Well Deviation Problem: A Case Study in an Iranian Gas Well Drilling

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Abstract: Unexpected well deviations can bring the drilling projects lots of financial and technical damages. As a result, investigation of the Bottom Hole Assembly (BHA) tendency and prediction of the probable mechanical behavior of the drilling string, especially when a new configuration is running in the hole, is critical to prevent unexpected failures. In this paper, a drilling project in an Iranian gas field which ended in a catastrophic well trajectory is going to be studied in more detail. Here, we try to answer three main questions. The reasons for the unusual well trajectory and the possibility of predicting this behavior is the first issue. The second question is about the signs of this failure during the operation and the ways that we could detect it earlier. In the third question, the alternative plans that can prevent this problem are examined by studying different BHA configuration and drilling parameters. The major sources of our information are the daily drilling reports, well log data, related published articles, and numerical simulations in WELLPLAN™ software of Landmark package.

According to the simulation results, BHA design is one of the most effective factors in this case study and its effect could be predicted using BHA tendency analysis before starting the drilling operation. During drilling of this well, some anomalies have been observed in drill string mechanical parameters such as hook load, rotation torque and up and down drags. Simulation of torque and drag charts for some probable well trajectories shows completely different trends for the expected well trajectory and the actual one. The observed data during the drilling operation are similar to the ones simulated for a highly deviated well and are completely unlike the trend of the near-vertical well path. Hence, it was possible to detect the wrong situation if we had simulated the mechanical behavior of the drill string and compare it with the actual observations during the operation. Finally, examination of various BHAs reveals that using an in-gauge stabilizer 10 meters above the bit instead of the one that is 20 meters above the bit could provide better well path control. It is completely obvious from the different build and walk rates which resulted in about 19 different BHA configurations. Moreover, the suggested BHAs demonstrate a good tolerance in case of changing WOB in the desired range. In the end, besides from being careful and alert during the drilling operation, the application of credible drilling simulators is strongly recommended in order to prevent unforeseen situations and also to be prepared if some happen.

Keywords: Well deviation, BHA tendency, Torque and drag analysis, Drilling stabilizer placement, Drilling parameters.

1. INTRODUCTION

Control of borehole direction during oil and gas well drilling can be difficult and costly. Unintentional deviated holes are often drilled in dipping formations. Drilling progress can be diminished when applying low bit weight in order to prevent excessive hole, angle build-up. In highly deviated wells, drill string torque and drag will be excessive and fishing risks are increased, logging is more difficult and the problem of differential sticking, key seating and fatigue failure is more probable. Dog-legs and key seats are more serious problems than steep constant inclination angles. Therefore, reducing the rate of direction change is preferred to attempting to maintain absolute vertical holes and a straight inclined hole is preferable to a nearly straight crooked hole with many dog-legs [1]. Some researchers have shown that a large portion of the time lost due to well-bore deviation can be recovered only by considering two readjustments in the accepted policies. First, some degrees of well inclinations appropriate with the characteristics of the area must be accepted by the well owners. The second practice to be considered is the use of Bottom Hole Assembly (BHA) and drilling parameters that restrict the change of hole direction as great as possible [2].

The possibility of well deviation should be considered before proposing any well drilling program especially when a new BHA is going to be applied in a field. Ignoring BHA analysis and inappropriate well surveying can lead to unwanted well trajectories. Sometimes this may end in an economic disaster in a drilling project. In this paper, the case of drilling a gas well in a gas field of Iran is going to be reported where a very strange well trajectory was created that caused many technical and financial problems. Here, we are going to investigate this problem in more detail and explain the main reasons, the early signs and the ways that we could prevent the problem. The main sources of information in this research are the daily drilling reports and recorded logs of the well, previously published articles and the numerical simulations which have been performed in WELLPLAN™ software of Landmark software package (developed by Halliburton). It should be noticed that according to the National

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Iranian Oil Company (NIOC) policy we cannot mention the name of the well, the gas field, the drilled formations and detailed financial information. However, we have tried to include the essential data in order to clarify the problem as much as possible and propose more realistic conclusions. In the text of this paper, we will refer to the gas field as Field-S and name the well as well S-16, which are not, of course, the real names of the field and the well.

The rest of the paper is organized as follows: the summary of the drilling operation is presented in section 2. In section 3, a brief literature review of BHA analysis and some theoretical backgrounds are presented. Numerical analysis of BHA behavior in well S-16 is performed and reported in section 4. In this part, we aim to explain the reasons for the problem, the ways that we could recognize it in the earlier stages of operation, and the alternative plans that could prevent or alleviate the failure. Finally, the main conclusions of the study are summed up in section 5.

2. DRILLING OPERATION SUMMARY OF WELL S-16

The drilling of well S-16 was started using 17-1/2" rock bit and continued to 69 m (13-3/8" casing point). Using a hole inclinometer (Totco chart), the well inclination was measured 0.75 degrees at 67 m. After 13-3/8" casing, drilling continued to 155 m using 12-1/4" rock bit & without any stabilizer. The borehole inclination at 153 m was measured 1 deg. In order to prevent more inclination from the depth of 155 m, two joints of stabilizers were added to the BHA at 20 m and 30 m above the bit. Drilling the formation was resumed to 1255 m while inclination was recorded as 4.5 degrees in 760 m and 1245 m. 8-1/2" bore-hole began to be drilled with 8-½" rock bit & no stabilizer in the BHA from 1255 to 1260 m and then drilling resumed applying a PDC bit, 6-½" drill collars and two joints 8-1/2" stabilizer in 20 m & 30 m above the bit. The 4.5 degrees inclination was recorded at the depth of 1530 m using a Totco chart inclinometer. During the first condition trip, an unusual over-pull was experienced at 1345 m which was considered as a tight-hole condition and so reaming operation was done several times. After that, during drilling, an abnormally high torque and oscillation in drill string rotation were observed in depth of 1760 m. Consequently, the drilling string was pulled to 1253 m (casing shoe) and the string rotation torque was checked which was normal. Running in the hole from 1615 to 1761 m was done with string rotation and abnormal torque oscillation. Due to the experience of tight-hole conditions in nearby wells, it was decided to increase mud weight from 80 to 83 pcf and continue drilling the formation. The drilling operation was continued to the depth of 2712 m while gradually mud weight was increased to 103 pcf due to high torque and tight hole during drilling and string connections. Finally, it was decided to stop the drilling because of unexpected high torque (10000-12000 lb-ft) and also mismatch between formation samples in this depth and geological forecast (about 250-meter difference in observed samples and predicted ones). Try to improve the bore-hole condition by reaming different intervals. However, high drag (80-100 Klb) in reaming and high over pull (60-70 Klb) and pipe stuck were observed during condition trips. The mud weight was also increased to 113 pcf, but no improvement was observed. At last, the probability of well deviation was considered. In order to investigate this possibility, CDR/GR log and Gyro log were run in the hole and the results were really shocking!

