OPTIMIZING BIT HYDRAULICS

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ABSTRACT

A method is presented for optimizing roller cone bit hydraulics programs to provide minimum cost per foot drilled. The method differs from traditional optimization techniques in that optimum pump operating conditions are determined rather than being arbitrarily imposed as a constraint on the optimization process. The method considers rate of penetration (ROP) response to increased bit hydraulic horsepower (BHHP) as well as increased fuel and pump maintenance costs to provide increased BHHP. Optimum conditions may be determined through a parametric analysis or by imposing simple relationships between pump fuel and maintenance costs and ROP response to increased BHHP.

Full scale laboratory drilling data under various overbalance pressure conditions are presented to demonstrate the relationship between ROP and BHHP. Laboratory and field results with blanked nozzles and asymmetric three nozzle configurations are also presented.

INTRODUCTION

Optimizing roller cone bit hydraulics has been a popular and somewhat controversial topic for many years. There is still no concensus of opinion on what parameter should be optimized to provide maximum ROP. Kendall and Goins[1] presented derivations which established criteria for maximizing BHHP, jet impact force and jet velocity within constraints imposed on pump horsepower and discharge pressure. Eckel[2] recommended maximizing a Reynolds number function associated with jet velocities based on laboratory results in microbit drilling studies which considered viscosity effects. McLean[3,4] suggested maximizing bottom hole cross flow velocity which is equivalent to the maximum jet impact force condition. Smalling and Key[5] concluded that maximum jet impact pressure on the formation explained observed effects of extended nozzles and blanked nozzles and is the key parameter in hydraulics optimization.

All of these proposed optimization criteria consider pump operating conditions to be fixed. That is, they seek to maximize ROP within prescribed constraints on flow rate, pump horsepower or standpipe pressure. It can be shown that BHHP and jet impact force have values within about 92 percent of their maximum values when either parameter is maximized. This is one reason why it has been difficult to prove the superiority of either condition or the closely related conditions of maximum cross flow velocity or impact pressure in field or laboratory drilling tests. In practice, any of these optimizing criteria can be expected to give good results. However, any of these criteria can result in poor bit hydraulics when effects of the pump operating constraints are ignored.

In an effort to assess the effects of standpipe pressure constraints on drilling economics, the authors introduced the concept of a hydraulics program designed to provide minimum cost per foot drilled[7,8]. This approach requires consideration of the following parameters.

(1) the increase in rate of penetration with increased bit hydraulics

(2) the increase in fuel costs to provide increased pump horsepower

(3) the increase in pump maintenance cost with increased pump horsepower and standpipe pressure

(4) the overall rig operating costs

This paper expands further on this optimization concept and derives an optimum condition using a new model for pump maintenance costs.

The new optimization approach may be thought of as a two step process in which optimum pump horsepower level and standpipe pressure conditions are first established, and then bit nozzle sizes and configurations can be selected to satisfy any of the traditional optimization criteria. A considerable body of data is building which suggests improved ROP can be obtained with blanked or asymmetric nozzle configurations. The experiments of McLean[2,3], Sutko and Meyers[9] and Sutko[10] suggested jet impact pressure and cross flow velocities at constant total bit impact force could be increased by blanking one or two nozzles. This suggests that impact force per nozzle should be maximized. Townsend[11] conducted laboratory drilling tests with two and three nozzles of constant total area and concluded two nozzles provided higher ROP for some formation and mud conditions. Warren and Winters[12] studied nozzle size and asymmetry on pressure distributions beneath the bit and correlated these effects with observed ROP trends. Doiron and Deane[7,8] also presented laboratory drilling data which support the conclusion that ROP can be improved with nozzle asymmetry. They presented data which indicate ROP is a function of BHHP per nozzle or jet impact force per nozzle. Some of these data are presented in this paper together with data of other authors to demonstrate observed relationships between ROP and bit hydraulics.

ROP RESPONSE TO BIT HYDRAULIC HORSEPOWER

Doiron and Deane[7,8] have presented full scale laboratory drilling data taken over a range of drilling conditions which fit the relationship

$$ROP = K\,(BHHP/nozzle)^b \qquad (1)$$

where K and b are empirical constants determined for a particular bit, formation and drilling condition. The BHHP is divided by the number of nozzles used in the bit to obtain BHHP/nozzle, a parameter which tends to correlate observed differences in ROP with two and three nozzle drilling. Generally, drilling with two nozzles will produce higher ROP than a symmetric three nozzle configuration at the same total BHHP when cutter balling is not a problem. As an example of these trends, the data of Figure 1 are replotted from reference 7 and compared to the model of equation (1). These data were obtained in laboratory drilling tests with a 7-7/8 inch diameter IADC 5-1-7 bit. Mancos shale core samples were drilled at 4000 psi overbalance pressure with a bit weight of 30,000 lb (3800 lb/in diameter) and 60 rpm. Data from four different rock samples and three different nozzle configurations (3-9's, 3-11's and 2-11's) are presented. The data provide a good fit to equation (1) with b=0.27. Data with 3-9's and 2-11's have the same total BHHP at a given flow rate since the total nozzle area is the same, but BHHP/nozzle is 50 percent greater for the 2-11 configuration and produces a higher ROP.

Warren and Winters[12] recently published results of a study on the effects of nozzle diameter on hydraulic cleaning and ROP with an 8-1/2 inch diameter IADC 6-1-7 bit. The ROP testing was conducted in Indiana Limestone at 5000 lb/in. of diameter

(42,000 lb) weight-on-bit, 75 RPM and 100 psi overbalance pressure. In the paper, they presented the effects of total jet impact force on ROP for three different nozzle diameters: 9/32, 13/32 and 15/32 inches. Their data are replotted in Figure 2 vs. BHHP/nozzle and are compared to a least squared error regression fit of equation (1) which yields b = 0.271. It is interesting to note that these ROP data plotted by Warren and Winters against total jet impact force fell onto three distinct curves with the smaller nozzle sizes giving better performance. However, when the data are replotted here versus BHHP/nozzle, the separation of the data is not so obvious and a single curve gives a good fit to all of the data.

