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# DYNAMIC BHA ANALYSIS PROGRAM AND OPERATION ROAD MAP OPTIMIZES HOLE ENLARGEMENT WHILE DRILLNG PERFORMANCE, MARS BASIN - GoM

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**Abstract**
Hole enlargement while drilling (HEWD) is an important technique in both deepwater and onshore drilling. Drilling interbedded formations is a difficult HEWD application. Two extreme cases can occur. One case is when the reamer drills in soft formation while the bit is in a harder formation. The other more difficult situation is when the reamer is in a hard formation while the bit drills ahead in soft formation. The latter creates an enormous challenge for the reamer to drill the harder formation without inducing large lateral and torsional vibrations which is detrimental to the reamer and other BHA components. An overall HEWD operating parameter management approach can greatly reduce probabilities of tool damage and unnecessary tripping while dramatically reducing drilling costs.

A state-of-the-art BHA dynamic analysis program that allows modeling the reamer and bit in different formations plays a vital role in the overall HEWD management process. Before any planned HEWD operation, various possible operating scenarios can be virtually simulated through the BHA dynamic analysis program to evaluate the effect on BHA components of lateral and torsional vibrations. An optimized BHA configuration can be specified through these analyses and a set of optimal operating parameters for the chosen BHA can be developed.

This paper presents a case study of HEWD through severely depleted interbedded formations in the Gulf of Mexico. Previous offset wells had required multiple runs to HEWD this section due to reamer cutting structure damage. Models were constructed to compare performance with a range of BHA, WOB/WOR and RPM combinations. A set of optimal operating parameters and a road map were established for managing these parameters on the rig. Most importantly, the analyses recommended operating conditions that were substantially different from the accepted HEWD operation of increasing weight on bit (WOB) in harder formations. The analyses indicate that overall BHA performance was dramatically affected by weight on reamer (WOR). With a small sacrifice of ROP in the harder, more abrasive formations the HEWD system can effectively drill through the entire section without tripping due to component failure. This approach achieved excellent overall cost effective performance saving the operator $1.89 million on an offset well.

**Introduction**
The operator announced its field discovery in the Gulf of Mexico's Mars Basin in September, 2002. It is in 3,000ft of water, and is located approximately 88 miles southeast of Port Fourchon, Louisiana (Figure 1).

During recent field development, the operator experienced problems with a BHA component. Specifically, the reamer[1,2] was suffering cutting structure damage driving up field development costs and slowing time to production. This paper will present the application challenges and resulting tool issues in addition to the problem analysis and engineering design changes to the reamer and operating parameters intended to solve the problem(s). Finally, the authors will present the results of applying the new technologies and operating parameters on the WELL #3 and how they saved the operator $1.89 million compared to costs incurred drilling the offset WELL #2.

**Challenges**
While drilling the WELL #2, the operator discovered depleted formation pressures in the A sand. These sands were being produced from a nearby TLP resulting in an 8.1 ppg depletion of the formation A sand and a 6.2 ppg depletion of the B sand (for lithology profile, see Figure 2). The depletion caused serious problems drilling these two intervals on WELL #2, requiring three runs in the 13.5-in x 16.5-in interval due to failure of the concentric reamer when it encountered the A sand formations.

After a dedicated drill-out from the 13.375-in x 16-in expandable casing two 13.5-in PDC bits were used to drill the 13.5-in x 16-in interval on the WELL #2. The first PDC bit was a 6-bladed bit utilizing 16mm cutters. This bit was pulled after penetrating the A sand and showed no damage although the reamer cutters showed significant wear. A decision was made to run a 7-bladed PDC bit with 16mm cutters back in the hole to complete the interval reasoning that a heavier set bit might decrease vibrations due to the bit drilling somewhat slower. Surface and downhole sensors indicated moderate to severe lateral and torsional vibrations were occurring as the bit exited the sand resulting in stick/slip at the reamer. The reduction in depth of cut per revolution on the heavier set 7-bladed bit would result in slowing the bit ROP and reducing the reamer's depth of cut, thus reducing vibration intensity seen at the reamer. This bit did complete the interval and was pulled in excellent condition however, vibrations were still occurring until the reamer completely exited the A sand.

For the HEWD tool, two 13-in OD concentric reamers were required to enlarge 5,960 ft of hole section from 13.5-in to 16.5-in in depleted sand and shale, beginning at 13.375-in x 16-in, 54lbf expandable casing shoe at a bit depth of 10,390 ft and ending at a reamer depth of 16,350 ft. It needs to be emphasized that the concentric reamer was located 175 ft above the 13.5-in PDC bit with the rotary steerable tool and MWD/LWD telemetry tools below the concentric reamer as shown in Figure 3.

The first reamer tool was used to enlarge a 5,815 ft interval at an average ROP of 100 ft/hr in the shale formation and 40 ft/hr in the depleted A sands. The HEWD parameters were: 13.6 ppg mud weight, 100 rpm, 4-15 kft-lb torque, 10 klbs WOB, 950 gpm, and a pump pressure of 4,730 psi. The rotary steerable system (RSS)-based BHA was pulled out of the hole because the drilling assembly encountered high levels of torque (15 kft-lb) and near zero ROP while the reamer was in the lower depleted A sand at 16,205 ft. At the surface, engineers discovered the PDC bit was still in good condition but the concentric reamer had sustained severe cutter wear (Figure 4). The second reaming tool was tripped into the hole down to 16,130 ft and drilled/reamed the remaining 145 ft of formation without incident. The HEWD parameters were: 13.6 ppg mud weight, 90 rpm, 8 kft-lb torque, 15 klbs WOB, 800 gpm and a pump pressure of 4,540 psi. To optimize drilling in the depleted A sand section, the operator needed to find a solution to improve the HEWD performance.