CDR/GR log was run to 1547 m and since the cable tension was dropped at this depth (logging tools were laid on wellbore) no more progress was possible and the well survey was recorded down to this depth. The numerical data are summarized in Table **1**.

Table 1: Summary of Numerical Results of CDR/GR Log

Measured Depth (Meter)	Azimuth (Degree)	Inclination (Degree)
100	16.62	0.26
200	163.21	1.36
300	173.18	2.61
400	178.33	3.05
500	187.42	3.95
600	174.56	4.58
700	177.41	5.09
800	180.59	4.60
900	188.85	4.58
1000	170.68	5.11
1100	189.05	5.74
1200	154.71	5.32
1300	352.50	6.50
1400	356.70	12.66
1500	359.85	19.53
1547	0.66	22.80

As it's obvious from CDR/GR data, the well has a relatively constant inclination (4.5-5.5 deg.) from 700 to

9-5/8” casing shoe. However, from 1300 m (about 50 m below casing shoe) the well inclination has starts to increase with a constant build-up rate of around 1.8 °/100 ft. Since there was a considerable difference between inclinations measured by Totco and CDR log at the depth of 1530m (4.5 degrees by Totco chart and 21.5 degrees by CDR), it was ordered to run Gyroscopic survey tool through drill pipes in order to confirm CDR/GR data. It was also demanded to record more survey information from deeper parts of the well.

The Gyroscopic survey tools were set up and run through drill pipes to 1845 m. The cable tension was dropped at this depth and no more logging progress was possible. The Gyroscope survey numerical data are summarized in Table **2**.

Table 2: Summary of Gyroscopic Survey Tool Numerical Outputs

Depth (Meter)	Inclination (Degree)	Azimuth (Degree)	Northing (Meter)	Easting (Meter)	TVD (Meter)
100	0.88	3.45	1.04	-0.13	97.19
200	1.79	15.65	3.44	0.32	199.86
300	2.38	5.91	6.84	1.19	299.84
400	3.33	4.53	11.77	1.73	399.70
500	3.76	4.45	17.92	1.98	499.49
600	4.51	8.14	24.76	3.06	599.21
700	5.14	12.31	33.36	4.50	698.87
800	4.56	17.42	41.86	6.68	798.47
900	5.00	20.01	49.64	9.30	897.96
1000	5.56	15.55	58.86	12.04	997.51
1100	6.19	11.04	70.24	13.64	1096.79
1200	6.00	7.78	81.79	14.51	1196.11
1300	7.20	2.73	93.98	14.06	1295.40
1400	12.94	1.99	112.11	13.79	1393.56
1500	19.82	0.73	140.30	14.68	1489.06
1600	27.23	358.44	179.97	14.48	1580.90
1700	34.38	357.94	231.60	12.80	1667.36
1800	40.72	0.79	294.38	11.13	1748.02
1845	45.16	2.62	325.47	11.80	1781.46

It’s evident from the results that Gyro outputs have confirmed the CDR/GR measurements. The Gyro survey shows 1.97 °/100ft as an average build-up rate in the interval of 1300 to 1550 meters, which is close to the one that CDR/GR recorded. The inclination build-up rate in the interval of 1550 to 1845 meter is about 2.3 °/100ft which proves an increase compared to the upper parts of the well. Therefore, it can be concluded that the well deviation may be more than 90 degrees (around 102 degrees) at the end of the well if we suppose a constant build-up rate of 2 °/100ft down to 2700 m. This conclusion may not be far from the truth if we consider the high torques and drags and stuck pipes that we had experienced during drilling and tripping in lower parts of the well. The other conclusion from these measurements is that the well deviation recorded using Totco inclinometer at the depth of 1530 m was erroneous. The reason for this failure is that the charts used in this instrument were limited to record 8 degrees inclinations and since the real amount (21 degrees) was far from this limitation, the recorded data in the chart is not valid at all. Unfortunately, this fact was known after the disaster.

In the end, the well was plugged back to 1270 m using a cement plug and it was side tracked from 1276 m. Drilling the vertical well in 8-1/2” hole was continued using PDM and MWD tools in order to control well deviations. The section target depth was announced by the well site geologist at 2636 m. Trip in the hole was done with good condition and CDR/GR was run to get a survey from 1200 to 2639 m. Finally, 7” casing was run in the hole without any problem. The result of the final CDR/GR log showed that the maximum deviation in the new borehole was 3.5 degrees, as the deviation had been controlled by PDM and MWD.

The next hole section (6-1/8” hole) was drilled as it had been designed without any problem. However, the unexpected well deviation in 8-1/2” hole caused about 20 days of operation delay and extra costs regarding well plug back and drilling using directional drilling package (PDM and MWD). As a result, here we have decided to study this problem in more detail and try to find answers of the following questions concerning this experience:

1. What were the main reasons for such an unexpected well deviation? Can we predict it or not?

2. What were the signs that we could detect this problem earlier and reduce extra expenses?

3. How can we prevent this failure? Can we propose a better drilling plan to avoid such a costly problem?

In the following sections, we are going to collect more evidence and scientific information in order to answer logically the questions.

3. FACTORS AFFECTION BOREHOLE DEVIATION IN VERTICAL WELLS

There are some valuable papers in which theories of bore-hole deviation and analysis of drill string behavior under down-hole conditions are summarized [1]. The first significant work in this field has been referred as the efforts of Lubinski and Woods in the 1950s [3-7]. Lubinski considered the buckling of a drill string in a straight vertical hole. It was concluded that very low weight on bit must be applied to prevent drill collar buckling and consequently control the well deviation [3]. The use of conventional stabilizers was proposed in 1951 by MacDonald and Lubinski in order to be able to apply more bit weights without drill collar buckling [4]. Lubinski and Woods pointed out in 1953 that perfectly vertical wells cannot be drilled even in isotropic formations unless extremely low bit weights are applied. They concluded that constant drilling conditions lead to constant inclination angle and changing the condition will result in a new equilibrium angle [5].

The concept of an anisotropic formation was introduced as an empirical method for explaining actual drilling data and as a means for extrapolating known deviation data to other conditions of bit weight, drill collar size and clearance. In 1954, Lubinski provided practical charts to compute equilibrium bore-hole angle in straight inclined holes [6]. In 1955, Woods and Lubinski computed the additional weight which can be used without an increase of bore-hole angles by employing the stabilizer. They also determined the optimum location for stabilizer [7]. Lubinski also computed the effect of dog-legs on fatigue failures of the drill pipe and suggested a method for measuring dog-leg severity. He noticed that very large clearance between hole and collars can lead to fatigue failure of drill collar connections and that rotating with a bit off bottom can be worse than drilling with the full weight of drill collars on the bit in highly inclined holes when inclination decreases with depth in the dog-leg [8].

