Design of Continuous Gauge Near-Bit Stabilizer, Using Optimized Hydraulics and Gauge Geometry in Mishan andAghajari Formation

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Abstract

The main task of drilling the formation by the bit is done via scraping, crushing and grinding. Discharging the fluid from the bit nozzles is done with high pressure which assists to break the rocks. Different parameters affect the bit selection and design for each drilling formation, but the most important one is drillability that depends on hardness of the formation. In this paper, the design of continuous gauge near-bit stabilizer and a novel drill bit design was evaluated by optimizing the hydraulics and gauge geometry. It was found that the design is appropriate for the Aghajari and Mishan formations as the drilling efficiency could be increased. Moreover, some problems of drilling in this formation such as bit balling and high wearing were largely reduced by the presented model.

Keywords:Bit, Drilling, Failure, Gauge, Hydraulic, Soft formation

Introduction

Drag Bit is the first bit that has been used in rotary drilling. This type of bit has strong steel blades that are in the shape of fishtail, laminates the formation and its efficiency in the soft formation is more thantheothers. Bit nozzles have been mounted so that exit of mud with pressure continuously cleans the blades. Bit is integrated and its blades have been coated with tungsten carbide [1]. Since the formation failure mechanisms are scraping and chipping, high RPM and low weight on bit is required for drilling by this type of bit in order to increase the efficiency. Nowadays this type of drill bit has been abolished and Roller Cone bitis used instead of it for the following reasons [2]:

- Drilling of soft formations with roller cone bits has higher efficiency.
- Too much weight on the bit causes to dive the blades into formation, increasing the bit torque and the possibility of cutting the drilling pipes.
- Drilling with drag bit may cause well deviation from the main direction and the tool in the BHA should be used to prevent this problem.
- Drag bit is used in drilling of soft and homogeneous formations and it is not applicable in hard and abrasive formations.

In this paper, the drilling mechanisms by roller cone bits in the soft formations of Iran such asBakhtiari, Aghajari and Mishanis studied and strategies that improve the drilling operation and increase drilling speed are evaluated.

1- Geological information of southern areas of Iran

1-1- Aghajari formation

This formation belongs to the third geological era (Pliocene - Miocene) and its components are grayish brown cement maker sands, valley makermarls, silt and marl with thin streaks of gypsum. Most sandstone are chert grains and include red Marls to brown and sometimes gray withthesandstone layers which alternately are seen within them. Because of soft nature of this formation, roller cone bits (with large teeth) are oftenused for drilling.Due to the fractures presence in the sandstone and

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limestone layers in some areas, drilling is encountered with intense loss circulation which can be controlledwith pumping of LCM (Lost Circulation Material). As a result of the clay minerals, washout of the well occurs in this formation, so toprevent the associated problems, this formation must be immediately drilled and cased.The thickness of this formation is 2966 m.

1-2- Mishan formation

This formation belongs to the third geological era and is generally composed of gray marl, silt, and calcareous streaks. The calcareous streaks are more in the lower parts of the formation. In the Fars province these calcareous rocks has formed Gori section that is a gas reservoir. The lower part of this formation is composed of the cream limestone and gray marls and between them the alternating of the reef limestones is seen.The thickness of this formation is about 710 m.

2- Failure mechanisms in the Aghajari and Mishan formations

Aghajari formation has a linear elastic behavior because of the nature of constitutive materials. But due to the existence of clay and especially chert conglomerates, its behavior will not be linearly elastic until the failure point and with high stress, greater strain is created and because of the presence of this mineral and structure, it also adopts the plastic behavior. In better interpretation, failure mechanisms of Aghajari formation will be elastic-plastic. Stress - strain diagram of Aghajari formation are shown in Figure 1.

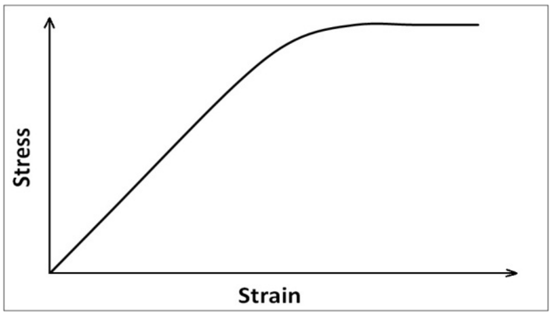

Figure 1: Stress - strain diagram of Aghajari formation

Marls makeMishan formation divulges because of their naturethe plastic behavior at first but this behavior is very transitory, and Mishan formation has predominantly elastic behavior. Mishan formation generally has plastic-elastic behavior (Figure 2).