Townsend[11] has also published laboratory data comparing two and three nozzle drilling for a 7-7/8 inch diameter IADC 5-2-7 bit. He studied two different formations (Indiana Limestone and Carthage Marble) with different mud systems at overbalance pressure ranging from 0-300 psi. The two nozzle configuration generally produced higher ROP, especially in more severe chip hold down situations with higher overbalance pressure and weighted mud systems. Some of Townsend's data taken in Indiana Limestone at 100 and 250 psi overbalance pressure are replotted in Figure 3 and compared to the model of equation (1). The bit weight was 31,500 lb (4000 lb/in) and rotary speed was 60 rpm. The dark data points in Figure 3 are for a two nozzle configuration and have the same total BHHP as the open symbol data points (three nozzle configuration) to their immediate left. The data provide an excellent fit to the model of equation (1) with increased BHHP/nozzle being more important at the more severe chip hold down condition of higher overbalance pressure.

Presented in Figure 4 are the results of testing done in the Reed Rock Bit Company pressure drilling facility using an 8-3/4 inch IADC 5-1-7 bit. The bit was tested at a constant bit weight of 3400 lb/in. of diameter (30,000 lb) and 700 psi overbalance pressure. Here, the effects of hydraulics and rotary speed on ROP were studied. As in the case of response to bit weight, the ROP response to increased rotary speed can be enhanced with improved hydraulics. In the range from 60 to 120 rpm the exponent b ranges from .29 to about .35. The relatively small change in the exponent between 90 and 120 rpm is probably a result of some bit balling occurring at the higher rotary speed, indicating a need for greater hydraulic horsepower levels at the higher mechanical energy levels. The darkened symbols of Figure 4 at 90 BHHP/nozzle represent data taken with a blanked nozzle. These data further confirm the observation made in reference 7 that ROP improvement with a blank nozzle can be correlated with BHHP/nozzle.

Figure 5 shows data from full scale laboratory drilling tests reported by Tibbitts et al[16]. The testing was conducted in Mancos Shale with a 7-7/8 inch IADC 5-3-7 bit at a variety of weights and speeds and with a constant overbalance pressure of 2000 psi. The replotted data shown in Figure 5 were obtained at constant bit weights of 3800 lb/in. of diameter (30,000 lb) and 5000 lb/in. of diameter (40,000 lb) and constant rotary speed of 60 rpm. Also shown are the data fits to equation (1) with the range of exponents again falling close to the nominal value of .3, b ranging from .326 to .337. The increase in the value of the exponent with increased bit weight is consistent with theories put forth in the literature that hydraulics become increasingly important as bit weight is increased.

Figure 6 presents further data relating BHHP/nozzle to weight on bit and ROP. The data are taken from SPE-11231 where Black et al[17] studied the effect of weight per inch of bit diameter on ROP. Their testing was done with four different bit sizes at varied conditions, but the data replotted in Figure 6 are for a 6-1/2 inch diameter IADC 5-3-7 bit drilling at constant rotary speed of 60 rpm with an overbalance pressure of 2000 psi in Mancos Shale. Because only two hydraulic conditions were run, the ROP data are plotted as a function of weight on bit at 22.5 and 42 BHHP/nozzle. The data show a marked improvement in ROP response to weight on bit at the higher hydraulic horsepower level, particularily at bit weights above 20,000 lbs or about 3000 lb/in. of diameter.

The reported data support the fact that BHHP requirements are not necessarily a function of only ROP, but also chip hold down and cutter balling phenomenon which can occur at very low ROP typical of high overbalanced deep drilling. The key issue for cost per foot savings is percentage change in ROP obtained with higher BHHP/nozzle rather than absolute changes in ROP.

When cutter balling is a problem with two nozzle drilling, an asymmetric three nozzle configuration can improve ROP by concentrating most of the BHHP in one or two nozzles. This effect is demonstrated by the data of Figure 7 where laboratory test results with a three symmetric nozzle configuration (9-9-9), an asymmetric three nozzle configuration (13-9-9) and a two nozzle configuration (0-11-11) are compared. A 7-7/8 inch diameter IADC 5-1-7 bit drilling Mancos shale at 4000 psi overbalance pressure was used to obtain these data. A constant bit weight of 30,000 lb (3800 lb/in) was used and rpm was varied from 60 to 270 rpm. The 0-11-11 data are shown in the rectangular box of Figure 3 and show no ROP improvement when rpm was increased from 180 to 270 rpm. Examination of the bit revealed that the blanked nozzle caused one cutter to ball up with cuttings due to lack of hydraulic cleaning. This problem was not observed when drilling with the 9-9-9 nozzle configuration denoted by the dark data points in Figure 7 which had the same total BHHP as the 0-11-11 configuration. In an effort to maximize BHHP/nozzle and retain the better cutter cleaning of a three nozzle configuration, an asymmetric 13-9-9 nozzle configuration was tested for comparison. This is a compromise to the extreme condition of blanking two nozzles, and the data are shown as the open symbols of Figure 7. The numerical values for the exponent b for the three different rpm conditions were obtained with the 9-9-9 and 13-9-9 data only; the 2-11 data were excluded from the fit because of the balled cutter problem. The curve fits indicate ROP is more responsive to increased BHHP/nozzle at higher rpm, a more severe cleaning condition due to less cleaning time between cutter impacts. The less sensitive response at 270 rpm compared to 180 rpm (b = .43 at 270 rpm vs. b = .51 at 180 rpm) is thought to be caused by some cutter balling at higher rpm and ROP conditions.