Engineers conducted an in-depth dull grading study to determine the cause of the failure and eliminate the added expense of the trip time and new tool cost. Initial field evaluation of the reamers indicated that cutting structure failure was possibly associated with torsional and lateral vibrations. These type vibrations are common in HEWD applications and it can be magnified when drilling in depleted sands. It is interesting to note that all PDC bits were pulled in good condition after the initial reamer run and were used again after changing out the worn concentric reamer. The analysis also revealed that vibrations drilling the section prior to encountering the A sand were insignificant with the frequency, strength and duration increasing during while transitioning into the depleted sand section.

**Objectives**

Before spudding the next well (WELL #3), a team of operator and service-company engineers studied formation lithology of the previous well (WELL #2). Due to the close physical proximity, it was reasonable to assume the upcoming well WELL #3 would encounter a similar series of lithologies and formation profiles as drilled in the WELL #2 (Figure 2). However, based on the concentric reamer's cutter issues outlined above, there was a possibility it would require two reamers in the 13-1/2-in x 16-1/2-in BHA to complete the section adding significant cost to the well.

While planning WELL #3, it was determined one of the key engineering objectives would be to drill the problematic A sand with just one drilling assembly run. To achieve the objective, engineers evaluated the possibility of changing the OD size of the PDC pilot bit to eliminate the dedicated drill out of the 13.375-in x 16-in expandable casing. The reamer would have to be capable of enlarging the entire 6,185 ft of 13.9-in x 16-1/2-in hole section with depleted sand and shale, beginning at the 13.375-in x 16-in, 54 ppf expandable casing shoe. Good wellbore quality was another primary objective allowing the operator to run the 13.375-in casing string to the section bottom without issues.

**Bit Selection**

Based on a performance review of the WELL #2 in the key HEWD section, engineers outlined the following PDC bit challenges/requirements to ensure optimized bit/reamer interaction and to make sure the section would be completed in one BHA run:

- Compliment the concentric reamer & BHA
- Minimize vibrations
- Drill the section shoe to shoe
- Balance bit and reamer cutting structure performance
- Eliminate a dedicated drill-out

Due to tight time constraints, the bit supplier relied on two existing PDC designs to use as baseline models to run in the service companies' integrated dynamic engineering analysis system (IDEAS) simulation software program.[3,4,5] IDEAS is a comprehensive time-based 4-D modeling tool that accurately predicts a drilling system's performance and behavior using finite element analysis, laboratory-derived drilling mechanics data and physical input data that accurately characterizes the attributes of the total drilling system. This bit and BHA dynamic modeling program will be discussed in more detail later in this paper.

The two bits used in the simulations were a 14-in, nine-bladed, 16mm cutter Mi916 and a 13-1/2-in eight-bladed, 13mm cutter MDi813. The 14-in Mi916 bit has been validated using the dynamic modeling program in the Gulf of Mexico with and without reamers. These existing designs were used in the simulations to reduce development time and meet the operator's tight deadline schedule.

During the simulations, engineers investigated the interaction between the reamer and proposed PDC bits. Figure 5 shows a static picture of the dynamic simulation of bit/reamer patterns while drilling in shale below the sand at the recommended maximum weight-on-bit (WOB) when transitioning the sand. Because the two simulations were virtually identical, engineers decided it would be more efficient to down-size the 14-in bit rather than build-up the 13-1/2-in bit to meet the 13.9-in requirement.

The final bit design incorporated many of the innovative features of the 14-in Mi916. It was run in the simulation software program and led to an in-depth understanding of the complex interdisciplinary downhole dynamics critical to increasing PDC drilling efficiency. Based on these tests, engineers determined the new-style bit, along with the optimized operating parameters would meet operator requirements and effectively minimize vibrations while improving borehole quality.

**Reamer Selection**

The cutting structure used on WELL #2 was a first generation concentric reamer design (Design 1). It had three identical blocks each containing two blades with 13mm PDC cutters and a large stabilizer pad with flat top tungsten carbide inserts near the center of the block (Figure 6). This cutting structure was designed to be very passive based on the design theory, that an aggressive cutting structure could induce excessive torsional instability. This design became a direct candidate for WELL #3 because of its known performance.

Another good candidate for the concentric reamer for WELL #3 was a new-style reamer containing the second-generation cutting structure (Design 2) which had been developed and introduced in late 2006. Design engineers made several significant changes including the removal of the stabilizer pad. This feature was replaced with pre-flat PDC gauge cutters and a flow channel between the blades on the block. The new design retained the 13mm PDC cutters. The advantages of this design are faster cut-out to full opening diameter and better hydraulic cleaning and cooling (Figure 6). This cutting structure was also passive and was designed prior to the implementation of the IDEAS dynamics modeling program as a reamer cutting structure design tool. Subsequent modeling has shown significant performance improvements can be achieved through cutting structure design.

**Dynamic Modeling Program**

The service provider's dynamic modeling program was used extensively in the BHA selection and parameter optimization process for WELL #3 13.9-in x 16.5-in HEWD section. This dynamic modeling program utilizes a general finite element analysis (FEA) approach plus a time variable to simulate bit and reamer cutting forces and vibration behavior with a specified BHA configuration, in a targeted formation profile, and under a set of selected operating parameters. It strongly relies on the BHA geometric configuration inputs, such as BHA component position and dimensions. It comprehensively considers the cutting tool and formation interaction in terms of cutting forces, dynamic loading, vibrations, and contacts with the wellbore wall.