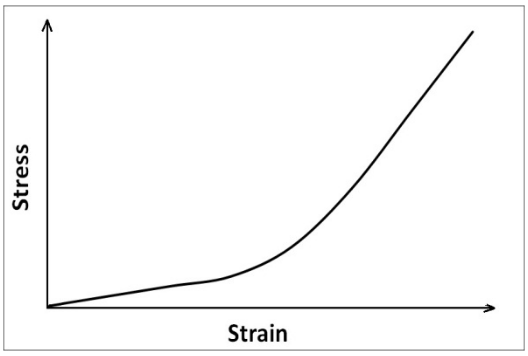

Figure 2: Stress - strain diagram of Mishan formation

According to Elastic-plastic behavior of Aghajari formation and Plastic-elastic behavior of Mishan formation, their diagram of stress - strain werepresented in the Figure 3,regardless of the initial plastic behavior.

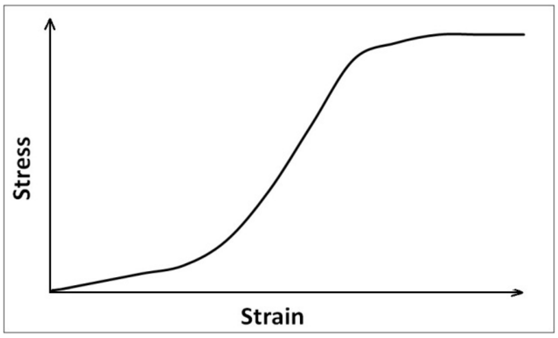

Figure 3: Stress - strain diagram of Mishan and Aghajari formations

3- Effective parameters in the drilling speed

The following parameters affect drilling speed:

- Formation properties
- Mud drilling properties
- Mud drilling Hydraulic
- Type of bit
- Weight on bit
- Rotary speed of bit
- Bit teeth wear

Relationship between some of the above parameters with the drilling efficiency is also unknown; thus selection of a comprehensive model fordrilling is often encounters problems. Sometimes with laboratory modeling of well conditions the effect of each parameter on the drilling speed can be considered. However, the obtained results are applicable for a particular area and a certain kind of formation and in other conditions may not be valid. Some effective parameters in drilling speed are out of control, and it is not possible to optimize them. For example, the formation properties cannot be changed.

3-1- Type and properties of formation

Most important properties of the formation which has effect on the drilling speed are: compressive strength, yield point, porosity and its permeability. If formation porosity and permeability are increased the drilling speed will be decreased and if formation compressive strength is increased the drilling speed will be decreased.

3-2- Mud properties

If the mud weight is increased, mud column and formation pressure will be increased which results in keeping the drilling cutting at the bottom hole. Not cleaning the bottom hole from drilling cutting reduces drilling speed. Other property of the drilling fluid that affectsthe ROP (rate of penetration) is viscosity. If fluid viscosity is increased drilling speed will be reduced. Clay drilling usually increases drilling mud viscosity. Solid particles percent of drilling mud also reduces the ROP [3].

3-3- Type and size of bit

Correct selection of the bit according to the type of formation has high impact on the drilling speed. For soft formation drilling roller cone bits with large teeth are applied and using a drag bit in this formation reduces drilling speed. API according to formation provides tables to select the type of bit that is the bestforeach formation [4].

As it was mentioned, formation properties can not be controlled. Mud properties and bit types are optional and controllable, but should be fixed during the bit run. When a bit runs into the well it may drill different formations. In the same way, we cannot change the drilling mud for each formation because of its high costs. Thus, it can be said that the formation, bit and mud parameters are out of our control during the drilling and we can maneuver on other parameters, hydraulics, weight on bit and its rotary speed.