As a further indication of the potential application of asymmetric nozzles, Figure 8 presents data taken from a well in Matagorda County, Texas where an asymmetric nozzle configuration was compared to a more conventional symmetric nozzle arrangement. Five 9-7/8 tooth bits (IADC 1-1-1) with symmetrical nozzles were required to drill the interval of interest between approximately 8000 and 10,000 feet. At a depth of 10,243 ft, stuck pipe required plugging the well back to 6000 ft and side tracking the hole. Between about 7500 ft and 10,000 ft in the sidetracked hole, bits identical to ones used in the initial drilling of this depth interval were used with an asymmetrical nozzle arrangement of two large and one smaller nozzle. Nozzles were selected to provide similar total BHHP used on bits in the initial hole at this depth, and similar flow rate and standpipe pressures were used. Similar bit weight and rotary speeds in the range of 40,000 lb and 150 rpm were also used. ROP as a function of depth-out for each bit run is plotted in Figure 4 and the nozzle configuration used is labeled for each data point. ROP with the asymmetrical nozzle arrangement was superior at each depth with an average 28 percent improvement over the symmetrical nozzle arrangement.

OPTIMIZING HYDRAULICS FOR MINIMUM COST PER FOOT

The following equation relating drilling cost per foot at two different hydraulic conditions was derived in reference 7.

$$\frac{DC_2}{DC_1} = \left[1 + \frac{F_2 - F_1}{R_1} + \frac{PPC_2 - PPC_1}{R_1}\right]\left[\frac{ROP_1}{ROP_2}\right] \quad \ldots\ldots\ldots\ldots\ldots \quad (2)$$

where DC_i is drilling cost per foot, F_i is hourly fuel cost to power mud pumps, PPC_i is average hourly cost for expendable pump parts, R_i is total rig operating cost per hour and i denotes hydraulic operating condition 1 or 2. The bit and trip costs normally appearing in cost per foot equations have been ignored for simplicity since these costs are assumed to be the same for either condition. Equation (2) describes the cost per foot ratio for equal bit life in hours or footage for the two operating conditions. The equation does not account for lost drilling time due to pump failures. When operating pumps near their rated capacity, more frequent replacement of pump parts should be anticipated and scheduled for replacement during periods when the pump is not needed.

In the following analysis, the variables of equation (2) will be expressed as a function of standpipe pressure (SP_i) or pump hydraulic horsepower ($PHHP_i$) so that the ratio of drilling costs can be studied as a function of either variable. Variable fuel costs are directly proportional to engine horsepower required to power the mud pumps and can be expressed by

$$F_i = f\ PHHP_i \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (3)$$

where f is the fuel cost per pump output horsepower-hour. Using a typical specific fuel consumption value for diesel engines of .38 lb/(hp-hr), 80 percent power transmission efficiency and 85 percent pump efficiency, we estimate f to have a value of 8 cents per hp-hour with diesel fuel costs at $1.00 per gallon. Using equation (3), the required fuel cost term of equation (2) can be expressed by

$$\frac{F_2 - F_1}{R_1} = \frac{F_1}{R_1}\left[\frac{PHHP_2}{PHHP_1} - 1\right] \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (4)$$

Using equation (A-7) derived in Appendix A, equation (4) may be written as a function of standpipe pressure by

$$\frac{F_2 - F_1}{R_1} = \frac{F_1}{F_1}\left[C\left[\frac{SP_2}{SP_1}\right]^{v} - 1\right] \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (5)$$

where C and v are constants defined in equation (A-7).

Variable pump maintenance costs may be expressed by the equation

$$PPC_2 = PPC_1\left[\frac{SP_2}{SP_1}\right]^{p} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (6)$$

where p is determined by a fit of available cost data at different standpipe pressures. This equation is suggested by the data of Figure 9 developed by the AAODC Rotary Drilling Sub-Committee on Hydraulics in 1959[13]. A least squared error fit of these data yields p = 1.57. Nelson[14], in his discussion of these data, suggested that the costs may vary with pump horsepower rather than standpipe pressure. We agree with Nelson's observations on intuitive grounds since pump horsepower will account for increased wear due to stroking rates (flow rate (Q)) as well as standpipe pressure increases. A cost model based on pump horsepower can be expressed by

$$PPC_2 = PPC_1 \left[\frac{PHHP_2}{PHHP_1}\right]^p = PPC_1 \left[C \left(\frac{SP_2}{SP_1}\right)^v\right]^p \quad \ldots\ldots\ldots\ldots \quad (7)$$

Using equations (1) and (A-8), the ratio of equation (2) expressed as a function of standpipe pressure is

$$\frac{ROP_1}{ROP_2} = \left[\frac{BHHP_2/N_2}{BHHP_1/N_1}\right]^{-b} = \left[\frac{k_2}{k_1}\frac{N_1}{N_2} C \left(\frac{SP_2}{SP_1}\right)^v\right]^{-b} \quad \ldots\ldots\ldots\ldots \quad (8)$$

where

$$k_i = \frac{BHHP_i}{PHHP_i} = \frac{(BIT\ \Delta P)_i}{SP_i}$$

and N_i is the number of nozzles used in the bit.

Written as a function of the pump horsepower ratio, the ROP ratio can be expressed by

$$\frac{ROP_1}{ROP_2} = \left[\frac{k_2}{k_1}\frac{N_1}{N_2}\frac{PHHP_2}{PHHP_1}\right]^{-b} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (9)$$

A theoretical minimum cost condition for pump operating conditions is derived in Appendix B. For the pump maintenance cost model of equation (6), the following minimizing condition is obtained.

$$\frac{F_1 + PPC_1}{R_1} = b$$

This result indicates that standpipe pressure should be increased until pump fuel and maintenance costs as a fraction of total rig operating costs equal the exponent b which relates ROP response to bit hydraulic horsepower.

For the more conservative pump maintenance cost model of equation (7), a slightly different result is derived in Appendix B.

$$\frac{(p)\ PPC_1 + F_1}{R_1} = b$$

This criteria results in a lower pump horsepower at the minimum cost condition due to the parameter p which is greater than 1.