The fundamentals of the rock cutting mechanisms with PDC cutters have been carefully tested in a laboratory environment and built into the analysis code of the modeling program to help predict the cutting tool behavior. The output of the analysis includes dynamic weight load distribution at bit and reamer, cutting tool lateral vibrations, torsional response of bit and reamer, cutting induced imbalance force at the tool and rate of penetration (ROP). These parameters reflect the entire BHA and individual cutting tool behavior during HEWD process.

The software is also capable of modeling a layered formation structure, including the situations when the bit is in a soft formation and the reamer is in a hard formation, and when the bit is in a hard formation and the reamer is in a soft formation. This gives the modeling program the capability to match and simulate the field operation conditions.

The purpose of using the dynamic modeling program was to evaluate the above proposed cutting tools and BHA, simulate the BHA component's downhole behavior, and recommend the best tool combination and operation parameter set in order to prevent similar technical difficulties that were experienced in the offset well, WELL #2.

The BHA dynamic analysis program can analyze different bit and reamer combinations in BHA and use different operational load parameters; most importantly it can virtually predict performance if a BHA component position or its configuration has changed. The simulations demonstrate various downhole scenarios showing the performance of the system component by component, especially the cutting tool lateral and torsional vibration conditions which greatly affect the tool's cutting effectiveness.

The BHA, cutting structure, and operation parameter selection process is a well established system which includes a selection flow chart and an emphasis on specific goals for the resultant system output parameters (Figure 7). The systematic selection begins with a performance objective, several candidate BHA's, and an available cutting tool portfolio. Through a standard comparison of particular traits, in this case reamer lateral and torsional vibration, the selection process systematically identifies the best BHA and cutting tool combination for the job.

**Operational Parameter Optimization**

The operator had determined the goal for WELL #3 was to complete the 13.9-in x 16.5-in HEWD section to target depth (TD) in a single run. Based on this objective, three different BHA's (Figure 8) were proposed as potential BHA candidates with different bit and concentric reamer combinations for the operation. The dynamic modeling program identifies the best BHA, the best cutting tool combination and the best of class operation parameters for achieving the objective.

The top priority was to mitigate both lateral and torsional vibration through BHA design and parameter management in order to minimize damage of the cutting structures and downhole tools in the BHA. To accurately predict the worst case scenario in the 13.9-in x 16.5-in section, the simulations were run at 16,300 ft MD, inclination of 25.33° and azimuth 300.20. At this depth, the formation at the reamer was the depleted sandstone with unconfined compressive strength (UCS) of 7,500 psi, and the formation at the bit was soft shale with UCS of 1,500 psi. Two bits and two concentric reamer cutting structures were compared at this depth using the offset BHA (BHA#1) to determine which bit and reamer combination would yield the lowest lateral and torsional vibration at the reamer.

The four simulations (2 bits x 2 reamers) were run at a WOB of 15 klbf, and surface RPM of 95, which were comparable to parameters used while drilling the similar section from the offset well, WELL #2. All other BHA components and parameters, except for the bit and reamer, were kept constant to ensure a direct comparison between the outputs of the simulations. Upon completion of these four simulations, the bit and reamer combination that yielded the lowest lateral and torsional vibration at the reamer was chosen for use in the 13.9-in x 16.5-in hole section. See Figure 9 for the results.

Further investigation of other BHA's was undertaken to determine the effect of BHA design on vibration at the reamer cutting structure. The results from the original offset BHA (BHA #1) and the two best BHA configurations were presented to the operator (Figure 8). BHA #2 was comparable to the BHA#1 except for a different reamer cutting structure - Concentric Reamer Design 2. BHA #3, with Concentric Reamer Design 2, was similar to BHA#1 but added a 15 foot pony drill collar and a pass-thru stabilizer above the concentric reamer.

The results showed that BHA #2 had a 49.2% reduction in average reamer lateral vibration compared to BHA #1, and BHA #3 had a 51.1% reduction in average reamer lateral vibration compared to BHA #1. BHA #2 also showed a 20.3% improvement in reamer torque over BHA #1. BHA #3 showed a 23.5% improvement in reamer torque over BHA #1.

To further decrease vibration levels, various WOB and RPM parameters were examined using BHA #2 and BHA #3. WELL #2 logs indicated when the bit and reamer each entered the depleted sands ROP slowed, WOB was increased to improve ROP. This most likely caused the severe damage to the reamer cutting structure, resulting in the added cost of an extra trip.

Simulations were run with BHA #2 and BHA #3 to compare WOB of 15 klbf and 8 klbf. Maintaining constant BHA, well profile, formations, and all other variables constant except for WOB, the simulations showed that decreasing the WOB dramatically decreases overall lateral and torsional vibration at the reamer. For BHA #2 and BHA #3, decreasing the WOB from 15 klbf to 8 klbf decreases the average reamer lateral vibration by 51.3% and 50.3% respectively. Torque at the reamer decreases 53.7% and 54.4% for BHA #2 and BHA #3 respectively (Figure 10). In addition, the maximum values of lateral vibration decrease by over 50% for both BHA's, and maximum values of torque at the reamer decrease by over 50%. The decrease in maximum torque values results in much lower values of delta torque at the reamer, which accounts for a decrease in overall stick slip at the reamer.