3-4- Hydraulic

If drilling speed is increased, amount of generated drilling cuttingswillbe increased, thus more hydraulic power is required for transmitting the drilling cutting to the surface. If the drilling cuttings are not transferred to the surface on time, these cuttings will indwell around the drill bit (bit floundering) [5]. In other words cuttings bury the bit in themselves and much of the bit energy is spent for re-breaking of these cuttings. With size design of bit nozzles, the required hydraulic energy for transferring the drilling cutting can be provided.

$$\Delta P_{bit} = P_{pump} - \Delta P_f \tag{1}$$

$$HHP = \frac{\Delta P_{bit}.q}{1714} \tag{2}$$

IF=Impact Force (lbf) = 0.01823 Cd.q.×

$$\sqrt{\Delta P_{bit} \times MW(ppg)} \tag{3}$$

$$V_N = 0.32086\frac{q}{A_T} \tag{4}$$

ΔP_f = summation of pressure drops in the surface equipment, drill pipes, BHA and annulus

q =Mud flow rate (GPM)

ΔP_{bit}= Pressure drop of bit (Psi)

HHP = Hydraulic Horse Power

C_d = Nozzle Discharge Coefficient = 0.95

V_N = mud velocity in the nozzles (ft / sec)

A_T = total area of nozzles (in^2)

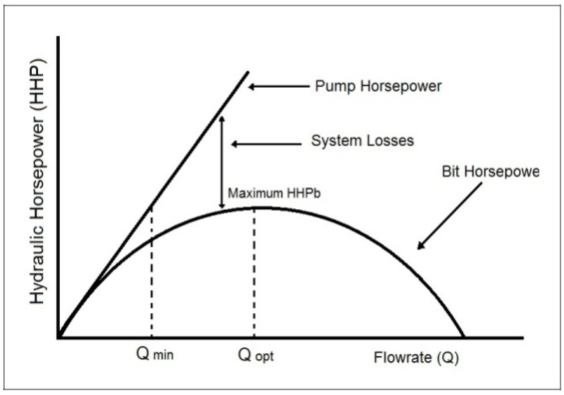

Figure 4: Consumed power of drilling string and bit

To have the strong hydraulics, ΔP_{bit} must be increased. If so, IF will be increased and consequently ROP will alsobe increased. In a rig, there are specific pumps that can pump certain flow rate so that V_N must be optimized [6].

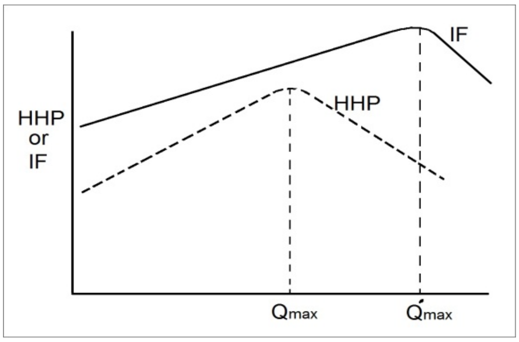

Figure 5: Relationship between HHP and IF with flow rate

As it has been expressed in the above formulas that if q is increased, HHP and IF will be increased, but in fact the trend may be not like that. The above graph shows that with increasing q to a certain amount, HHP (Φ_{max}) and IF are increased. Since then, because of increase in pressure drop due to friction (ΔP_f), their values will be reduced.

It can be mathematically indicated that the maximum amount of HHP occurs in conditions that:

$$\Delta P_f = \frac{P_{pump}}{n+1} \tag{5}$$

Also maximum value of IF occurs when:

$$\Delta P_f = \frac{\Delta P_{pump}}{n+2} \tag{6}$$

n = Flow Exponent =

$$\text{Log}\left(P_1/P_2\right)/\text{Log}\left(q_1/q_2\right) \tag{7}$$

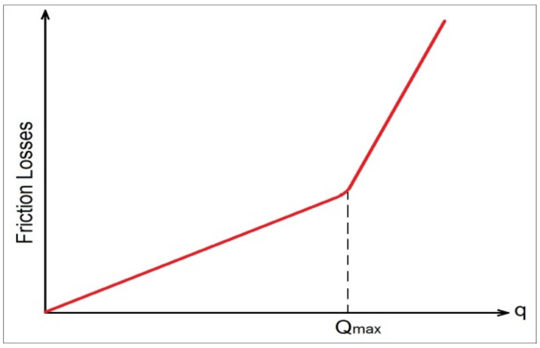

Figure 6: Relationship between friction losses with flow rate

3-5- Weight on the bit

The effect of weight on bit on the drilling velocity is different in various rocks. Sometimes in very soft formations drilling is performedwith mud hydraulic energy andwithout applying the weight on the bit [7]. Generally, the effect of weight on bit on drilling velocity has been shown in the following figure.

