of minimum cost drilling programs, it is preferable to use a relatively simple group of equations. Then, as experience is gained with their use, the equations can be made more complex. Progress should be from the simple to the complex, not vice versa.

CONCLUSIONS

Minimum cost drilling programs have been available for about 10 years, but only recently have they been used to any large extent. One of the principal limitations of most programs in use today is they assume that increasing bit weights and rotary speeds will not increase rig operating costs.

It has been proved that the proper application of minimum cost drilling programs will reduce drilling costs. These programs can be used in the following ways: (1) plan a drilling program for a well (i.e., select optimum weights, speeds, bit types and bit footages for each lithologic unit to be drilled), (2) update, on an instantaneous basis, the optimum conditions during the actual drilling of the well and (3) evaluate specific drilling problems, such as optimum time to remove a bit, effects of rig costs on optimum weights and speeds, and determining best practices when conditions such as critical rotary speeds or crooked hole conditions exist.

It is very desirable to have the computer print out several combinations of weights, speeds and bit footages for each interval to be drilled. This provides the rig operator with more flexibility in setting his rig operations to approach, as much as possible, the minimum cost situation.

The time-share computer is ideally suited to the use of minimum cost drilling programs, as the cost of using the computer is nominal, and the connecting teletype terminal can be located at the rig or in the office.

Minimum cost drilling programs are still in their infancy. Some programs are probably more complex than they need to be at the present time, since all of them are based on empirical relationships. The simplest program possible should be used and, as experience is gained with its use, it can be made more complex to describe the drilling operation more accurately.

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Table 1 - Effect of bit type on drilling costs.[1]

Depth = 11,500 Feet; Interval Thickness = 650 Feet

Case A: Conventional Tooth Bit (Bit Cost = $250):

WEIGHT	SPEED	$/FT[2]	ROTATING HR	LINE
BIT FOOTAGE=	72.2 FOR EACH OF		9 BITS	
40000.	202.	23.49	13.97	45
53333.	127.	22.24	13.19	46
66667.	89.	21.54	12.61	47
80000.	67.	21.12	12.16	48
BIT FOOTAGE=	65.0 FOR EACH OF		10 BITS	
48000.	186.	22.40	10.91	49
58667.	135.	21.70	10.48	50
69333.	103.	21.26	10.13	51
80000.	82.	20.98	9.85	52
BIT FOOTAGE=	59.1 FOR EACH OF		11 BITS	
53333.	190.	22.01	8.83	53
61333.	152.	21.59	8.58	54
69333.	125.	21.30	8.38	55
80000.	100.	21.05	8.14	56

Case B: Insert Bit (Bit Cost = $1,290):

WEIGHT	SPEED	$/FT[2]	ROTATING HR	LINE
BIT FOOTAGE=	650.0 ENTIRE INTERVAL		1 BIT	
18667.	61.	15.98	121.24	1
BIT FOOTAGE=	325.0 FOR EACH OF		2 BITS	
21333.	198.	12.02	29.51	2
29333.	119.	11.34	27.69	3
37333.	81.	10.94	26.39	4
48000.	54.	10.60	25.09	5
BIT FOOTAGE=	216.7 FOR EACH OF		3 BITS	
37333.	182.	11.66	11.73	6
50667.	111.	11.33	11.03	7
64000.	77.	11.16	10.53	8
80000.	54.	11.05	10.07	9
BIT FOOTAGE=	162.5 FOR EACH OF		4 BITS	
50667.	198.	13.02	6.21	10
58667.	157.	12.93	6.03	11
69333.	120.	12.86	5.83	12
80000.	95.	12.83	5.66	13

BIT LIFES/INTERVAL, TO INVESTIGATE ?-2

TWO NEW LIMITS OF BIT WEIGHT FOR STUDY ? 40000, 55000

40000.	72.	10.84	26.02	14
42667.	65.	10.75	25.69	15
48000.	54.	10.60	25.09	16
53333.	46.	10.47	24.57	17

1. This is typical output from a time-share computer.

2. These are total drilling costs.

Table 2 - Effect of rig cost on optimization.

Depth = 7, 000 Feet; Interval Thickness = 2, 000 Feet

Case A: Land Rig (Rig Cost = $70 Per Hour):

WEIGHT	SPEED	$/FT	ROTATING HR	LINE
BIT FOOTAGE=	250.0 FOR EACH OF 8 BITS			
50667.	175.	4.61	12.20	20
56000.	125.	4.89	13.94	21
64000.	80.	5.36	16.66	22
72000.	54.	5.88	19.49	23
BIT FOOTAGE=	222.2 FOR EACH OF 9 BITS			
56000.	185.	4.53	9.42	24
64000.	119.	4.88	11.25	25
72000.	80.	5.26	13.16	26
80000.	56.	5.67	15.15	27
BIT FOOTAGE=	200.0 FOR EACH OF 10 BITS			
61333.	195.	4.54	7.48	36
66667.	147.	4.72	8.36	37
72000.	114.	4.91	9.27	38
80000.	80.	5.88	10.66	39

Case B: Offshore Rig (Rig Cost = $700 Per Hour):

WEIGHT	SPEED	$/FT	ROTATING HR	LINE
BIT FOOTAGE=	222.2 FOR EACH OF 9 BITS			
56000.	185.	37.22	9.42	110
64000.	119.	42.65	11.25	111
72000.	80.	48.32	13.17	112
80000.	56.	54.20	15.15	113
BIT FOOTAGE=	200.0 FOR EACH OF 10 BITS			
61333.	195.	35.73	7.48	114
66667.	147.	38.71	8.36	115
72000.	114.	41.77	9.27	116
80000.	80.	46.51	10.67	117
BIT FOOTAGE=	181.8 FOR EACH OF 11 BITS			
66667.	202.	34.93	6.09	118
69333.	178.	36.19	6.41	119
74667.	139.	38.77	7.08	120
80000.	110.	41.41	7.76	121

Table 3 - Calculated drilling program, XYZ Unit 1, summary.

	Depth From Feet	Depth To Feet	Optimum Weight Pounds	Optimum Speed RPM	Number of Bits	Feet Per Bit	Total Rotating Hours	Cum. Rotating Hours	Total $/Ft.	Cost $
	0	3900	SURFACE HOLE				95	95		
1	3900	7000	65,000	142*	9	344	82	177	3.29	10,200
2	3900	7000	65,000	79	8	388	132	227	4.25	13,200
1	7000	9500	65,000	146*	12	208	107	284	5.66	14,200
2	7000	9500	69,000	66	10	250	176	403	7.18	18,000
1	9500	11,500	73,000	139*	7	286	51	335	3.96	7,900
2	9500	11,500	77,000	61	6	333	92	495	5.05	10,100
1	11,500	13,900	100,000	42	25	96	300	635	15.58	37,400
2	11,500	13,900	77,000	61	24	100	336	831	16.30	39,100
1	13,900	16,000	35,000	56	12	175	233	868	12.98	27,300
2	13,900	16,000	27,000	54	9	232	306	1137	14.30	30,000
								Totals	(1)	97,000
									(2)	110,400

*NOTE: If these rotary speeds are too high, refer to the tables for other combinations of weight and speed which will produce similar results.

(1) Recommended program for XYZ Unit No. 1, using Minimum Cost Drilling Program

(2) Results from MCD Program using weights and speeds similar to those used on ABC No. 1