While decreasing WOB dramatically decreases the levels of lateral and torsional vibration at the reamer, it also decreases the overall ROP of the system. The BHA dynamic simulations indicated that for BHA #2, decreasing WOB from 15 klbf to 8 klbf decreases ROP by 41.5%. Changing WOB from 15 klbf to 8 klbf for BHA #3 decreases average instantaneous ROP by 47.1% (Figure 11). Although this does represent a significant decrease in ROP, this change WOB was only necessary while drilling and enlarging the depleted sand which is only 211 ft or 3% of the 6,158 ft HEWD section.

The BHA dynamic simulations were also done to examine the effect of changing rotary speed as a vibration mitigation technique. RPM of 70, 95, and 130 were simulated to determine the effect on lateral and torsional vibration at the reamer. Decreasing RPM from 95 to 70 decreased reamer lateral vibration by 5%, and increased reamer torsional vibration by 1.3%. Decreasing RPM from 95 to 70 also decreased ROP by 13.8%. Increasing RPM to 130 increased both lateral and torsional vibration at the reamer by 25% and 1.4% respectively while only increasing ROP by 2.3%.Therefore, varying RPM was not considered an effective vibration mitigation technique.

The overall recommendation resulting from the dynamic modeling program was to run BHA #3, with 8 klbf WOB and 95 RPM, which decreased both lateral and torsional vibration at the reamer and also increased ROP by 21.5% over BHA #1.

**Well Performance - WELL #3**

To ensure good communication with all personnel involved during the planning stages of the WELL #3, a "Road Map" was developed for HEWD operations with all the recommended bit and reamer selection and operating parameters. The purpose was to convey to the rig crew and operating personnel the importance of managing parameters by stating the objective of the run, the effects of parameter management and detailed instructions and graphics to explain the parameter management process through the depleted sands (Figure 12). Since exact parameters are difficult to maintain, a range of acceptable parameters was given.

In the WELL #3 BHA the concentric reamer was located 117 ft above the 13.9-in PDC bit with a rotary steerable tool and MWD/LWD telemetry tools in between (Figure 8). A 15 ft pony collar and 13-3/4-in integral pass-thru stabilizer were added above the concentric reamer to add lateral support. The new 13.9-in hole was drilled to 10,453 ft, which placed the concentric reamer 5 ft below the casing shoe. A ball was dropped to activate the concentric reamer. The tool was then pulled against the casing shoe verifying cutter block activation.

The HEWD rotation time was 114 hours. The reamer final depth was at 16,525 ft and reamer drilled interval was 6,158 ft. The average ROP for HEWD was 110 ft/hr in shale and 5 ft/hr in the depleted A sands. The WELL #3 was drilled and enlarged shoe-to-shoe in one run. The

HEWD parameters in the shale formations were: 13.6 ppg mud weight, 120 rpm, 12 kft-lb torque, 12 klbs WOB, 1,000 GPM, and a pump pressure of 4,700 psi. The WOB was then reduced to approximately 5 klbs in the sands as directed by the Road Map.

The visual inspection revealed that the reamer PDC cutting structure sustained only minor wear (Figure 13), with only two PDC cutters lost on the lower reaming cutting structure. No cutters were chipped or worn during the run. The PDC pre-flats on the cutter blocks and the backreaming cutters were in excellent condition.

**Discussion**

Using the dynamic modeling program in the BHA selection and well operation planning has shown many benefits. Through modeling various BHA scenarios and cutting tool combinations, operator and service company engineers have determined that cutting structure selection in a BHA is critical to a successful HEWD operation. The analysis also shows that operation parameter management is as important as selecting a proper cutting structure. The study results indicate that reducing WOB from 15 klbf to 8 klbf in the BHA decreased both lateral and torsional vibration at the reamer by over 50%.

It is interesting to note the impact of changing BHA components to mitigate the lateral and torsional vibration at the reamer had minimal effect compared to cutting structure selection and operation parameter management when drilling in the difficult formation. Only a small percentage of improvement was observed between BHA#2 and BHA#3.

The study results show that decreasing WOB while the reamer drilled through the depleted sands would temporarily reduce ROP performance in HEWD. However this change made it possible to preserve the reamer cutting structure and saved an extra trip to achieve the operator goal of completing the 13.9-in x 16.5-in HEWD well section to total target depth in a single run. This valuable lesson will be archived for reference when drilling future wells in the area.

From a cost standpoint, although the average ROP for WELL #2 was 78.8 ft/hr compared to the average ROP of 56.2 ft/hr for WELL #3, the overall objective of successfully drilling shoe-to-shoe in one run for WELL #3 was met. Figure 14 presents an ROP comparison for the two operations. WELL #3 was actually drilled in 2.2 fewer days than WELL #2 because the section was drilled without the extra trip to change out the damaged reamer cutting structure. This improved performance resulted in a cost savings of $1.89 million (Figure 15).

After the WELL #3 run, the operator collected the real-time downhole vibration data and distributed it to the service company engineers to perform a post-run analysis to verify the modeling prediction. Figure 16 presents the lateral vibration data from two independent sources, one is the direct measured LAS data and the other is the model simulation at a designated depth of 16,300 ft. The charts document that model predicted vibration magnitude closely matches the real-time vibration data record, validating the modeling program's capability to optimize the performance of the entire drilling system and to maintain dynamic stability without the excessive cost, time delays and risk of the traditional trial and error approach. Optimized operating parameters can increase tool life while helping mitigate vibration and its adverse effects on costly downhole electronic components.