The theoretical minimum cost conditions may result in standpipe pressure and pump horsepower far beyond normal operating experience. The conditions are invalid if bit and pump horsepower levels beyond the range used to define the empirical exponents b and p are required. A preferable and more practical application of this new optimization approach is to perform a parametric analysis of drilling costs as a function of standpipe pressure or pump hydraulic horsepower to investigate effects of modest changes in pump operating conditions. Such an analysis is easily performed using equations (2)-(9), especially with the aid of a programmable calculator. Applicable constraints on flow rate, standpipe pressure, pump horsepower and bit nozzle sizes should be observed. A practical rule to follow is when the analysis violates a constraint, operate at the constraint. Starting with known operating parameters at condition 1, all values with subscript 1 are known. The constant k_2 should be set equal to 0.65 to provide maximum BHHP according to the Kendall and Goins[1] criteria (see Appendix A). A new standpipe pressure constraint SP_2 is selected and a new flow rate Q_2 can be calculated from equation (A-6). If this flow rate is less than the minimum allowable flow rate (determined from mud and hole conditions) or greater than the maximum allowable flow rate (determined from hole erosion criteria or pump horsepower limitations), Q_2 should be set equal to the applicable constraint and k_2 is then calculated from equation (A-6). This will provide the maximum BHHP possible within the flow rate constraints at standpipe pressure SP_2. With selected values for k_2 and SP_2 and empirical values for b,p and v, equations (2)-(9) can be evaluated.

EXAMPLE PROBLEM

To demonstrate the parametric analyses which can be conducted with equations (2)-(9), results of an example problem are plotted on Figure 10. This example is typical of deep holes with large parasitic pressure losses in the drill string and where very little pressure drop is available for the bit. In this case, the standpipe pressure SP_1 is so restrictive that $k_1 = 0.2$ at the minimum allowable flow rate, far from the desired value of $k_1 = 0.65$ for maximum BHHP. As we consider progressively higher standpipe pressure constraints SP_2, BHHP and the value of k_2 will be allowed to rise. However, because of parasitic pressure losses in the circulating system, flow rate must be held at the minimum allowable value to maximize available bit pressure drop and BHHP until SP_2 is raised sufficiently to allow $k_2 = 0.65$ at the minimum flow rate. For SP_2 values which require operating at the minimum flow rate, $Q_2 = Q_1 = Q_{min}$ and k_2 is calculated from the simplified form of equation (A-6)

$$k_2 = 1 - \frac{1-k_1}{SP_2/SP_1}$$

In this example, initial fuel costs and pump maintenance costs were assumed to be 10 and 5 percent of total rig operating costs, respectively. Empirical values of b = 0.3, p = 1.57 and v = 1.55 were used. The pump maintenance costs model of equation (7) was chosen. However, for this problem, the model of equation (6) gives an identical result because flow rate remains at the constant minimum value. For this example, drilling costs are quite sensitive to the standpipe pressure constraint. A 10 percent increase in standpipe pressure allows a 50 percent increase in BHHP, a 13 percent increase in ROP and a 10 percent reduction in drilling costs. The absolute minimum drilling cost, 30 percent less than the initial value, was found to occur at a standpipe pressure 2.2 times the initial value. For an initial standpipe pressure of 2500 psi, this could prove to be an impractical solution. However, a 20 percent increase in the standpipe pressure constraint to 3000 psi results in a 16 percent reduction in drilling costs, a savings and operating limit worthy of consideration.

FIELD APPLICATION OF MINIMUM COST OPTIMIZATION

The optimization method presented is basically a two step process in which optimum pump operating conditions are first established and then nozzle sizes are selected according to Kendalland Goins[1] criteria to maximize BHHP at the minimum cost operating conditions. In the field, these steps can be reversed without significant loss of the minimum cost effects. Basic to the procedure is establishing a relationship between ROP and BHHP by varying flow rate during a bit run. If desired, the exponent b of equation (1) may be determined although this is not necessary. The steps to follow are:

(1) Determine the exponent u of equation (A-1) according to the field test described by Robinson[15]. If u is not known, use u = 1.82 which is consistent with most hydraulic slide rules and tables. Calculate the maximum jet impact force condition ($k_j = u/(u+2)$ 0.48) and the maximum BHHP condition ($k_H = u/(u+1)$ 0.65)

(2) Carefully measure and select nozzle sizes and flow rate to provide maximum BHHP ($k_1 = k_H$ at the normally observed standpipe pressure limit. If this requires a flow rate less than the minimum allowable, operate at the minimum flow rate and select nozzle sizes to use all available bit pressure drop at the minimum flow rate constraint. This will result in lower parasitic pressure losses in the circulating system and provide the maximum BHHP possible within the operating constraints.

(3) After breaking in the bit, and desired weight and RPM are established, record ROP_1, Q_1 and SP_1 and calculate $BHHP_1$ using measured nozzle diameters.

(4) Reduce flow rate to the minimum allowable value consistent with adequate cuttings removal and allow drilling rate to stabilize at the new value. Record ROP, Q, SP and calculate BHHP.

(5) Increase flow rate until a safe physical limit on standpipe pressure or maximum allowable flow rate is reached, allow drilling rate to stabilize and record data and calculate BHHP as above.

(6) If desired, other data points can be taken at intermediate flow rates and combined with the other data to form a table of values (SP_i, ROP_i, Q_i, $BHHP_i$).

(7) Return to the initial flow rate and standpipe pressure condition until the optimum flow rate condition is determined.

The SP_i and Q_i values obtained in steps 3-6 can be used to calculate $PHHP_i$. Using known values for R_1, F_1, PPC_1, p, and $v = (u+1)/u$, equations (4) and (6) or (7) may be used to calculate fuel and pump maintenance cost variations from the initial operating condition. These values along with measured values for ROP_i may be used directly in equation (2) to calculate the drilling cost ratio DC_i/DC_1. These cost values can be plotted against SP_i and a minimum cost operating condition can be selected graphically. Flow rate should then be adjusted to obtain the standpipe pressure associated with the minimum drilling cost condition. As flow rate is increased with fixed nozzle sizes in the bit, the value of k_i will rise slightly from the initial value. However, there will be less than a 4 percent change in k_i with 50 percent increases in flow rate when $0.5 < k_1 < 0.65$. Thus, k_i will remain between the maximum jet impact and maximum BHHP condition, a good practical optimum.

