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Basic Drilling Problems And Optimization By General Intensive Knowledge

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ABSTRACT

Oil well drilling is a highly complex process that leads to routine drilling operational problems. A drilling problem is any occurrence or condition that stands in the way of good objectives. It could involve anything from weather to transportation delays to blowouts. This paper concentrate on problems that occur as part of the drilling process itself and a possible way to reduce such problems. A comprehensive, thoroughly researched well plan is our best defense against drilling problems. In order to minimise some of these problems, an extensive study was carried out on different drilling problems cases. An important problem in drilling is hole cleaning, in which a high number of observed parameters and other features are involved. This paper aimed to determine the basic problem associated with the drilling process of poor hole cleaning and create a simplified way based on drilling literature to optimize the drilling process according to the total drilling costs for a set of given conditions and moreover, to identify the optimally controlled variables for the drilling process. Drilling optimization involves using available resources to minimize overall cost, subject to safety and well completion requirements. Part of this, of course, entails preventing or successfully solving hole problems. Conclusively, after an extensive literature search was performed, covering the drilling process and the challenges involved. The optimization of the drilling process was analyzed separately for the active drilling operations and pipe connections and drilling trips. The result shows that many parameters are involved in the drilling process, and deviation of one factor may lead to hole cleaning issues and other problematic situations, the time spent during pipe connection- and drilling trip procedures is identified as an important factor in the optimization of the drilling process. The constraints on the bottom hole pressure and mud circulation rate were active at the optimum but removed from further analysis when the bottom hole pressure was controlled by the choke pressure, while the main mud pump flow rate was kept constant. For single measurement controlled variables, the results show that it is optimal to control the top drive power by manipulating the drill string rotational speed and keep the weight on bit (WOB) constant. The combination of several measurements will give a minimum loss, with an increase in the complexity of the control structure.

***Keywords:* Drilling Problem, Optimisation, Hole Cleaning Problems, Factors Affecting Penetration Rate, Drilling Parameters Optimisation.**

1.0 INTRODUCTION

The goals of any drilling venture are *safety*, *minimized cost* and a *usable completion*. Companies may have different ideas of how best to attain these goals, and drilling practices may vary according to location, rig type, hole conditions or other factors. But the goals remain always the same. *Safety* is the primary concern in drilling an oil or gas well. Protection of personnel supersedes all other well objectives, even when it means altering the good plan, incurring unexpected costs or delaying operations. Failure to make safety the top priority on a rig can result in accidents, disabling injuries, loss of and deaths. The second priority in drilling is to protect the well and the surrounding environment, anticipate potential problems and include provisions in the well plan to minimize blowout risks or other dangers, and continually monitor operations once the rig moves on location. A *usable completion* should be the outcome of any drilling operation, whether the well is a producer, an injector or simply a source of information. Even a safely drilled, low-cost well is not entirely successful if it does not meet the needs that led to it being drilled in the first place. As a minimum standard, a well should have no irreparable damage to the hole or producing formation and a sufficiently large hole diameter for running completion equipment or carrying out other post-drilling activities. The process of drilling a well is very expensive, costing a huge amount of dollars per day. So any time loss caused by drilling process will not be compromised as it involves hiring a drilling rig and crew for the duration of drilling the well. It is, therefore, important to drill the well as fast as possible in order to minimize the cost. The drillers are highly experienced personnel that are tasked to drill fast and safe while keeping within a set of boundaries and handling upsets. However, the drilling process involves coordinating a lot of machinery and making quick decisions with the possibility of severe consequences. During drilling, all the drill cuttings need to be removed, i.e. transported to the surface, a process which is referred to as hole cleaning. Often some of the material remains in the well which to problems such as; Pipe sticking, Premature bit wear, Slow drilling, Formation damage – fracturing, Excessive torque and drag, Trouble in logging and cementing. Hole cleaning is still among the most important problems to deal with during drilling. It is also one of the most studied phenomena within the petroleum industry. Ineffective hole cleaning can in extreme cases lead to loss of the well or a part of it, i.e. stop of the drilling process and blocking of the hole. The catastrophic blowout on the drill rig Deepwater Horizon in the Gulf of Mexico in April 2010 clearly showed the magnitude of the potential dangers. The blowout led to the burning and sinking of the drill rig (see Figure 1.1), and an oil leak with huge environmental impact. Naturally, the situation became the focus of world press and political agendas, as well as having enormous economic consequences for the responsible companies.

An extensive literature search is an approach to problem-solving and decision-making based on similar previously solved problems, called cases, and optimizing them in the new problem situation. Application-oriented research in the area of case-based study has moved mature research results into practical applications. Skalle et al [11] employed case based reasoning to improve the efficiency of oil well drilling. Their focus was on lost circulation, which means that some of the drilling fluid that always fills the gap between the drill string and the good wall gets lost into fractures in the geological.