In previous references cited above, the equilibrium solutions are not applicable when buckling occurs or when the well paths are curved. The problems of drill collar instability in an inclined well and helical post-buckling equilibrium have been considered by Bogy and Palsay [9].

Reviewing the cited references and tens of others reveal that predicting the actual trajectory of a drilling bit is a very complex task. Many known and unknown variables interact and cause the bit to follow a certain trajectory. BHA configuration and dimensions, formation dip and lithology, bit size and type, hole curvature, degree of inclination, drilling parameters like WOB, RPM and GPM are some of the most important parameters that affect the inclination and Azimuth of the bit. Field experience is an important aspect of this technology.

Actual assemblies and drilling situations are too complex to rely on the simpler idealization that does not account for varying collar dimensions, material properties and multi-stabilizer arrangements. As a result, new technology is being developed using numerical solution methods and high-speed digital computers. Pioneering studies in this field, such as the work of Huang and Dareing [10] and Fischer [11] were mostly based on procedures such as the finite difference method which operates directly on the differential equations of bending of a structure model. As the first application of the finite element method in drilling mechanics, we can refer to the work undertaken initially by Nicholson [12] and later by Wolfson [13] at the University of Tulsa. Following their study, Millheim, Jordan and Ritter went on to apply a large, general-purpose, nonlinear finite element code for routine BHA analysis [14]. Millheim and Apostal were the first to implement complex three-dimensional dynamic models of a rotating BHA to study the effect of BHA on the trajectory of a bit [15]. Dunayevsky, Judzis and Mills applied analytical models of the entire drill string (not just BHA) to study the behavior of drill string in directional bore-holes and the dynamic stability of drill strings under fluctuating WOB [16,17].

In all BHA analysis algorithms proposed in previous references, it is assumed that the interaction between drilling bit and stabilizers and the formation can be described through simplified contact, torque and friction models imposed on the nodes of the finite element model. While this approach provides an overall analysis of the dynamic and static response of the BHA, it cannot consider the complex interaction between the teeth (or cutters) of the bit, the stabilizer blades and the formation. To overcome this restriction, Baird, Apostal and Wormley together with Caskey and Stone undertook the development of a three dimensional transient dynamic finite element computer program (GEODYN2) capable of simulating the behavior of a rotating BHA containing a PDC bit interacting with a non-uniform formation [18-20]. Brakel and Azar extend the same algorithm to accommodate roller cone as well as PDC bits [21].

All the models discussed before have the limitation of assuming of an initially straight centerline of un-deformed string, which precludes the use of bent tools (bent subs or bent housing motors) in the BHA. Brett et al. directly modified the computational method of Millheim and Apostal by using a series of coordinate transformations to achieve the desired result of a slope discontinuity in the centerline of the un-deformed BHA [22]. Williams and Apostal provided a more powerful software model to describe the steerable bottom-hole assembly analysis [23].

4. NUMERICAL ANALYSIS OF BHA BEHAVIOR IN WELL S-16

Here in this study, we have employed a well-known industrial drilling software in order to perform all computations and simulations of drilling string behavior. The WELLPLAN software from Landmark drilling software package (developed by Halliburton) is the main computation tool in this study. In the following section, we will simulate the behavior of the drill string in 8-1/2" hole-section and compare the simulation results with those we have observed in reality.

4.1. Analysis of BHA Tendency in 8-1/2" Hole-Section

The schematic of semi-pack BHA, which has been used in drilling of 8-1/2" hole, is shown in Fig. (**1**). Using the BHA tendency module of WELLPLAN software, the trajectory of the 8-1/2" hole was predicted considering the effect of BHA, drilling parameters and well deviation at the beginning of the hole (recorded at the end of the 12-1/4" hole-section). Comparisons of the predicted, actual and expected trajectories are depicted in Figs. (**2** and **3**). It should be noted that the actual well trajectory was the one measured using continuous gyro and CDR log as shown previously. The maximum depth we could take survey was 1845 meter and the actual well trajectory from 1845 meter to 2712 m was extrapolated using 2.27 °/100ft as build rate and -0.09 °/100ft as walk rate. These parameters selected as the trend we observed in well survey data before the depth of 1845 m. The expected well trajectory was drawn with the assumption of keeping well inclination and azimuth constant in 8-1/2" hole using a semi-pack BHA assembly which was indeed the main aim of using this BHA.

As it can be observed in Figs. (**2** and **3**), the BHA analysis can provide a general overview of the bit tendency and the probable well trajectory by considering smooth and constant drilling parameters in predefined intervals. The exact prediction of well trajectory based on drill string dynamic behavior is very difficult and even impossible because the BHA tendency calculations are strongly dependent on some parameters which are not completely known before drilling the formation. Formation hardness and anisotropy are of these unknown parameters that we should guess or approximate in our computations. Moreover, the drilling parameters we applied in our calculations including WOB, RPM and GPM are considered unchanged in every 300 meters intervals, but during drilling operation, this assumption is not completely true especially for WOB which varies according to formation hardness.

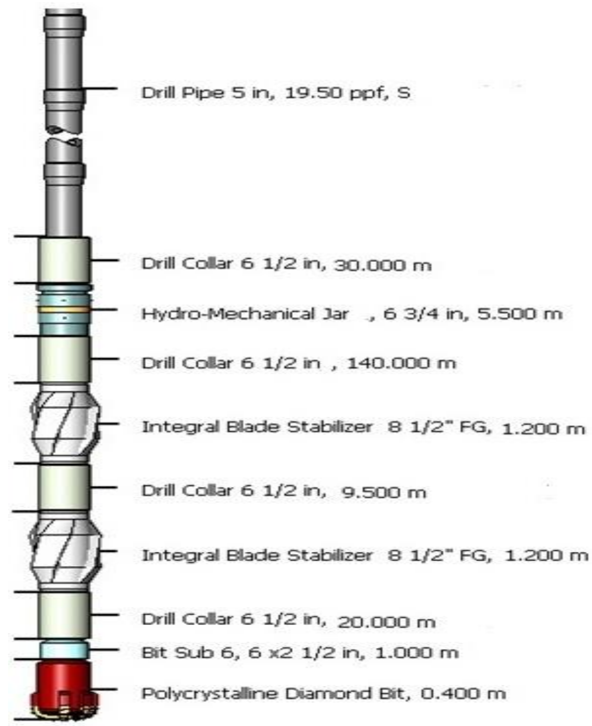

Figure 1: The semi-pack BHA Schematic for 8-1/2" hole-section.