Fur future bit runs or drilling offsets at the same depth, the exponent b can be determined from the data collected by one of the two methods described below.

Method 1 - Use a linear regression program[18] for a programmable calculator on the following logarithmic form of equation (1)

$$\log ROP_i = g \log (BHHP_i/\text{nozzle}) + \log K$$

An example of which is derived from the data of Figure 2 and replotted in Figure 11.

Method 2 - Plot ROP_i vs $BHHP_i$ or $BHHP_i$/nozzle on log-log paper and measure b from the slope of the best straight line fit of the data points.

With b determined, a parametric analysis similar to the example of Figure 10 can be conducted to establish optimum pump operating conditions and BHHP without the restriction of the particular nozzle sizes used to obtain the data. Nozzles can then be selected for future bit runs based on the anticipated optimum pump operating conditions and constraints on flow rates and nozzle sizes.

As experience is gained operating at higher standpipe pressures and pump horsepower, pump maintenance cost data should be retained to establish a value of p more pertinent to the particular rig and drilling conditions. Higher standpipe pressures and BHHP may call for nozzles smaller than desired to avoid nozzle plugging with lost circulation materials. In this case, the use of two nozzles rather than three will usually solve the problem and in most cases should provide even better ROP performance. Two nozzles are not as effective when cutter balling is a problem. In such cases, an asymmetric three nozzle configuration will provide better cutter cleaning and should improve ROP.

CONCLUSIONS

The model of equation (1) has been correlated with a wide range of full scale laboratory drilling data demonstrating its applicability in hydraulics optimization for minimum cost per foot drilling. The model also predicts ROP improvements which can be expected with asymmetrical two and three nozzle configurations.

Hydraulic requirements for bits should be based on considerations of minimum drilling cost per foot. A method for optimizing bit hydraulics according to minimum drilling cost criteria has been developed. Based on theory presented here, minimum drilling costs are achieved when pump fuel and maintenance costs are a certain fraction of total rig operating costs, the fraction being equal to the exponent b of equation (1).

Percentage changes in ROP rather than absolute changes are important in minimum drilling cost per foot optimization. Increases in pump hydraulic horsepower and BHHP/nozzle in slow ROP deep drilling can be very effective in reducing cost per foot. Modest increases in standpipe pressure can result in large percentage increases in BHHP/nozzle and significant percentage improvement in ROP.

NOMENCLATURE

b = exponent on BHHP/nozzle relating ROP to BHHP/nozzle

$BHHP_i$ = bit hydraulic horsepower at hydraulic condition i - HHP

$(\text{Bit } \Delta P)_i$ = pressure drop across bit at hydraulic condition i - psi

C = constant calculated from k_1, k_2 and u

DC_i = drilling cost per foot at hydraulic condition i - \$/ft

f = fuel cost to power mud pumps per horsepower per hour - \$/(HP-hour)

F_i = fuel cost to power pumps at hydraulic condition i - \$/hour

i = subscript used to denote hydraulic condition

K = constant relating ROP to BHHP/nozzle

K_c = constant for a particular drill string length and configuration relating parasitic pressure losses to flow rate.

$K'_c = K_c/1714$

k_i = ratio of $BHHP_i$ to $PHHP_i$ at condition i

k_H = value of k_i which maximizes $BHHP_i$ at constant standpipe pressure or PHHP

k_J = value of k_i which maximizes jet impact force at constant standpipe pressure

p = exponent on SP or PHHP ratios used to calculate relative pump maintenance costs

$PHHP_i$ = pump hydraulic horsepower at condition i - HHP

PPC_i = expendable pump parts maintenance cost per hour at condition i - \$/hour

Q_i = flow rate at hydraulic condition i - gal/min

R_i = rig hourly operating costs including fuel and pump maintenance at hydraulic condition i - \$/hour

ROP_i = rate of penetration at condition i - ft/hour

SP_i = standpipe pressure at condition i - psi

u = exponent on flow relating circulating system pressure losses to flow rate

$v = (u+1)/u$

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17. Black, A.D., Tibbitts, G.A., Sandstrom, J.L., and DiBona, B.G., "Effects of Size on Three-Cone Bit Performance in Laboratory Drilled Shale", SPE-11231, 57th Annual Fall Technical Conference and Exhibition, New Orleans, La., Sept. 26-29, 1982.

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APPENDIX A

Pressure losses in a rig circulating system may be described by

$$SP = \text{Bit } \Delta P + \left[K_c Q^u\right] \quad \text{(A-1)}$$

where SP is standpipe pressure, K_c is a constant for a given drill string length and configuration, Q is flow rate and u has a value between 1 and 2 depending on the relative amount of laminar and turbulent flow in the system. In most popular hydraulic slide rules and tables, u is assigned a value of about 1.82. Robinson[15] describes a field test procedure which can be used to determine a more accurate value of u for a specific drilling situation.

Multiplying equation (A-1) by Q and appropriate constants to convert to horsepower yields

$$PHHP = BHHP + K'_c\, Q^{u+1} \quad \text{(A-2)}$$

It is convenient to define the variables

$$k_i = \frac{BHHP_i}{PHHP_i} = \frac{(\text{Bit } \Delta P)_i}{SP_i} \quad \text{(A-3)}$$

for hydraulic operating condition i. Derivations similar to those presented by Kendall and Goins[1] specify values of k_i in terms of u at several well known conditions:

$k_i = \frac{u+1}{u+2} = 0.74$	maximum jet impact force at maximum pump horsepower
$k_i = \frac{u}{u+2} = 0.48$	maximum jet impact force at maximum standpipe pressure
$k_i = \frac{u}{u+1} = 0.65$	maximum BHHP at maximum standpipe pressure limit or maximum pump horsepower and minimum allowable flow rate

Substituting (A-3) into (A-2) and forming a ratio of (A-3) for two different hydraulic conditions provides the following relationship

$$\left[\frac{Q_2}{Q_1}\right]^{u+1} = \frac{PHHP_2}{PHHP_1}\;\frac{(1-k_2)}{(1-k_1)} \quad \text{(A-4)}$$

since K'_c does not change with Q.