Many of the decisions made on the rig floor require extremely good knowledge of the various effects in the drilling process, and they should be made faster than what is possible for a human. Also, the decisions are often based on experience and out-dated industry standards which are not necessarily optimal for each and every purpose. Therefore, the drilling process has great potential for increased automation and optimization in terms of process control.

1.1 The hole cleaning problem

A drilling process consists of several steps, of which the actual drilling into the geological formation and the continuous cleaning of the borehole are core subprocesses. One of the purposes of the drilling mud is to transport the drill cuttings away from the bit and up to the surface through the good annulus. It is very important to ensure effective transport of the cuttings, otherwise, the drill bit will keep grinding the cuttings that accumulate at the bottom of the well with the very slow footage. This will lead to a lower rate of penetration and thus less efficient drilling. The hole cleaning issues arise when the drilling direction moves from vertical to deviated and horizontal hole angles. Horizontal drilling is getting more and more common, due to the increasing distance from the rig to productive wells. (“All the easy wells are already drilled”, as the phrase goes). Accumulation of solids at a certain depth is a common source of pack off, which is a serious situation indicated by the building up of material inside the hole wall, with reduced hole diameter as a result.

Many studies have been carried out by other researchers related to the cleaning of vertical, deviated and horizontal holes [1], [2], [3], [4], [8], [9]. However, the results of the studies have so far not provided clear operational recommendations. One reason may be that such studies focused just on the role and effect of individual parameters. An intensive study approach, on the other hand, views a larger set of parameters as a unit, without assuming particular restrictions on the parameters, such as independent parameter. This approach is targeted at reducing the risk of unwanted downtime (i.e. stopped drilling) to minimize the drilling cost. The drill plan acts as guidance to expected drilling behavior. The real-time data from the drilling process is the main source of a situation description, which is matched with a past case in order to identify possible hole cleaning problems ahead of the drill bit.

The circulation rate and properties of the drilling mud determine its capacity of transporting the cuttings. First, the slip velocity of the particles must be determined, which is dependent on the geometry and density of the cuttings. The slip velocity for Newtonian fluids in creeping flow, i.e. very low Reynolds numbers (< 0.1), may be calculated using Stoke’s law. Choosing realistic values for the annulus velocity, mud density, viscosity and the diameters of the drill string and well, an estimate of the Reynolds number may be made as shown Equation **2**. The hydraulic diameter of an annulus may be calculated using Equation **1**

$$d_H = \frac{\pi(d_b^2 - d_s^2)}{\pi(d_b + d_s)} = d_b - d_s \qquad 1$$

$$N_{Re} = \frac{\rho f v_a d_H}{\mu} = \frac{1400kg\ .0.7\ m/s}{0.02pa}\ (0.254m - 0.100m) = 7546 \qquad 2$$

From Equation **2,** it is clear that Stoke's law can not be used. For Reynolds numbers over 0.1, empirically determined friction coefficients must be used. The friction coefficient, in this case, is defined in Equation **3**.

$$f = \frac{F}{AE_k} \qquad 3$$

where
• F = force exerted on the particle due to viscous drag,
• A = characteristic area of the particle, and
• E_K = kinetic energy per unit volume.[10]

The force F is the difference between the weight and buoyancy of the particle, Given by Equation **4**. The particle diameter is denoted dp, whiles and f denote the particle density and the effective mud density, respectively. The kinetic energy E_K is defined by Equation below, where v_{sl} is the particle slip velocity.

$$F = F_g - F_{bo} = (\rho_s - \rho_f)g\ \frac{\pi d_p^3}{6} \qquad 4$$

$$E_K = \frac{1}{2}\rho_s v^2{}_{sl} \qquad 5$$

Assuming the particles are spherical, the characteristic area is given as $A = \pi\ d^2{}_p/4$. Combining the equations gives Equation below for the friction factor.

$$f = \frac{4}{3}\ g.\ \frac{\rho s - \rho f}{\rho f}\ \frac{d_p}{v_{sl}^2} \qquad 6$$

Several correlations have been proposed in order to let the slip velocity equations apply for non-Newtonian fluids, such as drilling muds. Moore [5, 10] proposed that for Reynolds numbers above 300, the flow around the particle is fully turbulent and the friction factor becomes constant at a value of about 1.5. Chien [6, 10] recommends the use of 1.72 for the friction coefficient for Reynolds numbers above 100. Though slightly different for lower Reynolds numbers, the different correlations seem to agree rather closely for turbulent flows. Thus, using Moore's correlation and solving Equation **6** for the slip velocity, we get Equation below.