**Conclusions**

The results of this project were very successful. Using the dynamic modeling program, the service provider was able to predict the drilling system's behavior in the problematic sections of the well. The well sections that are particularly difficult occurred when the bit is in a relatively softer (faster ROP) formation while the reamer is in a harder (slower ROP) formation. It was determined that drilling parameters, particularly WOB/WOR play a significant role in the stability of the bottom hole assembly. By studying the output of the model we were able to develop an operational road map to aid well-site personnel in properly managing drilling parameters. The goal of hole enlarging while drilling the entire 6,185 ft interval from shoe-to-shoe in a single run with acceptable rates of penetration was achieved. The dull condition of the concentric reamer cutting structure was very good and the hole was full gauge.

Subsequent studies have shown that by modifying the concentric reamer's cutting structures and managing operating parameters, even greater improvements can be realized. When we modeled this application with third generation cutting structures which are significantly more aggressive than the previous designs, we see substantial improvements in the dynamic stability of the system. The model shows that in this application we see a 70% improvement in the lateral and torsional stability of the system and significant improvements in ROP.

The dynamic modeling program has proven to be extremely valuable in developing concentric reamer cutting structures and drilling parameters for HEWD applications. We expect to see continued improvements in drilling tools, BHA design and run parameters using this modeling program.

**Acknowledgments**

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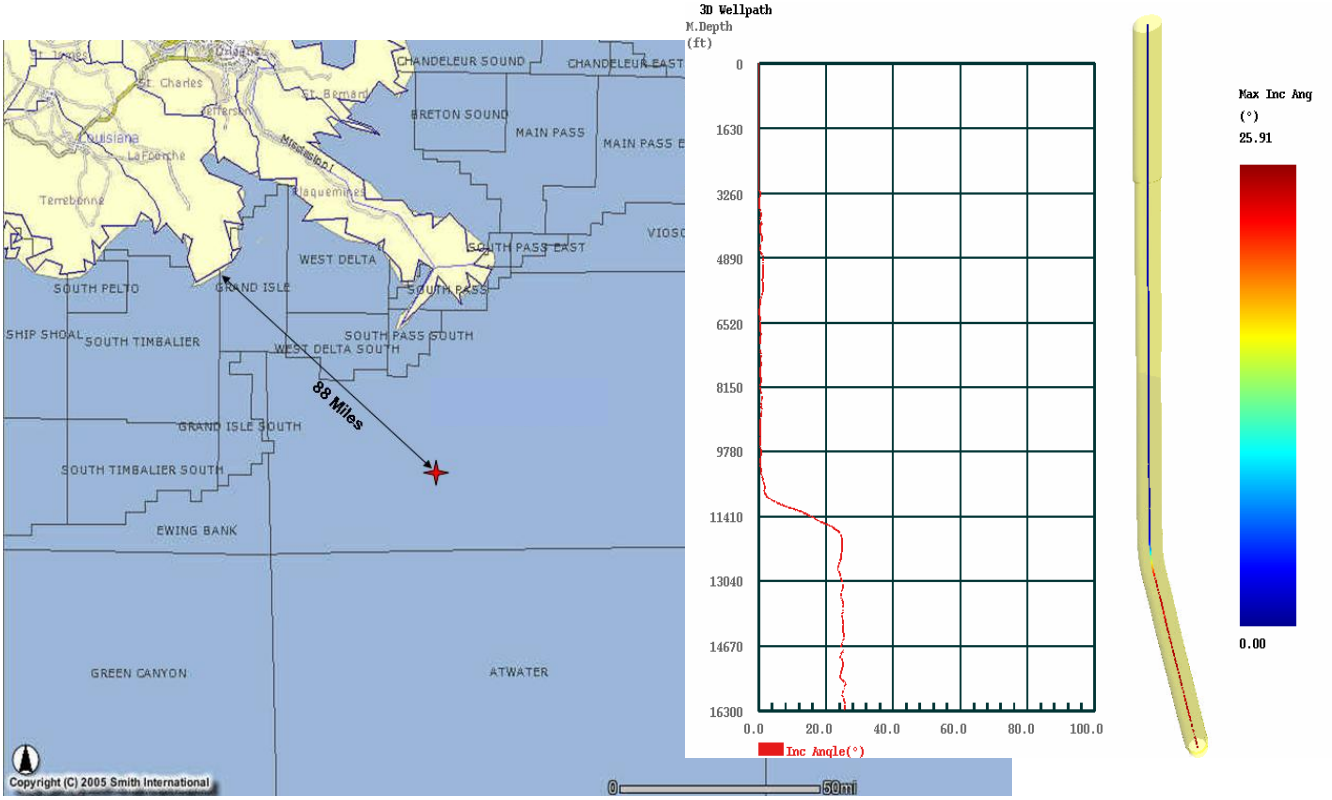



Figure 1- Well location and profile.

| | WELL#2 | | | | | | WELL#3 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Top | | Base | | Thickness | | Top | | Base | | Thickness | |
| Depleted Sands | MD | TVDSS | MD | TVDSS | MD | TVD | MD | TVDSS | MD | TVDSS | MD | TVD |
| Upper A-1 Sand | 15941 | 15436 | 16010 | 15498 | 69 | 62 | 15899 | 15470 | 15957 | 15523 | 58 | 53 |
| Lower A-2 Sand | 16066 | 15549 | 16132 | 15609 | 66 | 60 | 16024 | 15584 | 16097 | 15652 | 73 | 68 |
| Lower A-3 Sand | 16162 | 15636 | 16236 | 15703 | 74 | 67 | 16134 | 15686 | 16214 | 15760 | 80 | 74 |

Figure 2 - Well formation lithology profile.