Analyzing BHA tendency can relatively answer our first question. It can be concluded from available information that the main reason of well deviation, in this case, is the BHA affinity to build inclination. Of course other factors such as formation dip angle, heterogeneity in formation hardness and applying non-uniform drilling parameters have a great impact on well deviation. Omitting the effect of these factors may be the main reason of the difference between the actual well path and the predicted one. However, the present analysis reveals that despite our initial idea about the ability of selected BHA to prevent more well deviation, the designed semi-pack BHA has relatively large

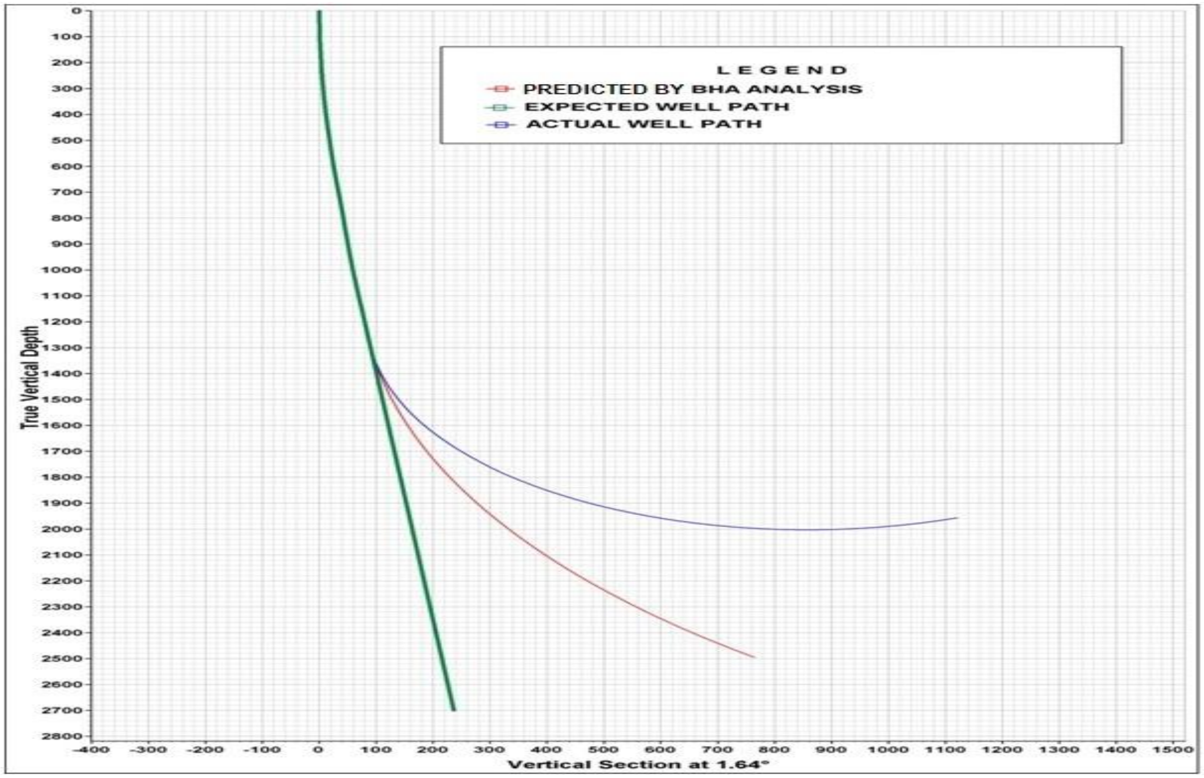

Figure 2: Comparison of vertical section of actual, expected, and predicted well trajectories.

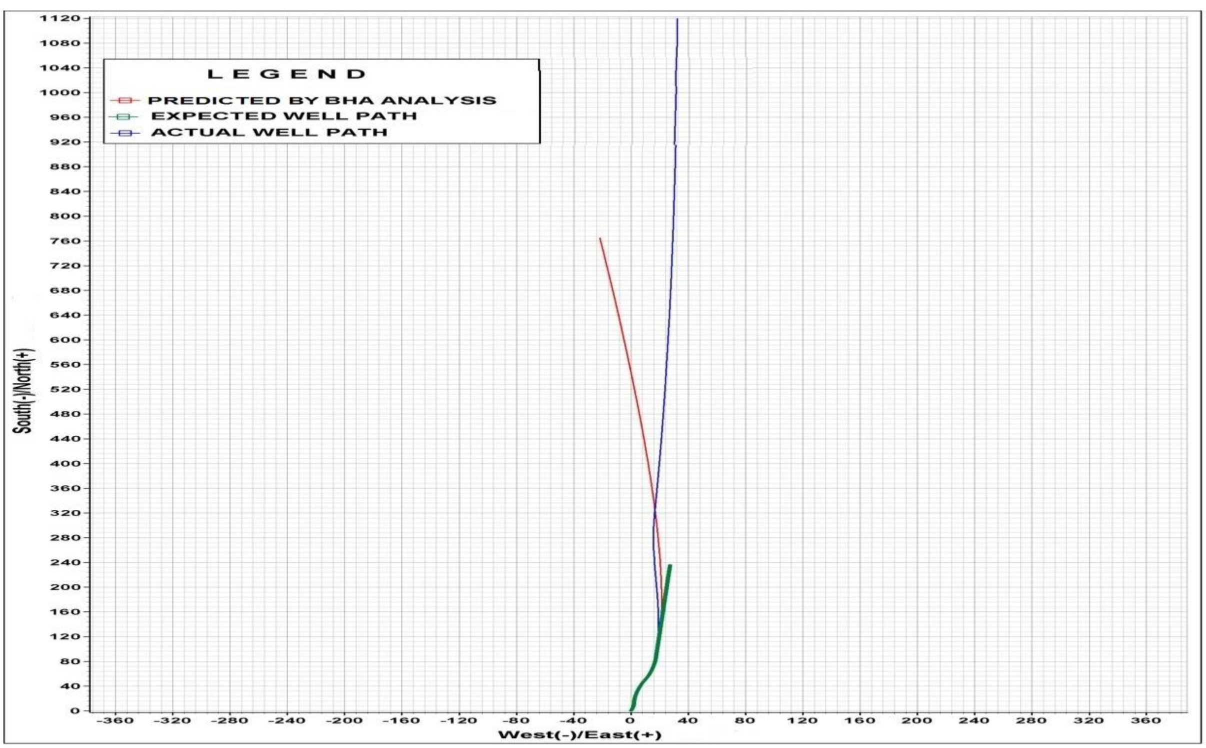

Figure 3: Comparison of horizontal plan of actual, expected, and predicted well trajectories.

potential to increase well inclination in this well. The build rate calculated by WELLPLAN is about 1 °/100ft while the actual measured build rate is variable between 1.2 to 1.8 °/100ft based on Gyro measurements. As a result, performing BHA dynamic tendency analysis prior to run the selected BHA could prevent such a failure in our drilling operation. Maybe a more accurate study of BHA dynamic behavior could lead to a suitable BHA with more stiffness to keep the well inclination below 5 degrees. In order to answer this question, we'll attempt to propose more suitable BHA to fit the conditions of our well at the beginning of 8-1/2" hole. Before that, in the next section, we are going to find the signs of such deviation which could warn earlier and alert us to execute remedial actions sooner.