$$v_{ls} = \sqrt{\frac{8}{9}\frac{\rho s - \rho f}{\rho f}\ g.dp} \qquad 7$$

1.2 Drilling model equations

The effective transport velocity v_T of the cuttings is defined as the difference between the annulus mud velocity and the slip velocity of the particles. The expression is shown in Equation below.

$$v_T = v_a - v_{slip} \qquad 8$$

Assuming that the mud flow through the bit (qbit) is equal to the mud flow from the main pump (qin), the annulus flow velocity is expressed as follows. Aa represents the cross-sectional area of the well annulus.

$$v_a = \frac{qbit}{Aa} = \frac{q_{in}}{\pi(d_b^2 - d_s^2)} \qquad 9$$

The transport velocity can also be used in calculating the fraction of cuttings (xc) in the mud that is flowing in the well annulus, since it can be expressed as a function of the rate of cuttings as shown by the equation below. [10]

$$v_T = \frac{q_s}{A_a X_c} \qquad 10$$

The feed of cuttings per second (qs) is determined by the ROP (R) as shown in Equation:

$$q_s = \frac{R}{3600} A_b = \frac{R}{3600} \pi \frac{d_b^2}{4} \qquad 11$$

And the fraction of solids in the mud return can be calculated by re-organizing Equation **10** as shown in the folowing Equation.

$$X_c = \frac{q_c}{A_a v_T} \qquad 12$$

The effective density of the returning mud is dependent on the fraction of cuttings and is calculated using the given Equation below.

$$\rho_f = x_c \rho_s + (1 - x_c) \rho_m \qquad 13$$

The transport velocity v_T must be greater than zero in order for the cuttings to be transported out of the well. A negative v_T means that the slip velocity is higher than the annulus velocity, resulting in an accumulation of cuttings at the bottom of the well. While a small, positive $\mathbf{v_T}$, in theory, would bring the cuttings to the surface, this would result in a very high percentage of cuttings in the mud and significantly increase the mud density, which in turn would lead to a higher bottom-hole pressure and thus less favorable drilling conditions.

1.3 Bottom Hole Pressure

All measurements obtained from the bottom of the well are in practice rather difficult to obtain effectively. Normally the measurements are sent to the top by mud pulse telemetry, but this technology is ineffective during times of lost circulation and when the mud circulation rate is low. Mud-pulse telemetry requires a minimum flow rate of approximately 600-1000 liter/min. Underbalanced drilling also imposes challenges to mud pulse telemetry, as a gas that is introduced to decrease the equivalent mud density causes signal attenuation and drastically reduces the ability to transmit data through the mud.

The measurement of the bottom hole pressure was modeled using simple fluid mechanics. The flow of mud through the good annulus to the surface may be used to determine the pressure profile. The annulus flow is assumed to be one-dimensional and we neglect other momentum effects that may be experienced due to the rotation of the drill string. We also assume that the drilling fluid is incompressible.

At steady-state and applying the assumptions above, the Navier-Stokes equations are reduced to the equation below. **F** represents the friction forces affecting the flow, **z** is the length coordinate along the path of the flow (positive direction upwards), while $\mathbf{A_a}$ represents the cross-sectional area of the annulus.

$$0 = -\frac{\partial p}{\partial z} - \frac{1}{Aa}\frac{\partial F}{\partial z} - \rho f g \qquad 14$$

After integration with the assumption of the friction gradient to be constant and the Z limit to be from z = -D to z = 0.

We assume the friction gradient ∂F / ∂z is constant, and integrate Equation **14** from z = −D to z = 0. D is the depth of the well in meters (D > 0).

$$P_{bh} = P_c + \frac{1}{Aa}\frac{\partial F}{\partial z} D + \rho f g D \qquad 15$$

The friction loss term is dependent on the geometry of the flow (the annulus) and is difficult to calculate accurately. For this simple model, we assume that the annulus pressure drop due to friction is linearly dependent on the mud flow. For a mudflow of $1 m^3$/min, we assume a 15 bar pressure drop. The final equation for the bottom-hole pressure measurement is given below:

$$p_{bh} = p_c + \theta q_{in} + \rho f g D \qquad 16$$

The term p_c represents the choke pressure, which is the pressure at the top of the annulus. The choke pressure term is only relevant for MPD systems that involve a sealed-off annulus (RCD) and choke valve. For conventional drilling with an open mud return, pc is equal to the atmospheric pressure. The term θq_{in} represents the pressure loss due to friction while the last term $\rho f g D$ is the hydrostatic pressure from the annulus mud column.