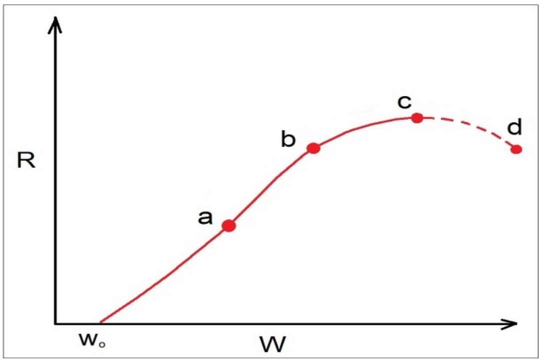

Figure 7: Effect of WOB on drilling speed

- W (Initial Weight) is the minimum weight on bit to sink the bit teeth into the formation and to start drilling.
- With increasing the weight on bit from the amount of W, drilling velocity quickly rises (from point a to b).
- From the point b to c changes of drilling velocity and weight on bit are linear.
- Increasing the amount of weight on bit from W_d does not just increase the drilling velocity. But because of the bit floundering phenomenon the drilling velocity is reduced.
- The best conditions for drilling are applying weight on bit in the range of b to c.

3-6- Rotary speed of bit

Drilling and penetration in rock is a result of contact between the rock and bit. If the number of contacts in a unit of time is increased, the amount of the applied energy from bit to rock will be increased and consequently drilling speed will be increased. Thus, if rotary speed of bit is increased, the drilling speed also will be increased [8]. But there is no linear relationship between these and to a certain RPM drilling speed increase is evident. Since then, the rotary speed increase has no impact on the ROP. This is because the cuttings are not removed on timefrom the well during the drilling and cleaning the well is not performed well. On the other hand, excessive RPM causes loss of bit teeth and its quick wear.

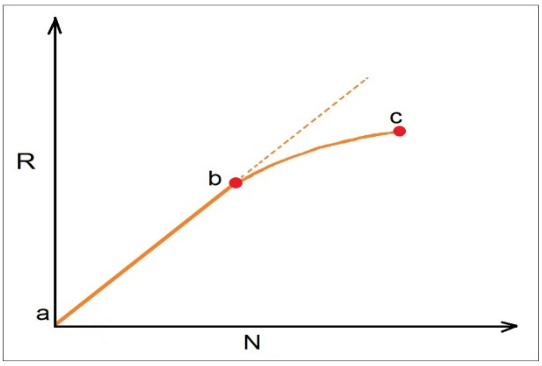

Figure 8: Effect of rotary speed of bit on the drilling speed

3-7- Bit teeth wear

With wearing the bit teeth formation contact area with the bit is increased. In fact, area of tooth that must penetrate into the formation is increased [9].This requires a greater weight on bit so that the speed drilling remains optimum. This leads to bit depreciation and decrease of useful life of bit.

4- Bit design for Aghajari and Mishan formations

From the perspective of bit, designs are performed in a way that reduces the amount of bit balling. This occurs in a place where drilling cuttings are accumulated together and stick to drill bit and will lead to decrease in drilling efficiency. Solutions may include optimizing the open face volume, though potentially at the cost of reduced durability of the designs.

To check the soft formation, one of the most important parameters is hydraulic. Firstly, usefulness of the hydraulic is reverted to the bit hydraulic power and effect of its jet force. Its accepted aspects are for the soft formation drilling which the flow rate is maximized to optimize the bit and clean the well; although there are many documents that have presented the optimized structures of nozzles for both types of roller cone and fixed cutter.