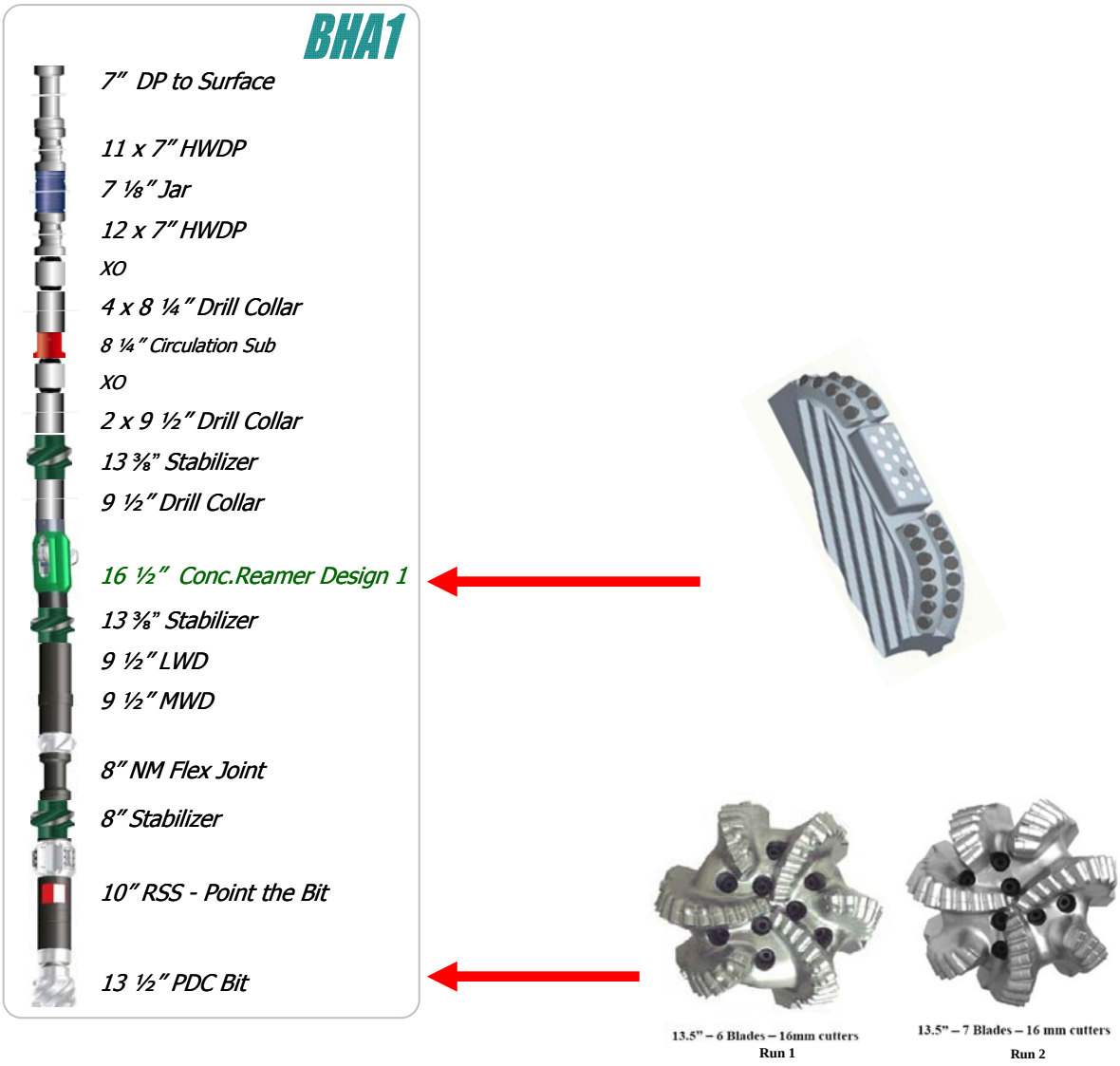
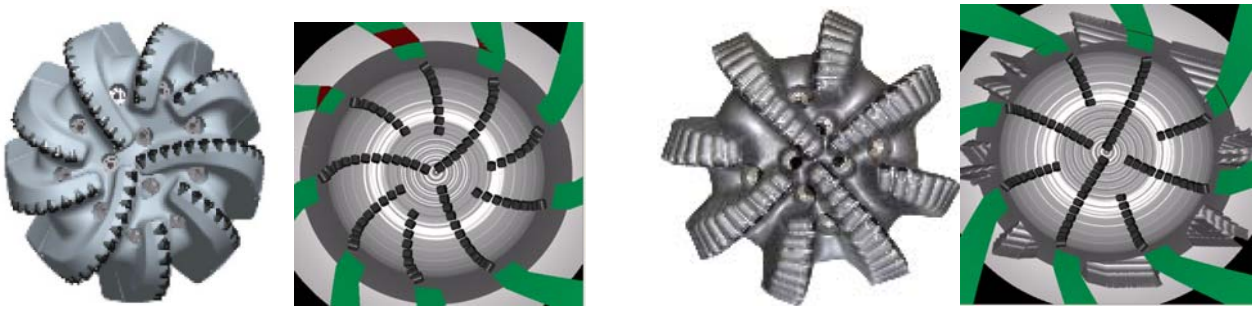