2.0 Factors Affecting Penetration Rate

There are many variables that affect how fast and for how long we can drill a given interval. Such as; formation properties, mud properties, hydraulics, bit type, weight on bit, rotary speed and bit tooth wear. The relationships between each of these variables parameters and drilling performance may result in many unknowns, making it difficult to develop a comprehensive and effective drilling model.

The most important formation properties with respect to drilling performance include compressive strength and elastic limit, porosity and permeability.

A highly porous, permeable formation with low compressive strength generally exhibits higher penetration rates than a high-strength, "tight" formation.

Formation depth plays a significant role in determining penetration rates. Compaction normally increases with increasing depth, resulting in lower porosity, higher compressive strength and, consequently, lower penetration rates. Mineralogical characteristics such as abrasiveness and hydration are also important in determining drilling performance.

Mud properties also affect penetration rate. In a normal-pressure field, the differential pressure between the wellbore and the formation increases with increasing mud weight, inhibiting effective cuttings removal and causing penetration rates to decrease (*Figure* 1, Effect of differential pressure on penetration rate). Penetration rates also tend to decrease with increasing viscosity and solids content, while they usually increase with higher filtration rates.

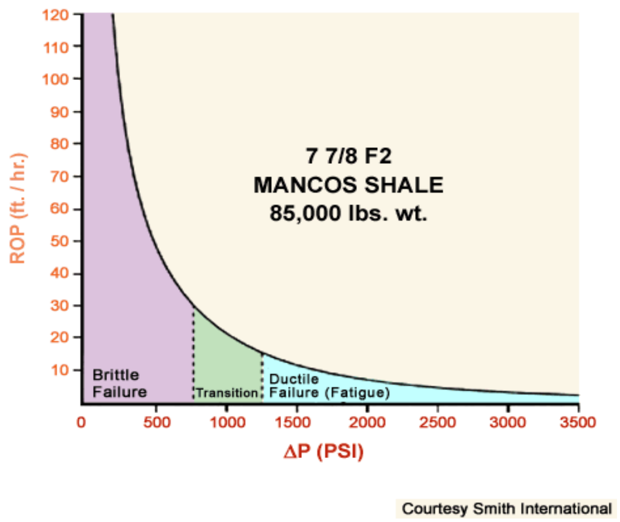

Figure -1 Effect of differential pressure on penetration rate

3.0 Drilling parameters optimization

Drilling optimization involves using available resources to minimize overall cost, subject to safety and well completion requirements. Part of this entails preventing or successfully solving hole problems. But optimization efforts also encompass "normal" operations. The key measure performance in this area is the cost to drill a given well interval. To optimize drilling operations, we must do three things:

- Establish criteria for evaluating drilling performance.
- Identify the variables that affect this performance.
- Determine how to control these variables to our advantage.

Evaluating drilling performance means; proper selection of the drill bit with good performance under various sets of operating conditions. It is achieved using the equation below.

C = (Bit costs) + (Trip costs) + (Rotating, or "on bottom" costs) *17*

We can use the above equation also for both analyzing historical drilling data (i.e., from offset wells), and for monitoring the current bit run. We can best evaluate cost per foot on the basis of *single bit runs*. This provides us with a means of comparing individual bits, and also allows us to make the following assumptions:

- Since the bit is already in the hole, C_{bit} is constant.

- Hourly rig cost is unlikely to vary significantly during a bit run; we can, therefore, consider C_{rig} a constant.
- Trip time (t) does not change during the bit run, we can thus define bit cost, rig cost and trip time as fixed cost parameters.

- Bit cost (C_{bit}), depending on a bit's size, type, and condition (i.e., new or used), may range from several hundred to tens of thousands of dollars. We can group bit types into two basic categories:
- Rolling cutter, which includes milled steel tooth and tungsten carbide insert bits
- Fixed cutter, which includes steel cutter, natural diamond and polycrystalline diamond compact (PDC) bits
- Within these basic categories are an ever-growing variety of sub-classifications and a wide array of design features. Selection of a particular bit type is based on offset well records (when available) or earlier bit runs on the current well. Major considerations in bit selection include the following:
- Formation hardness and abrasiveness
- Mud type (oil-based, water-based, air or foam)
- Differential pressure (amount of overbalance)
- Directional or horizontal drilling requirements
- Type of rotating system (rotary table or downhole mud motor)
- Coring requirements
- Hole size