Aside from the drill bit, soft formation applications can also cause issues with BHA components that will affect both stabilization and directional control. Balling of a stabilizer will increase the chance of swab or surge pressure problems thus may lead to selection of straight bladed designs. A major challenge to directional success is the hole washout, in this mood the support from the borehole wall for a stabilizer is very poor. This significantly reduces directional control and string stabilization of the assembly. In addition, soft formation drilling reduces the control of drilling parameters. The best example for this purport is that the bit penetrates through the rock, even with low weight on bit (WOB) yields high rates of penetration (ROP) [10]. These are usual challenges for drilling operation in soft formation. This paper reviews three distinct solutions that have been developed to overcome these issues, focusing not just on the bit but also on the stabilization of the string.

4-1- Continuous Gauge Near-Bit Stabilizer

The rotary directional sub (RDS) was developed for specific point-the-bit RSS's to improve both lateral stability and steerability of the directional system. Aside from improved drilling performance, the intention was also to prolong the life of both tool and drill bit, particularly in harsh drilling environments. The design incorporates a four-bladed steel stabilizer, with box-up and box-down connections. The blades follow a right-hand pitch to provide 100% spiral wrap. The unique aspect of the RDS is the use of a full ring located at the uphole end of the stabilizer (Figure 9).

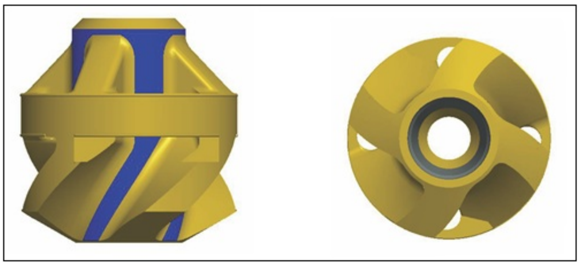

Figure 9: Face and side view of the Rotary Directional Sub

For strength and durability, the RDS is machined from a single piece of steel. The overall gauge contact includes both the spiral blades and ring area. Overall length and diameter is engineered to provide optimal directional control matched to the specific hole size drilled.

The lateral stability benefits of the gauge ring design, when incorporated into fixed cutter drill bits, are well documented. Using the directional stabilizer will also have distinct advantages:

- Full 360° circumferential gauge coverage provides resistance to off-center rotation and reduces lateral vibration.
- The ring gauge provides a continuous bearing contact surface for deflection against the borehole, thus maximizing the deflection force imposed by the RSS and limiting any tendency of the blade's leading edges to underream and therefore enlarge the borehole. This continuous contact surface will be advantageous over spiraled-blade geometry, as even with high pitch angles, the blades still do not provide a continuous contact at the fulcrum point. Both these points will benefit steering for directional tools that have critical dependence on borehole contact.
- Full, 100% gauge contact will be advantageous in reducing drop tendency in high-angle tangent sections, particularly in soft formation applications.
- It is effective for both fixed cutter and roller cone designs and is fully flexible in the field to allow optimization and customization of the bit / RDS assembly to optimize drilling performance.

4-2-Novel Drill Bit Design: Optimized hydraulics and gauge geometry for soft formations

Polycrystalline Diamond Compact (PDC) bits are successfully run in a variety of lithologies ranging from soft through to hard. There are several key factors that are attributed to their continuing success including recent major step changes in both cutter technology and stabilization. Hydraulics also significantlycontribute to the overall performance of the design due to their critical role in issues such as bit and bottom hole cleaning, as well as cooling of the cutting structure. In very soft formations, the hydraulics also appear to play a major role in directional performance; if hydraulics are not optimal they can either result in balling of the drill bit and stabilizers, or hole washout and loss of borehole contact with the directional components of the BHA [11].

4-2-1 Hydraulics

Garcia-Gavito et al conducted a series of tests investigating the hydraulic effect from changing nozzle sizes and positions with PDC drill bits. One particular test of interest was conducted with a design with six nozzles, three located in the center of the drill bit while the other three were located towards the gauge of the bit. Pressure distribution under the bit was evaluated with 1) all six nozzles open 2) three outer nozzles blanked and central nozzles open and 3) central nozzles blanked and all three outer nozzles open. It was discovered that when just the central nozzles were open it approximatelydelivered a 27% increase in ROP when compared to the assembly with just outer nozzles open. This was attributed to a higher crossflow fluid velocity allowing faster cuttings removal and lower differential pressure applied to the formation.