Figure 3 - WELL #2 BHA

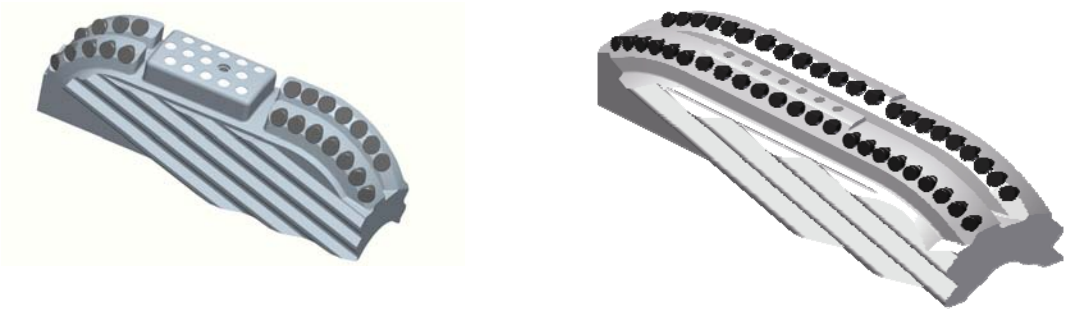
Figure 4 – Dull photos of 7-bladed PDC bit and damaged reamer from WELL #2. Note the reamer's lower cutter block is substantial worn away and is missing 11 of its 14 original PDC cutters.



14-in, 9-blade bit with 16mm cutters

13-1/2-in, 8-blade bit with 13mm cutters

Figure 5 - Two standard bit designs and simulated reamer runs documented it would be more efficient to downsize the 14-in design to 13.9-in to meet application requirements.