The effect of bit selection on overall cost per foot depends not only on the bit's cost but also on its performance. An inexpensive bit (or, conversely an expensive, high-performance bit) may or may not result in a minimum cost per foot.
The bit performance is affected by some variables that include; Rotating hours (T) and drilled depth (ΔD) which depend on a wide range of factors that may change during a bit run.
The overall cost per foot of bit run is equal to the sum of its fixed and variable costs. In terms of cost per foot, considering the equations below:

$$\frac{C}{\Delta D} = \left[\frac{C_{fixed}}{\Delta D}\right] + \left[\frac{C_{variable}}{\Delta D}\right] \qquad \textbf{\textit{18}}$$

$$\left[\frac{C_{fixed}}{\Delta D}\right] = \frac{C_{bit} + (C_{rig} \times t)}{\Delta D} \qquad \textbf{\textit{19}}$$

$$\left[\frac{C_{variable}}{\Delta D}\right] = \frac{C_{rig} \times T}{\Delta D} \qquad \textbf{\textit{20}}$$

Equation **19** shows that where the bit cost, rig cost and trip time are constant, drilled depth is the governing parameter in determining fixed costs, while Equation **20,** shows an inverse relationship between variable cost and rate of penetration.
The fixed and variable costs relative contributions to the overall drilling cost can be altered significantly during a bit run. As the bit first starts to drill, most of the operating expense is attributable to bit cost and trip time. when the bit continues to drill, the fixed cost start to decrease while the variable costs increase until they eventually exceed the fixed costs. The net effect of these fixed and variable parameters changing contributions is that overall cost per foot decreases from a high initial value to a minimum, and then begins to increase as the bit dulls.

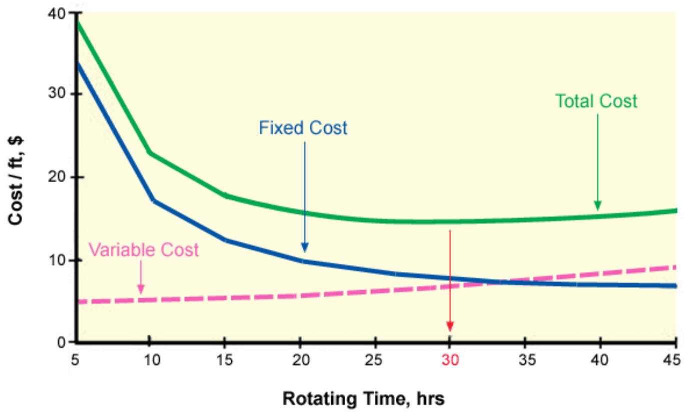

Figure 2: The net effect of fixed and variable parameters to the overall drilling cost

Minimum cost per foot of $14.33 occurs at T = 30 hours.

It is interesting to note that the initial high cost per foot is due mainly to bit cost, and begins to drop off rapidly as the bit accumulates time on the bottom. However, cost per foot does eventually reach a minimum beyond this point, it is not economical to continue the bit run. Minimum cost per foot of $14.33 occurs at T = 30 hours.

Here, the bit cost, rig cost and trip time are taken to be constant for a single bit run, but the primary concerns are rotating hours (i.e, bit life), drilled footage and instantaneous penetration rate (ΔD/dT).

3.10 Drilling performance

Formation properties are critical in determining drilling performance. Mud properties and bit types, though they can be controlled, do not change significantly during a normal bit run. However, hydraulics, bit weight, and rotary speed can be control effectively.

Drilling performance depends largely on how well we remove drill cuttings from the bottom of the hole. If hole cleaning is inadequate, the bit flounders which decreases the penetration rate. Fortunately, we can exercise a great deal of controlling a hole cleaning simply by varying a bit's jet nozzle diameters. Our objective is to deliver an optimum amount of hydraulic energy through these nozzles. In addition to removing cuttings, this energy works to cool the bit.

Hydraulic energy is related to pressure loss. The pressure loss across a bit (ΔP bit) is equal to the mud pump pressure (ΔP pump) minus the frictional pressure losses in the circulating system (ΔPf)

$$\Delta P_{bit} = P_{pump} - \Delta P_f \qquad 21$$

Where ΔPf is the sum of the pressure losses in the surface equipment, drill pipe, bottom hole assembly, and annulus.

The bit hydraulics most be optimized in terms of hydraulic horsepower (HHP), impact force (IF) or nozzle velocity (V_n):

$$HHP = \frac{\Delta P_{bit} \times q}{1{,}714} \qquad 22$$

Where q = circulation rate in gal/min (U.S.); HHP is in units of horsepower

$$IF = 0.01823 \times C_d \times q\sqrt{\Delta P_{bit} \times MW} \qquad 23$$

Where: IF = impact force, lb_f

MW = mud weight (lbm/gal)

Cd = nozzle discharge coefficient, normally equal to 0.95

$$V_n = 0.32086 \times \left(\frac{q}{A_T}\right) \qquad 24$$

Where V_n = nozzle velocity, ft/sec

q = flow rate through nozzles, gal/min

A_T = total nozzle area, in^2

The pressure drop across the bit nozzles, expressed in psi, is equal to

$$\Delta P_{bit} = \frac{q^2 MW}{(12{,}031 C_d^2)(A_T^2)} \qquad 25$$

Where, Cd = nozzle discharge coefficient, normally equal to 0.95

A_T = total area of bit nozzles, in^2.