By definition,

$$\frac{PHHP_2}{PHHP_1} = \frac{SP_2Q_2}{SP_1Q_1} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (A\text{-}5)$$

Substituting (A-5) into (A-4) yields

$$\frac{Q_2}{Q_1} = \left[\frac{SP_2}{SP_1} \; \frac{(1-k_2)}{(1-k_1)}\right]^{\frac{1}{u}} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (A\text{-}6)$$

Using (A-5) and (A-6) we can also write

$$\frac{PHHP_2}{PHHP_1} = \left[\frac{(1-k_2)}{(1-k_1)}\right]^{\frac{1}{u}} \left[\frac{SP_2}{SP_1}\right]^{\frac{u+1}{u}} = C \left[\frac{SP_2}{SP_1}\right]^{v} \quad \ldots\ldots\ldots\ldots \quad (A\text{-}7)$$

where $v = (u+1)/u = 1.55$

From equation (A-3) and (A-7) it is also clear that

$$\frac{BHHP_2}{BHHP_1} = \frac{k_2}{k_1}\,\frac{PHHP_2}{PHHP_1} = C \;\frac{k_2}{k_1}\left[\frac{SP_2}{SP_1}\right]^{v} \quad \ldots\ldots\ldots\ldots \quad (A\text{-}8)$$

APPENDIX B

Substitution of equations (5), (6) and (8) into equation (2) expresses the drilling cost ratio as a function of the standpipe pressure ratio,

$$\frac{DC_2}{DC_1} = \left\{1+\frac{F_1}{R_1}\left[C\left[\frac{SP_2}{SP_1}\right]^{v}-1\right] + \frac{PPC_1}{R_1}\left[\left[\frac{SP_2}{SP_1}\right]^{p}-1\right]\right\}\left[\frac{k_2N_1}{k_1N_2}\,C\left[\frac{SP_2}{SP_1}\right]^{v}\right]^{-b} \quad \ldots\ldots \quad \text{(B-1)}$$

For unconstrained variations in standpipe pressure, a minimum of equation (B-1) can be found by taking a derivative of (B-1) with respect to the ratio SP_2/SP_1 and setting the result equal to zero. After considerable manipulation this leads to the minimizing condition

$$\frac{PPC_1}{R_1}\left[\left(\frac{p}{v} - b\right)\ \frac{SP_2}{SP_1}^{p} + b\right] + \frac{F_1}{R_1}\left[C\ (1-b)\left[\frac{SP_2}{SP_1}\right]^{v} + b\right] - b = 0 \quad \text{(B-2)}$$

Let SP_1 be the standpipe pressure which provides minimum drilling costs. Then at the minimum cost condition, the ratio $SP_2/SP_1 = 1$. Using the approximation

$$p = 1.57 \qquad v = 1.55$$

and letting $k_2 = k_1$ which yields $C = 1$ reduces equation (B-2) to

$$\frac{PPC_1 + F_1}{R_1} = b \quad \ldots\ldots\ldots\ldots\ldots \quad \text{(B-3)}$$

Thus, at the minimum drilling cost condition we find that the fraction of total rig operating costs associated with pump maintenance and fuel should equal the exponent b of the ROP response equation (equation (1)).

A slightly modified form of equation (B-3) is obtained when the pump maintenance cost model of equation (7) is used. In this case, more pump maintenance costs are incurred at a given operating standpipe pressure since pump speed increases (increased flow rate) are not free. Substituting equations (4), (7) and (9) into equation (2) yields drilling costs as a function of the pump horsepower ratio $PHHP_2/PHHP_1$,

$$\frac{DC_2}{DC_1} = \left\{1 + \frac{F_1}{R_1}\left[\frac{PHHP_2}{PHHP_1} - 1\right] + \frac{PPC_1}{R_1}\left[\left[\frac{PHHP_2}{PHHP_1}\right]^{p} - 1\right]\right\}\left[\frac{k_2N_1}{k_1N_2}\ \frac{PHHP_2}{PHHP_1}\right]^{-b} \quad \ldots \quad \text{(B-4)}$$

For unconstrained variations in pump hydraulic horsepower, a minimum of equation (B-4) can be found by setting the derivative of (B-4) with respect to the PHHP ratio equal to zero. This leads to the minimizing condition,

$$\frac{PPC_1}{R_1}\left[(p-b)\ \frac{PHHP_2}{PHHP_1}^{p} + b\right] + \frac{F_1}{R_1}\left[(1-b)\ \frac{PHHP_2}{PHHP_1} + b\right] - b = 0 \quad \ldots\ldots \quad \text{(B-5)}$$

Letting $PHHP_1$ be the minimizing PHHP, forces $PHHP_2/PHHP_1 = 1$ at the minimum and yields the condition,

$$\frac{(p)\ PPC_1 + F_1}{R_1} = b \quad \ldots\ldots\ldots\ldots\ldots \quad \text{(B-6)}$$