4.2. Signs of Well Deviation in 8-1/2" Hole-Section

According to the results obtained in the previous section, the well deviation and a high build-up rate were predictable in the design section. During the operation phase, there were also signs of an unusual well situation that could help us to recognize the problem sooner and prevent wasting more time and money. Parameters that should be monitored more closely are the hook-load and drill string drags during drilling and condition trips. Therefore, torque and drag analysis were performed for the three well trajectories (Actual, Expected and Predicted by BHA analysis) and the results were compared with actual observed data gathered from well site. Results are depicted in Figs. (**4-6**).

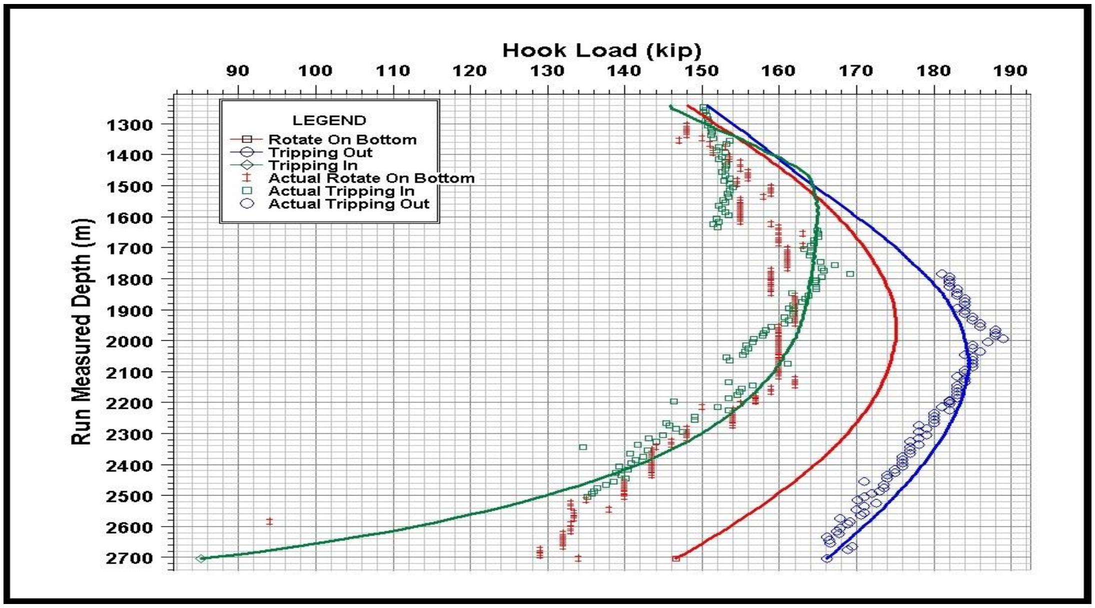

Figure 4: Hook-load simulation based on actual well path and comparison with observed data.

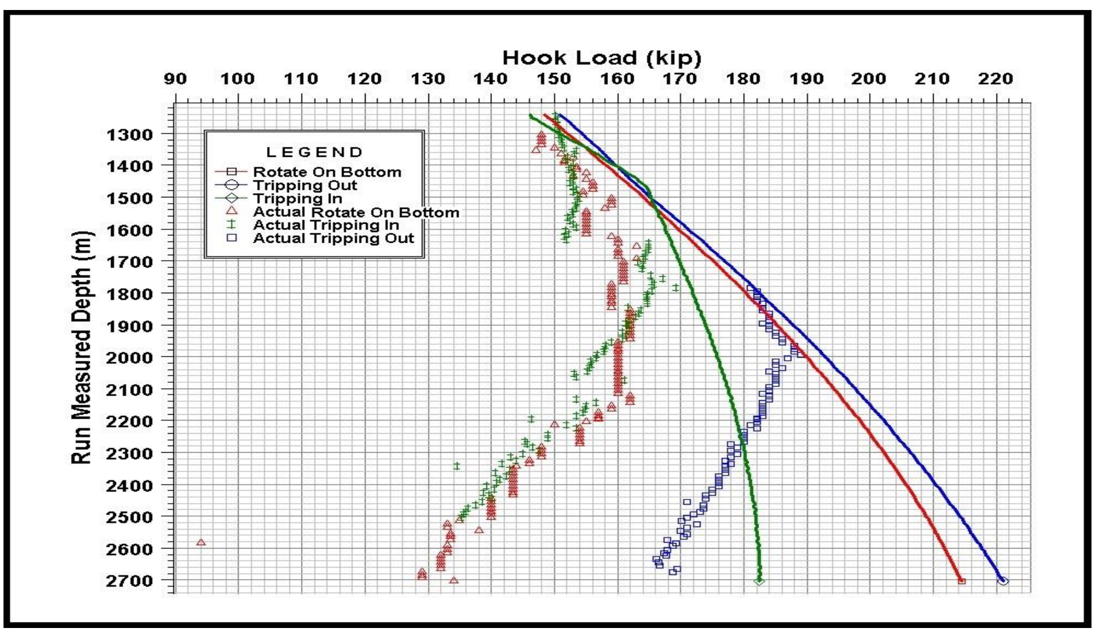

Figure 5: Hook-load simulation based on predicted well path (by BHA analysis) and comparison with observed data.