Due to the higher friction pressure that accompanies an increase in circulation rates, hydraulic horsepower or (IF) is limited by the pressure rating of the mud pumps. There are optimal circulation rates for which HHP and IF are at their maximum values.

(The *Figure below* shows: *Bit hydraulic horsepower and impact force as functions of circulation rate*). At higher rates, friction losses become excessive. We can show mathematically that maximum bit HHP occurs when:

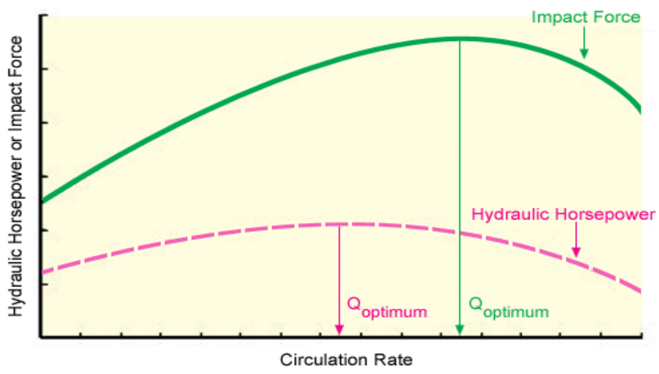

Figure -3: Bit hydraulic horsepower and impact force as functions of circulation rate

$$\Delta P_f = \frac{P_{pump}}{n+1} \qquad 26$$

and that maximum bit impact force occurs when

$$\Delta P_f = \frac{2P_{pump}}{n+1} \qquad 27$$

Where, n is a flow exponent determined from a logarithmic plot of pressure versus flow rate at two points:

$$n = \frac{log\left(\frac{P_1}{P_2}\right)}{log\left(\frac{q_1}{q_2}\right)} \qquad 28$$

3.2 Performance using nozzle velocity

We may not be able to apply hydraulic horsepower or impact force criteria on some wells, because of limited pump capacity, high friction pressures or annular velocity restrictions. In these cases, nozzle velocity becomes our optimization criterion. Maximum jet velocity occurs when a change in bit pressure (ΔPbit) is at the maximum value for some established minimum flow rate (generally the lowest flow rate needed to overcome slip velocity). however, mud circulation rate may be altered in order to affect various measurements, such as the pressure profile, the fraction of cuttings in the returning mud, or the penetration rate. A high mud circulation rate will provide a higher jet impact force through the nozzles of the drill bit. However, increasing the mud flow rate beyond a certain point will eventually increase the frictional losses in both drill string and annulus. In turn, this will reduce the jet impact force at the bit, thus increasing the drilling costs and reducing the rate of penetration. [10] A high mud circulation rate also increases the risk of mud loss if the well is overbalanced. In order to take these considerations into account in the optimization problem, the mud flow rate was constrained at a maximum of 50 liters per second. [15]

Where all other factors are constant, penetration rate tends to increase with increasing weight-on-bit. *Figure 4* (*Typical response of penetration rate to increasing bit weight*) illustrates this trend.

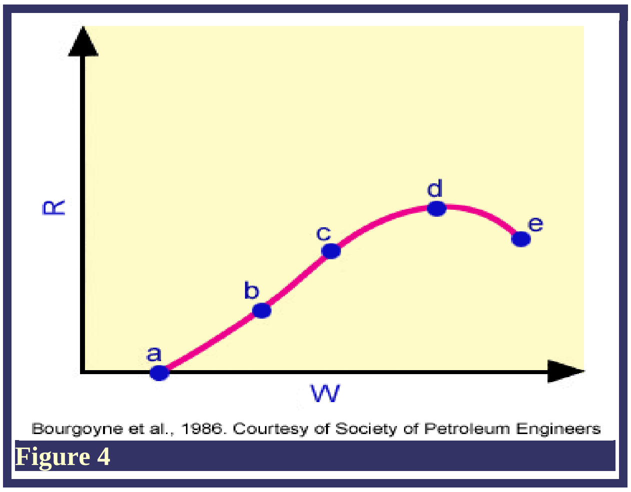

Figure- 4 Typical response of penetration rate to increasing bit weight

From Figure 4 we may observe the following:

- There is a threshold, or minimum bit weight (point **a**), below which the bit does not penetrate the formation.
- Once the driller exceeds this threshold weight, the rate of penetration increases rapidly (from point **a** to point **b**).
- Within the normal range of bit weights applied in drilling operations (from point **b** to point **c**), penetration rate increases linearly with bit weight.
- Beyond the normal operating range, an increase in bit weights results only in slight increase penetration rate (point **c** to point **d**).
- At extremely high bit weight values (or if bottom hole hydraulics are poor), penetration rate decreases, this is due to inadequate cuttings removal, or because the cutting elements are being buried in the formation. this phenomenon is referred to as bit floundering.