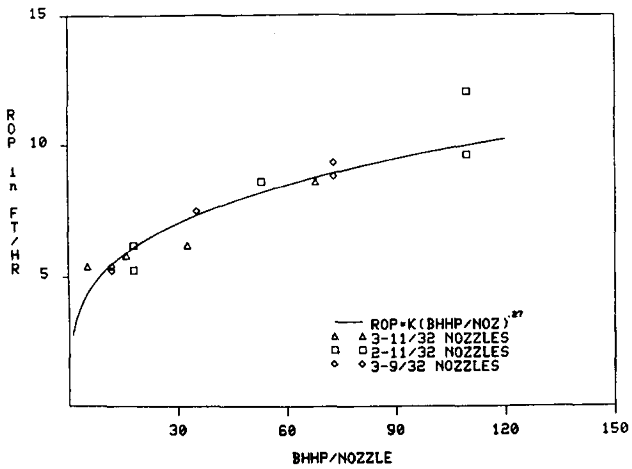


Figure 1 - ROP vs. BHHP/nozzle in Mancos Shale at 4000 psi overbalance pressure

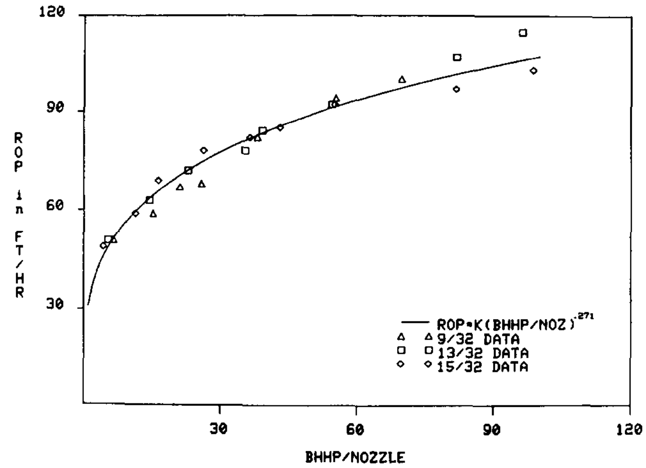


Figure 2 - ROP vs. BHHP/nozzle in Indiana Limestone at 100 psi overbalance pressure

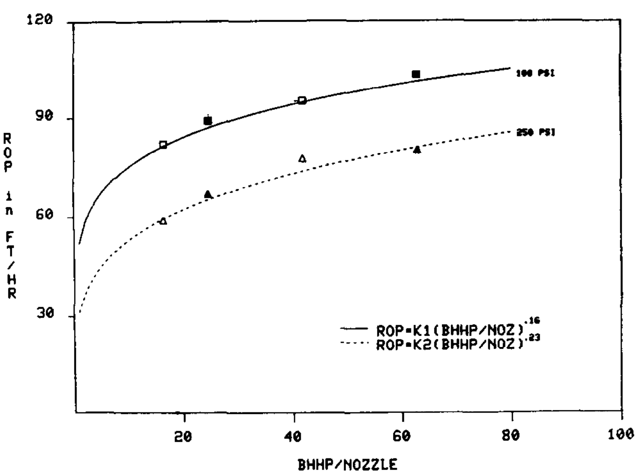


Figure 3 - ROP vs. BHHP/nozzle in Indiana Limestone

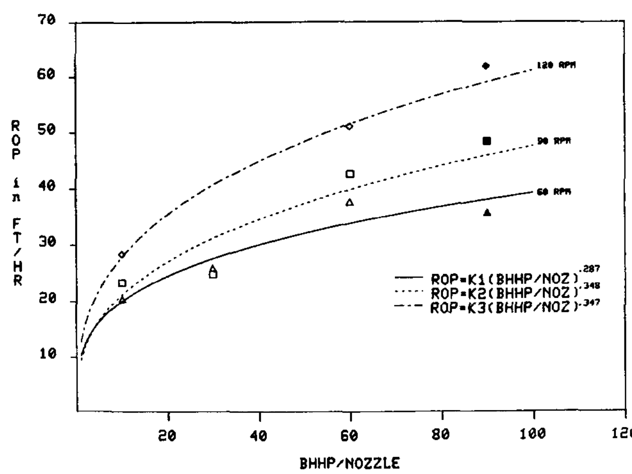
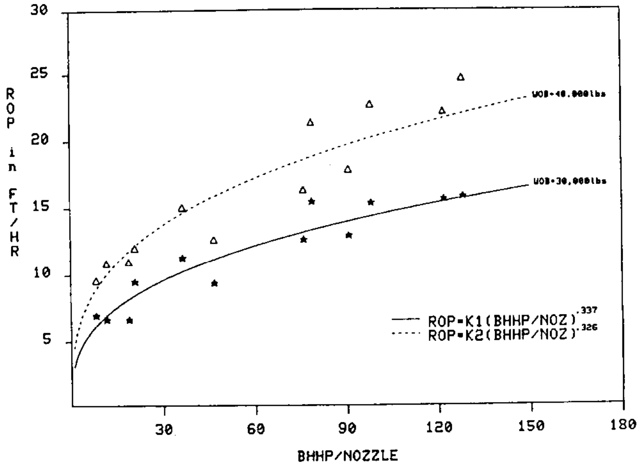