These findings were reviewed when considering the hydraulics for this 9 ½” application. The optimal scenario is one that allows for efficient cleaning of the cuttings but minimizes borehole washout. As such, three very large central nozzles were utilized in the center of the drill bit design, each being able to accommodate a 1” jet. This allows for maximum flow around the cutters on the bit face and minimal flow over the borehole sidewall. This provides good crossflow fluid velocity for efficient cuttings removal from the face, with reduced risk of hole washout when compared to a more conventional nozzle configuration i.e. equal nozzle sizes at varied radial distribution (Figure 10).

Figure 10: Conventional nozzle arrangement

Due to potential balling concerns, six smaller jets (12/32”) were also added at the nose radius of the bit design to provide additional cleaning capability. As per the central nozzles, these were directed away from the borehole to minimize hole washout (Figure 11).

As can be observed, with this novel hydraulic arrangement, the shear stresses at gauge are practically zero. This minimizes the risk of borehole erosion, delivering both improved steerability and borehole quality.

Figure 11: Centralized Nozzle arrangement

4-2-2 Gauge geometry

It was decided to incorporate a continuous ring gauge rather than discrete pads as seen on conventional bits (Fig 12).

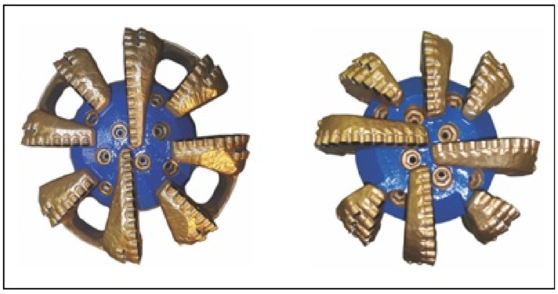

Figure 12: Ring gauge (left) geometry compared to conventional gauge pad (right) design

Ring bits were designed to improve directional response by improving the lateral stability of the bit, reducing the propensity of the bit to whirl. In addition, the ring gauge minimizes side cutting from the cutting structure, facilitating a smoother, gauge borehole. The actual geometry provides a large surface area at gauge for efficient deflection when steering as well as resisting drop when in the horizontal section. The gauge design was also tapered, which has been proved to be effective for reducing torque and drag on both push and point RSS.

5- Conclusion

According to the investigations, the Aghajari and Mishan formations have elastic and plastic properties. So,designingthebits that are capable for drilling of these formations with longer life and lower operating costs, can dramatically increase the drilling efficiency. Some of the problems of drilling in soft formations are bit balling, high wear, washout, non-controllability of different parameter like ROP which these problems will be reduced largely by this design. Various parameters have effect on the speed and efficiency of drilling,amongwhich rock properties, mud hydraulic, type of bit and WOB are the most important ones.

Mud Hydraulics has high impact on rock failure, cleaning the wells and the drilling speed, so, location and size of the nozzles are changed to optimize the mud hydraulics. If hydraulics are not optimal,itwould either results in balling of the drill bit and stabilizers, or hole washout and loss of borehole contact with the directional components of the BHA.

Another factor that must be optimized in bit design is gauge geometry. To optimize the gauge geometry, it has been decided to incorporate a continuous ring gauge rather than discrete pads as seen on conventional bits.

The rotary directional sub (RDS) was developed for specific point-the-bit RSS's to improve both lateral stability and steerability of the directional system. Aside from improved drilling performance, the intention was also to prolong the life of both tool and drill bit, particularly in harsh drilling environments. The design incorporates a four-bladed steel stabilizer, with box-up and box-down connections.

According to the Aghajari and Mishan formation and their rock behavioral characteristics, the bit Centralized Nozzle arrangement is designed and as it was verified byJohnson (2006) in order of costs, it is accepted for final design as a suitable bit.Nowadays this type of bit is mostly used in rotary drilling in the world and high performance and efficiency has been observed. Thus, this design will definitely improve the drilling operations in Aghajari and Mishan formations.

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