Over the normal operating range of bit weights, we can express the relationship between bit weight and instantaneous penetration rate as follows:

$$\frac{dD}{dT} \propto (W - W_0)a_5 \qquad 29$$

Where: W_0 = threshold bit weight which varies for different formation. For consolidated or hard rocks formations, $W_0 > 0$. For soft rocks, W_0 may be equal to zero or less, for unconsolidated formations that can be drilled by jetting or washing the hole, W_0 less than zero.

a_5 = bit weight exponent, which is constant for a given set of operating conditions.
As a rule, penetration rate increases non-linearly with increasing rotary speed (N), as shown in *Figure below*

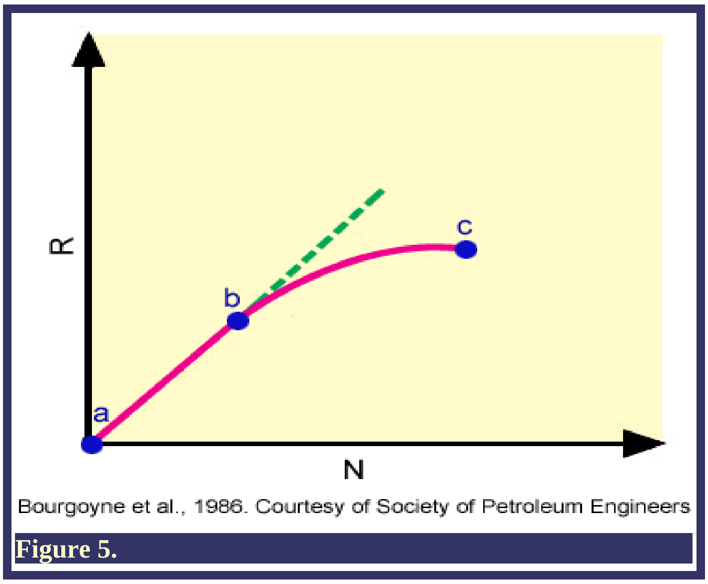

Figure 5 The relationship between instantaneous penetration rate and rotary speed

As N increases past a certain point, the penetration rate does not increase as quickly as in the case of extremely high bit weights, this is a consequence of poor cuttings removal at high rotary speeds.The relationship between instantaneous penetration rate and rotary speed can be express as follows [14]

$$\frac{dD}{dT} \propto N^{a6} \qquad 30$$

Where: a_6 = rotary speed exponent

Field tests results indicate that the rotary speed exponent's value depends on bit weight and that low bit weights result in higher values of a_6 than high bit weights. Also, as shown in *Figure 5*, a_6 approaches a value of one at low N values and decreases with increasing penetration rate.

As bit run progresses, tooth wear causes a gradual decrease in penetration rate. But bit manufacturers can minimise the effects of this wear to some certain extent by selectively hard facing the bit teeth, which results in a self-sharpening action. Hard facing, however, does not pay for the reduction in tooth length caused by abrasion and chipping. The decrease in penetration rate with increasing tooth wear is non-linear. One reason for this behavior is that each tooth, as it wears down, presents a larger cross-sectional area to the formation.

3.3 Pipe Connections and Drilling Trips optimization

In order to optimize the drilling process, we wish to minimize the pipe connection time t_c and the trip time t_t. In order to simulate the effect of a pipe connection or a trip on the drilling process, we first need to identify the procedures which take place. During a pipe connection, the top drive and mud pump must be disconnected from the drill string in order to facilitate the connection. While the main pump is ramped down, the drillers must be able to rely on the pressure control system to keep the bottom-hole pressure at its set point (minimum between its margins). Thus, a pipe connection involves the following sequence of procedures: [7].

1. Position drill string to roughneck position
2. Stop drill string rotation
3. Engage slips
4. Ramp down main mud pump
5. Perform physical connection
6. Ramp up main mud pump
7. Release slips
8. Start drill string rotation
9. Trip in drill string to bottom of the well

A drill trip involves a full drill string retraction from the well. Thus, it may be viewed as a series of one stand of pipe retraction and performing a reversed connection procedure. The speed of tripping operations and pipe

connection is normally dependent on certain criteria that must be assumed to require a time constant, such as the physical connection procedure. The speed of other procedures, however, such as ramping the main pump up or down and tripping the drill string in or out may be improved. The bottom hole pressure is affected by changing the mud circulation rate or the drill string position. Therefore, it is significant that these procedures are carried out quickly (to minimize the cost), but without causing excessive upset to the bottom hole pressure.
So, to facilitate optimal operation of drilling trips and pipe connections, it is important to automatically control the mud flow rate and drill string velocity rather than manually controlled by the drillers. It would be optimal to configure automated sequences for pipe connections and trips that could be initialized by the operators.