Figure 4 - ROP vs. BHHP/nozzle in Mancos Shale at 700 psi overbalance pressure



*FROM SPE-8439

Figure 5 - ROP vs. BHHP/nozzle in Mancos Shale at 2000 psi overbalance pressure

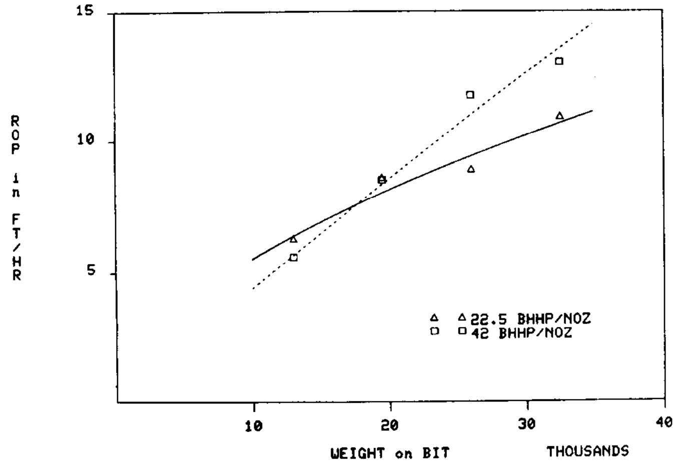


Figure 6 - ROP vs. WOB; effect of increasing BHHP/nozzle

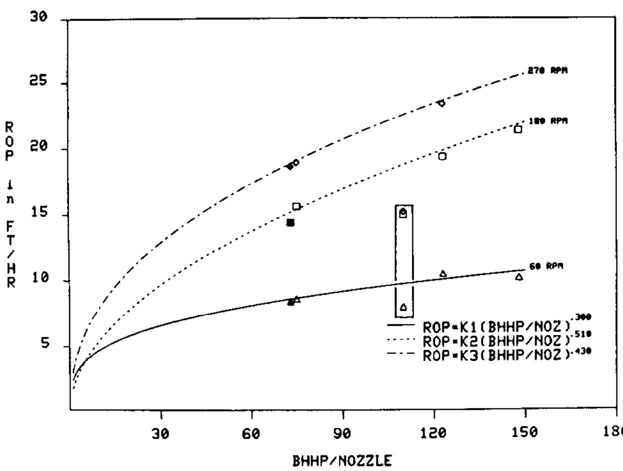


Figure 7 - ROP vs. BHHP/nozzle and RPM in Mancos Shale at 4000 psi overbalance

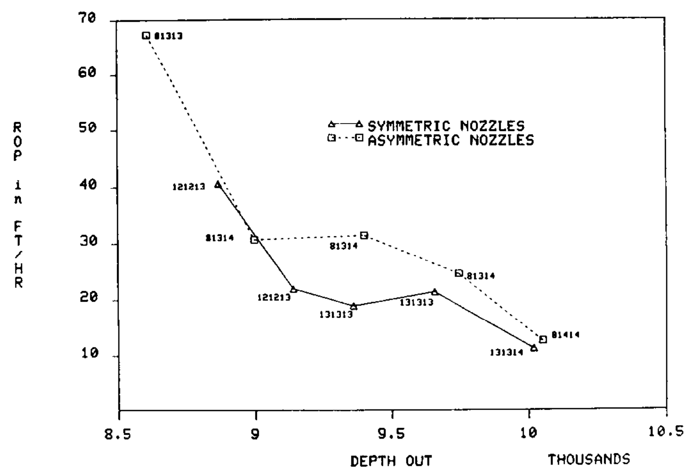


Figure 8 - Field comparison of symmetric and asymmetric nozzles; Matagorda County, Texas

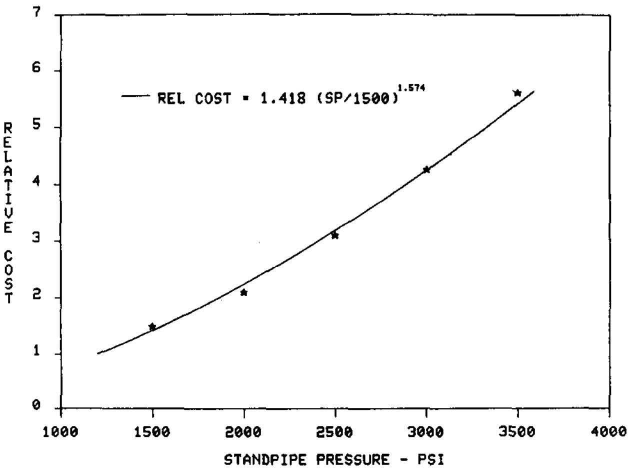


Figure 9 - Relative pump maintenance cost vs. standpipe pressure

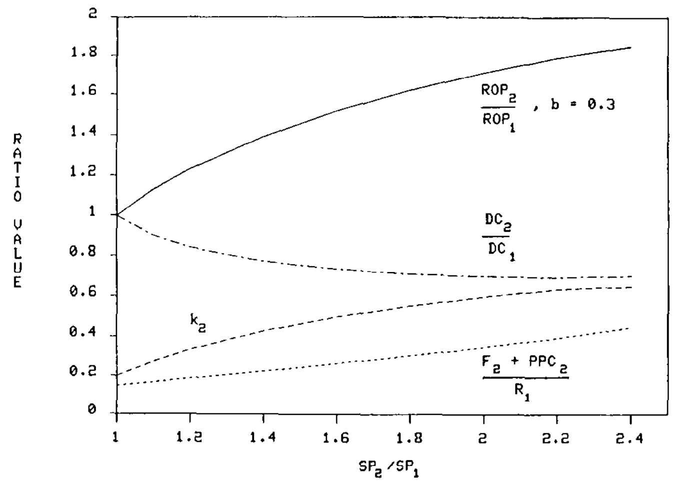


Figure 10 - ROP and cost trends with increasing standpipe pressure; $k_1 = 0.2$

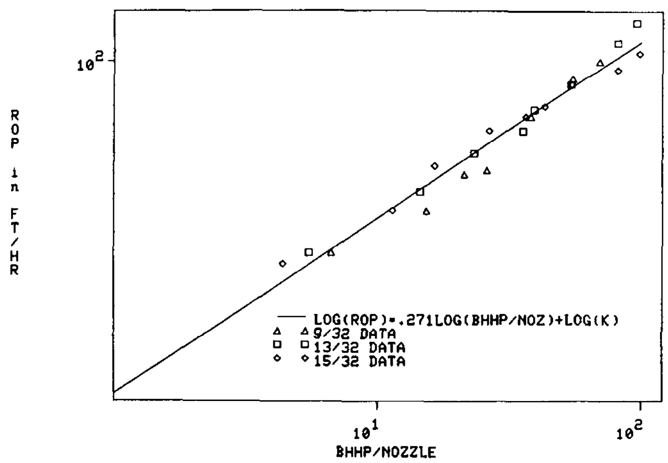


Figure 11 - ROP vs. BHHP/nozzle from Figure 2