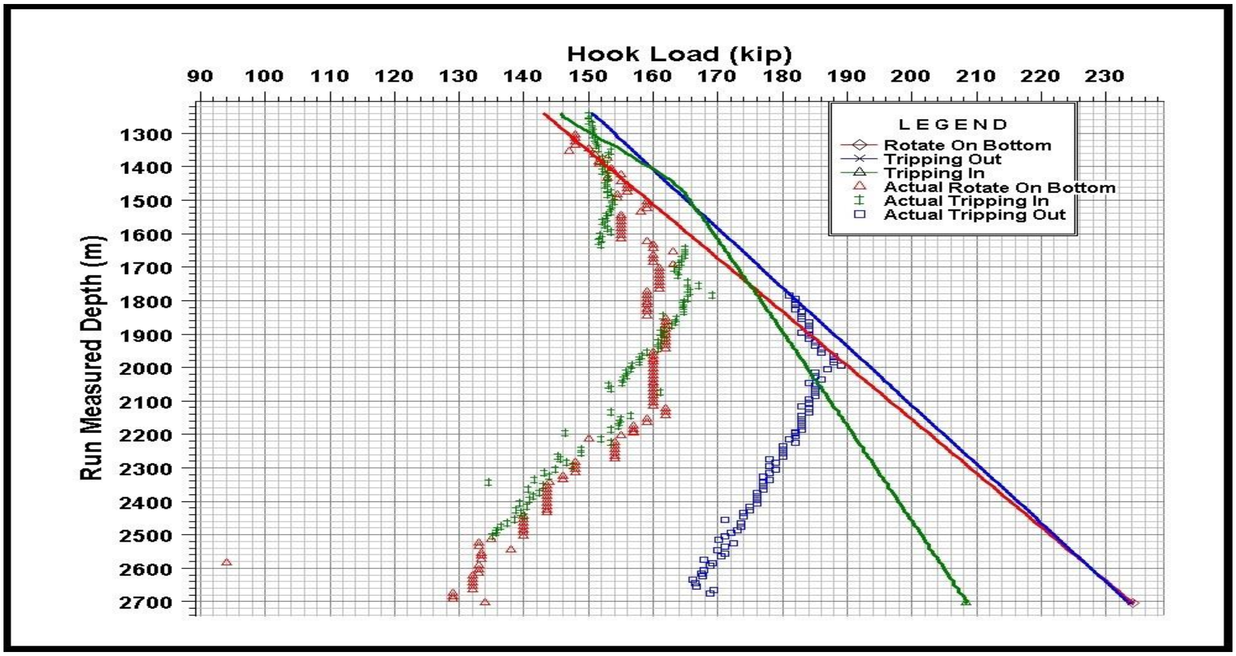

Figure 6: Hook-load simulation based on expected well path and comparison with observed data.

In order to perform hook-load simulation during drilling, tripping in and tripping out, the Torque & Drag module of WELLPLAN software has been employed. The simulated results are obtained considering some uncertain parameters including open-hole and cased-hole friction factors. These uncertain parameters are trying to be tuned based on actual data and simulation outputs of actual well path. The hook-load simulation on the actual well path and its compatibility with observed data has shown in Fig. (**4**) that confirms the validity of the actual well path and also the accuracy of drag analysis in this study. However, in actual practice, we assume that there is no accurate measurement of the well path and we just want to detect the drilling condition by observed drilling and tripping information. The unusual behavior in Hook load changes during drilling operation and tripping are clear in Figs. (**5** & **6**). In a normal well condition, the hook-load must raise by increasing depth, but in observed data of well S-16 an unusual trend was obvious after the depth of around 2000 m in which a continuous decline in hook load was observed during drilling and tripping (Figs. **5** & **6**). The anomaly in well condition and the effect of well trajectory in hook-load behavior, which is evident by comparing (Figs. **5** & **6**), could be considered as a sign of unexpected well path. Therefore, making simulation and tracking of observed data by comparing with simulation outputs could lead to earlier detection of a problem. Stopping the drilling in earlier stages of operation and making more accurate measurements could prevent wasting time and money. Even the plug back and side-track operation might be avoided if the well deviation had been detected sooner.

4.3. Drilling Plan to Avoid the Problem

In order to prevent the same problem in future operations, we have investigated some revisions in the current plan. These modifications are focused on changing stabilizer configurations in the BHA. In this part of the study, we have considered the current well drilling operation to the depth of 1260 meters (9-5/8" casing shoe @ 1253.5 meters) with the measured well trajectories and try to work on well geometry by changing the position of stabilizers in BHA for drilling the rest of 8-½" hole-section. In this examination, all the drilling parameters are kept constant and just BHA has been changed in various scenarios. The drilling parameters are shown in Table **3**. The results of this study which have been achieved based on simulations performed in Bottom Hole Assembly module of WELLPLAN software (Landmark Software) are summarized in Table **4**.

Table 3: Fixed Drilling Parameters Considered to Investigate the Effect of Stabilizers on Well Trajectory

WOB	25 Klbf	Bit coeff.	20
String Rotation	180 rpm	Formation hardness	35
Mud Flow rate	550 GPM	ROP	10 m/hr
Torque at bit	1000 ft-lbf	Drill-Ahead interval	300 m

Table 4: The Effect of Different BHA Configuration in Well Trajectory of 8 ½" Hole-Section

#	Stabilizer Position	Inclination				Direction				Build Rate (◦/100ft)	Walk Rate (◦/100ft)
		Wellbore (◦)	String (◦)	Tilt (◦)	Force (lbf)	Wellbore (◦)	String (◦)	Tilt (◦)	Force (lbf)		
1	Stab. #1 :@ 21 m, FG Stab. #2 :@ 32 m, 1/8" UG	14.74	14.80	0.05	-557	0.45	0.45	0.0	205	0.89	-0.31
2	Stab. #1 :@ 21 m, FG Stab. #2 :@ 32 m, FG	14.75	14.80	0.05	-554	0.09	0.09	0.0	205	0.90	-0.35
3	Stab. #1 :@ 21 m, 1/8" UG Stab. #2 :@ 32 m, FG	14.77	14.82	0.05	-545	359.3	359.3	0.0	202	0.90	-0.43
4	Stab. #1 :@ 21 m, 1/8" UG Stab. #2 :@ 32 m, 1/8" UG	14.77	14.82	0.05	-548	359.7	359.7	0.0	203	0.9	-0.39
5	No stabilizer	14.84	14.89	0.05	-551	358.3	358.3	0.0	180	0.9	-0.53
6	Stab. #1 :@ 11 m, FG Stab. #2 :@ 21 m, FG	10.42	10.45	0.03	-281	2.22	2.22	0.0	89	0.46	-0.13
7	Stab. #1 :@ 11 m, FG Stab. #2 :@ 21 m, 1/8" UG	10.06	10.08	0.03	-263	2.77	2.77	0.0	82	0.42	-0.08
8	Stab. #1 :@ 11 m, 1/8" UG Stab. #2 :@ 21 m, FG	11.73	11.77	0.04	-330	0.52	0.52	0.0	109	0.59	-0.30
9	Stab. #1 :@ 11 m, 1/8" UG Stab. #2 :@ 21 m, 1/8" UG	11.37	11.41	0.04	-313	0.94	0.94	0.0	102	0.55	-0.26
10	Stab. #1 :@ 31 m, FG	14.81	14.86	0.05	-545	356.4	356.4	0.0	190	0.9	-0.73
11	Stab. #1 :@ 21 m, FG	14.65	14.70	0.05	-593	4.34	4.34	0.0	203	0.89	0.08
12	Stab. #1 :@ 11 m, FG	5.42	5.42	0.0	-46	6.9	6.9	0.0	2	-0.05	0.34
13	Near Bit Stab, FG	13.99	14.01	0.03	785	347.72	347.72	0	-194	0.82	-1.60
14	Stab. #1 Near Bit, FG Stab. #2 :@ 11 m, FG	5.74	5.74	0	-65	6.98	6.98	0	8	-0.02	0.35
15	Stab. #1 Near Bit, FG Stab. #2 :@ 21 m, FG	15.13	15.16	0.03	988	352	352	0	-185	0.93	-1.11
16	Stab. #1 :@ 11 m, FG Stab. #2 :@ 31 m, FG	7.03	7.04	0.01	-117	3.81	3.81	0.0	34	0.11	0.03
17	Stab. #1 Near Bit, FG Stab. #2 :@ 11 m, FG Stab. #2 :@ 21 m, FG	10.57	19.59	0.03	-138	1.65	1.65	0	78	0.47	-0.19
18	Stab. #1 Near Bit, FG Stab. #2 :@ 11 m, FG	7.23	7.24	0.01	-124	1.98	1.98	0	42	0.13	-0.16