3.3.1 Operational Constraints

There are several constraints that need to be considered during drilling, both for measurements and for inputs. The most important constraints are the pressure constraint, bit weight, and rotary speed constraints. The bottom hole pressure must be controlled within its limits very effectively.

3.3.2 Active Constraints

The active constraints in the optimization are the lower bottom hole pressure constraint and the upper mud circulation rate constraint. It is significant to control the constraints that are very active at the pig to ensure optimal operation. The control of each active constraint consumes one manipulated variable (MV). We assume the bottom hole pressure is controlled using the choke pressure (pc) and thus omit the choke pressure and the mud flow rate from further analysis.

3.3.3 Bit Weight & Rotary Speed Constraints

Optimal penetration rates do not necessarily occur under conditions of maximum bit weight and rotary speed. Indeed, such conditions can sometimes result in bit floundering due to inefficient cuttings removal. This shows that there are practical limits on bit weight and rotary speed. These limits include:

- *Hydraulics*: The penetration rate must not overwhelm the system's circulation ability to clean the hole and condition the mud. Also, it must not be too high as to make kick detection difficult. These conditions assign limits on how fast we can drill (and thus on our bit weight and rotary speed).
- *Hole deviation:* Excessive bit weights may cause doglegs or other crooked hole problems. But this limitation can overcome to a large degree, by properly designing the bottom hole assembly.
- *Bit specifications*: Bit manufacturers design their products specifications to run within certain ranges of bit weight and rotary speed. But any attempt to operate outside the established ranges can result in inefficient drilling or even damage to the bit. The manufacturer's agent can provide the required specifications and recommend bit types for certain drilling conditions.
- *Cost per drilled depth:* This is the most important limiting criterion on operating conditions. Maximum penetration rates do not always result in minimum cost drilling. The footage and bit life parameters that result from various weights and rotary speeds must be substituted into the cost per foot equation to provide a true indication of optimum conditions.

4.0 CONCLUSION

This paper involved an extensive search for drilling literature review, in order to learn the basic problems and the challenges that are faced during drilling operations. The result shows that many parameters are involved in the drilling process, and deviation of one factor may lead to hole cleaning issues and other problematic situations.
One of the main reason of introducing this method is to advise the user on how to deal with the controllable drilling parameters with respect to the associated basic cause. Whenever the cause of a problem is known, the proper remedy can be applied. ‘Hole Collapse’ is one of the major causes of poor hole cleaning, mostly resolved by adjusting the density of the drilling fluid (mud).

Most of the drilling equations used in this paper are empirical that require estimated parameter for a large number of parameters. These estimates were made based on reported values in drilling literature, as well as a trial-and-error method to obtain a realistic drilling results from the equation model . The cost function, of the drilling process was determined on the basis of drilling literature, reasoning and analysis. It was aim to reflect all parts of the drilling process, not only the active drilling time. The cost function analysis led to the separation of the drilling operations into two operating modes: The Active drilling operations, and the pipe connections and drilling trips. This is done because of the difference in control objectives. Hence, their optimization was analyzed separately.
The drilling process was optimized for given parameters representing the drilling conditions. The
constraints on the bottom hole pressure and mud circulation rate were active at the optimum. But these active parameters were removed from further analysis because the bottom hole pressure was controlled by the choke pressure, while the main mud pump flow rate was kept constant.

For single measurement controlled variables, the results show that it is optimal to control the top drive power by manipulating the drill string rotational speed and keep the weight on bit (WOB) constant. The combination of several measurements will give a minimum loss, with an increase in the complexity of the control structure.

Further work

As the drilling process involves many challenges and complications that make it difficult to assess the process completely and take everything into account. The paperwork has been carried out with little practical experience on drilling processes, thus given more priority on extensive drilling literature work to obtain realistic drilling results from the equation model. Further studies of the drilling process and industrial experience would undoubtedly result in a more detailed drilling model, improving the accuracy of the results. And it would be interesting to apply the results of this paper in real-life drilling operations to ascertain its integrity.

Lastly, the minimum cost per foot was determined for a specific set of operating conditions without addressing the issue of how these conditions might have affected the bit run. It is suggested that different set of conditions should be tested perhaps may result in a better drilling performance and lower cost per foot.

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