Information in Table **4** describes what is happening at the bit in the inclination and direction planes as well as build and walk rates. The inclination plane is the vertical plane. The direction plane is rotated 90 degrees to the vertical plane. A positive (+) value indicates the force is acting in an up or right direction while a negative (-) value indicates the force is acting in a down or left direction. The plane parameters are described as bellow:

- **Wellbore** – This angle indicates the inclination/ direction of the wellbore relative to the vertical/ direction plane.
- **String** – This angle indicates the inclination/ direction of the string or the bit face relative to the vertical/ direction plane.
- **Tilt** – This angle indicates the bit tilt which is the difference of Wellbore and String angles.
- **Force** – This indicates the magnitude of the force in the inclination/ direction plane acting perpendicular to the bit.

It is evident from Table **4** that actual BHA (case #1) has resulted in large values of build rate (0.89 ◦/100ft) and walk rate (-0.31 ◦/100ft) which are related to high side forces in inclination and direction planes respectively (-557 lbf and 205 lbf). Cases 12, 14, 16 and 18 have the least build rates compared to other scenarios, which is in agreement with the low side forces they have created in the inclination plane. The common thing among these successful scenarios is the placement of one stabilizer in 11 m above the bit. On the other hand, it is obvious from Table **4** that the BHAs with stabilizer at 21 m above the bit mostly created high side forces and subsequently large build-up rates. Also, it can be concluded that the application of an extra stabilizer on 31 m above the bit has no significant effect on well trajectories. It seems that using near bit stabilizer intensifies the effect of other stabilizers in the BHA. When we used near bit stabilizer with the other one at 11 m above the bit, the side force in the inclination plane and build rate decreased. Also, when near bit stabilizer joined with the one at 21 m, the side force and build rate both increased. The other conclusion from Table **4** is that the effect of under gauge stabilizers decreases by increasing its distance to the bit. Finally, it can be stated that the buckling point in the current BHA with 6-½" drill collars in 8-½" hole-section while applying 25 Klbs, is somewhere around 11 m above the bit and therefore using stabilizer in this position is very effective in controlling the well deviation.

Among the best selected BHAs (#12, 14, 16 and 18) we can omit case 18 because we are drilling in a sticky marl formation with a tight-hole problem and using 3 stabilizers in the BHA may cause excessive torque and drags during a drilling operation. It can also increase the risk of the stuck of drilling string. In order to propose the best BHA and the proper drilling parameters, we have investigated the behavior of 3 selected BHAs (12, 14 and 16) within a range of drilling parameters. According to the initial analysis, it was observed that mud flow rate and rate of string rotation (RPM) don't have any noticeable effect on well trajectories. Therefore, we have performed a sensitivity analysis by changing WOB on a specific range. The maximum weight on the bit is calculated in a way to put the neutral point below the drilling jar. The results are depicted in Figs. (**7**-**9**).

According to the results, which are depicted in Figs. (**7**-**9**), we can express some conclusions about the selected BHAs. First of all, it's obvious that increasing WOB has led to an initial increase and then a more stable decrease in the absolute value of the vertical side force. This behavior has caused a similar trend in well inclination (after 300 ft drilling ahead) and buildup rate. In fact, we can say that increasing WOB can decrease the side force, the inclination and the build rate of the selected BHAs in the desired interval of WOB. On the other hand, the trend is different in the direction plan. The graphs reveal that increasing WOB has decreased the side force in the direction plan, but the azimuth and walk rate has been increased. Finally, it can be stated that among these BHAs, the best inclination control can be achieved by BHA#12 while the azimuth control is easier by using BHA#16. Selecting each of these BHAs depends on the current well trajectory and the desired modifications we are willing to apply.

5. CONCLUSIONS

In this article, a case of failure in a gas well drilling project has been reported. According to the field

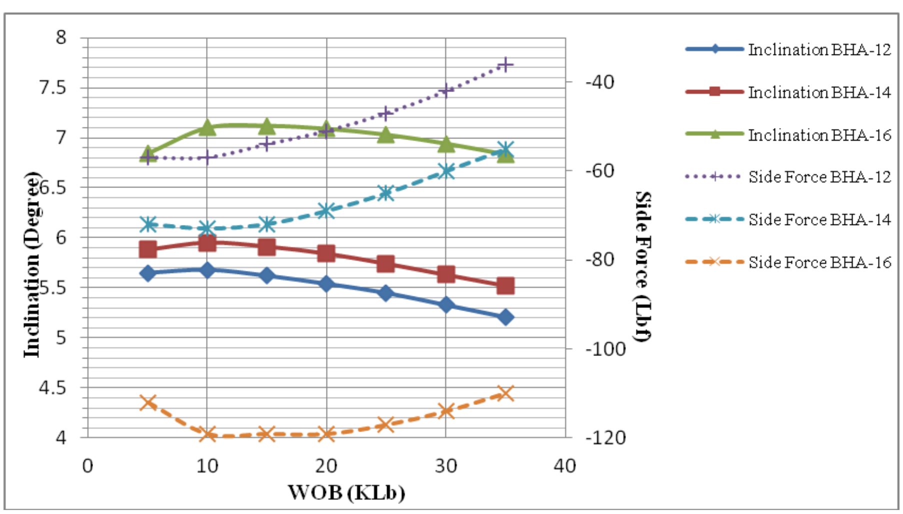

Figure 7: Inclination and vertical plan side force changes in different WOB for selected BHAs.

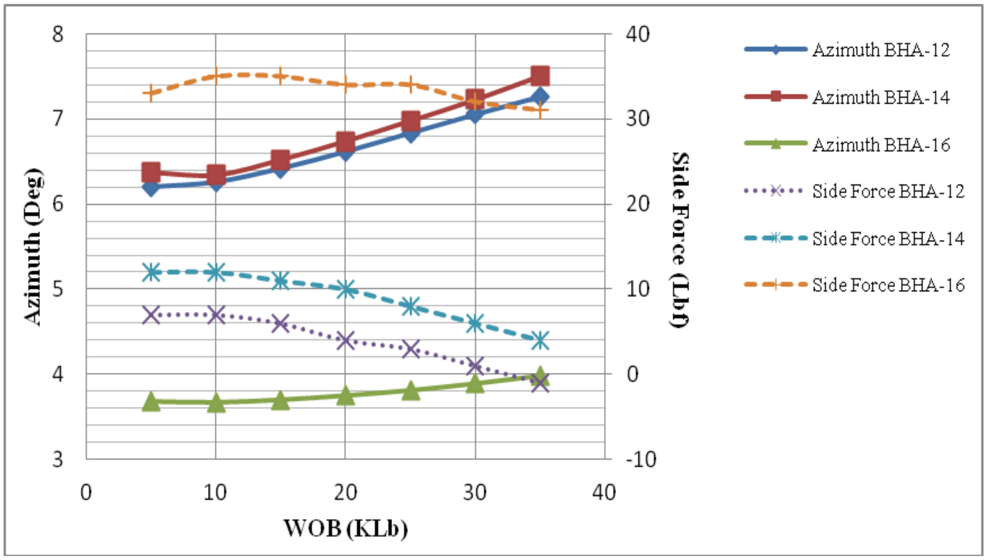

Figure 8: Azimuth and direction plan side force changes in different WOB for selected BHAs.

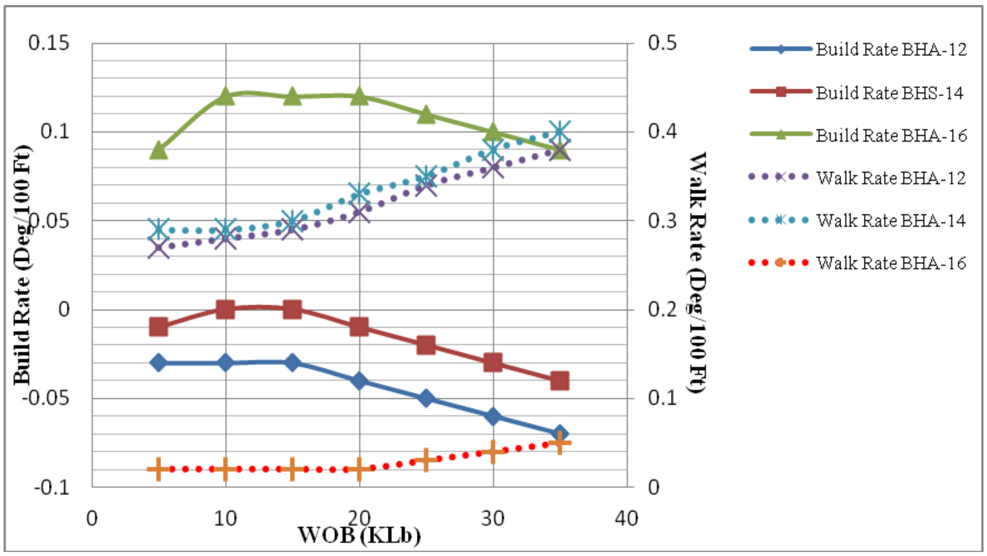

Figure 9: Build and walk rate changes in different WOB for selected BHAs.

investigations, it was revealed that an unexpected high well deviation was the main reason for the problem. As a result, the well was plugged back and a new hole was drilled using PDM and MWD tools. This failure led to about 20 days delay in operation and made thousands of dollars loss in this drilling project.

In order to study this case and take lessons from the problem, we have tried to simulate the drilling situation using drilling software and compared the results with those recorded from the actual operation. The main conclusions of these examinations are summarized as below:

1. Performing BHA analysis before applying any new BHA in a field can help the drilling engineers to make more reliable plans. As it is shown in this paper, the suggested semi-pack BHA in well S-16 has a strong tendency to build inclination which is the observed trend in both reality and simulations.

2. Analyzing various BHAs with different combination of stabilizers suggest that putting a stabilizer at 11 meters above the bit can be very effective in well deviation control. Also, sensitivity analysis showed that such BHAs can tolerate a large range of WOB without the risk of well deviation. It seems that using the recommended BHAs could prevent the unwanted inclination build-up rate. However, this can be confirmed only by application in the next field operations.

3. Monitoring mechanical parameters like hook load, torque and drag during drilling and trips can help us to have a better vision about what's happening in the hole. We observed in this study that simulating the torque and drag charts of the applied BHA and comparing it with the actual data could give us a good clue about the problem in the operation in the earlier stages of the operation. This could reduce the financial and operational costs.

4. In general, it can be expressed that using credible drilling simulation software both in the design and operations of a drilling project will be very helpful to design the best plan and also detect the anomalies. Expending some money for supplying the powerful software and training the engineers can prevent larger financial and technical losses.

5. It should be noticed that the simulation software which has been applied here has some weak points. For example, the formation dips are not involved in BHA tendency analysis. Moreover, the effects of bit structure and formation mechanical behaviors are just included by some uncertain parameters. Bit coefficient and formation hardness are two parameters that don't have a clear definition and a certain way to be calculated. The same thing is true about the torque and drag analysis parameters like torque at bit and friction factors. I believe that using advanced simulators that consider more effective and measurable parameters will help us reduce the uncertainty of predictions and plans.

NOMENCLATURES

BHA	=	Bottom Hole Assembly
GPM	=	Gallon per Minute (Unit of mud flow rate)
MWD	=	Measured While Drilling
pcf	=	pound per cubic foot (unit of mud density)
PDC	=	Polycrystalline diamond compact
PDM	=	Positive Displacement Motor
RPM	=	Round per Minute (unit of drilling string rotation speed)
WOB	=	Weight on Bit (Klb)
TVD	=	True Vertical Depth (meter)

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