Concentric Reamer Design 1

Concentric Reamer Design 2

Figure 6 - Two proposed concentric reamer designs

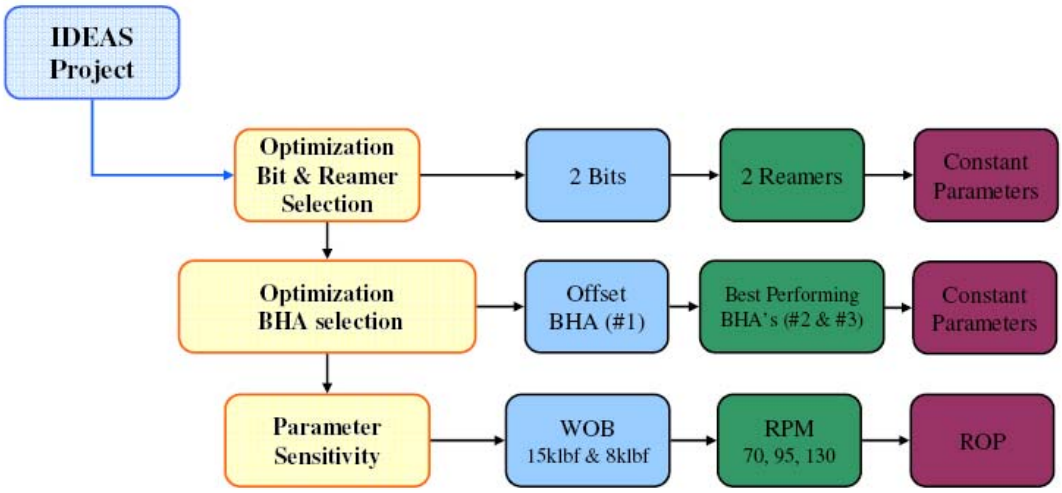



Figure 7 - IDEAS analysis flow chart

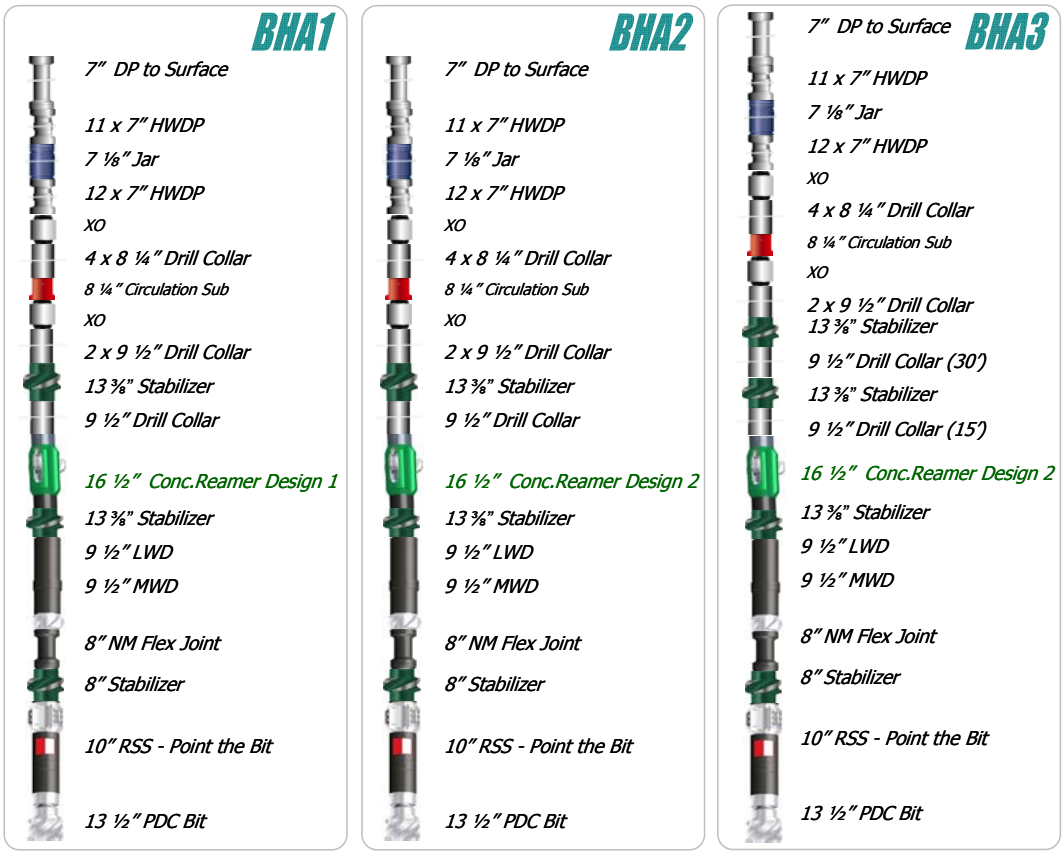



Figure 8 - Dynamic models for WELL #3

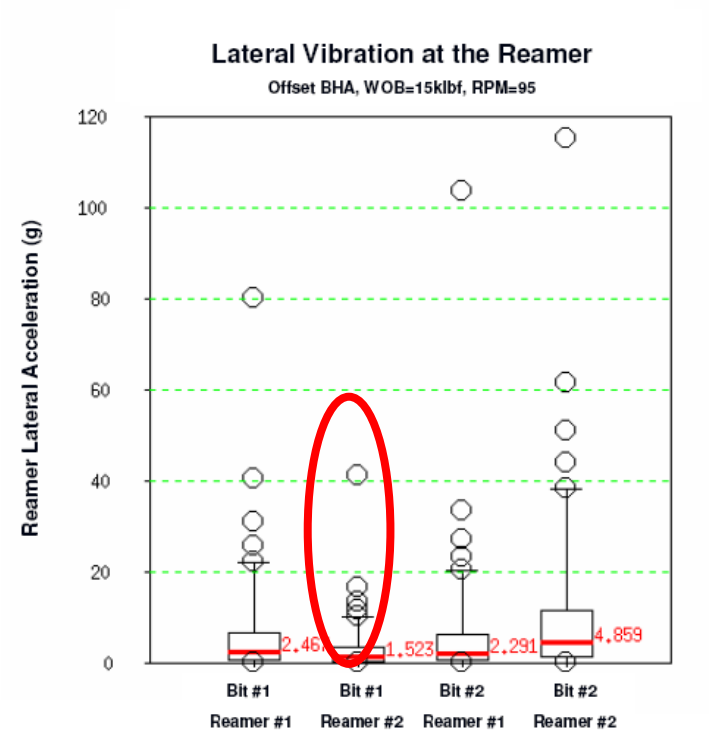



Figure 9 - Lateral vibration analysis result for BHA#1 with different bits and reamer designs

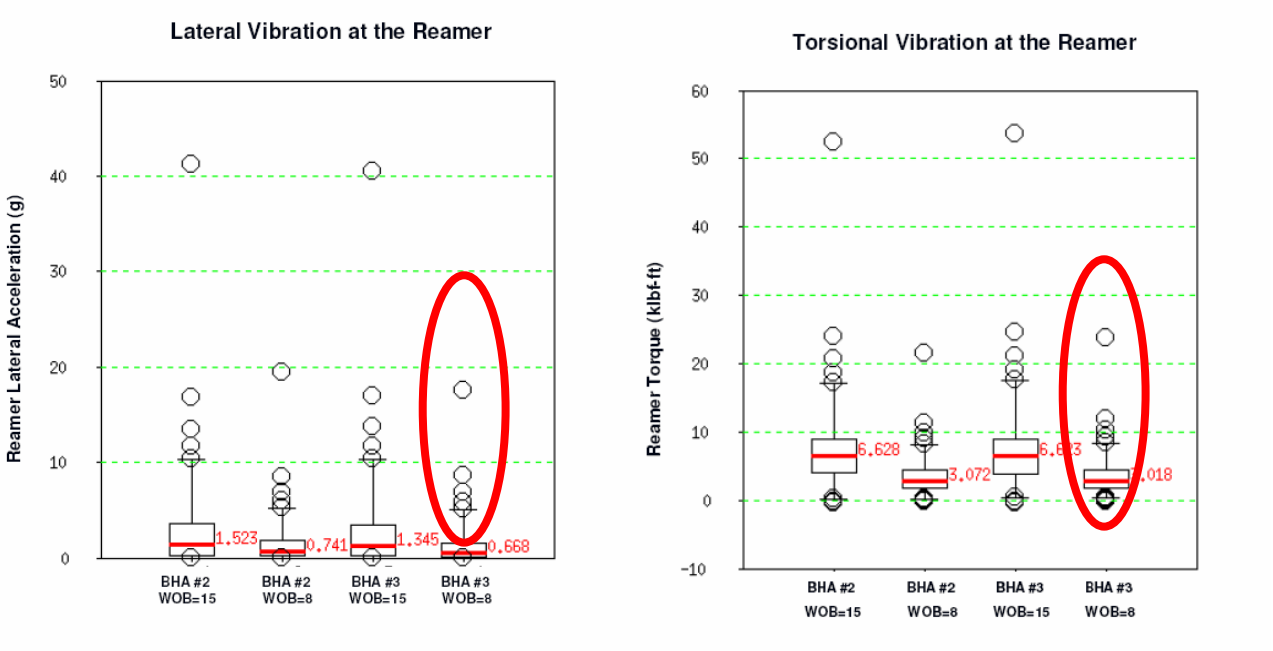
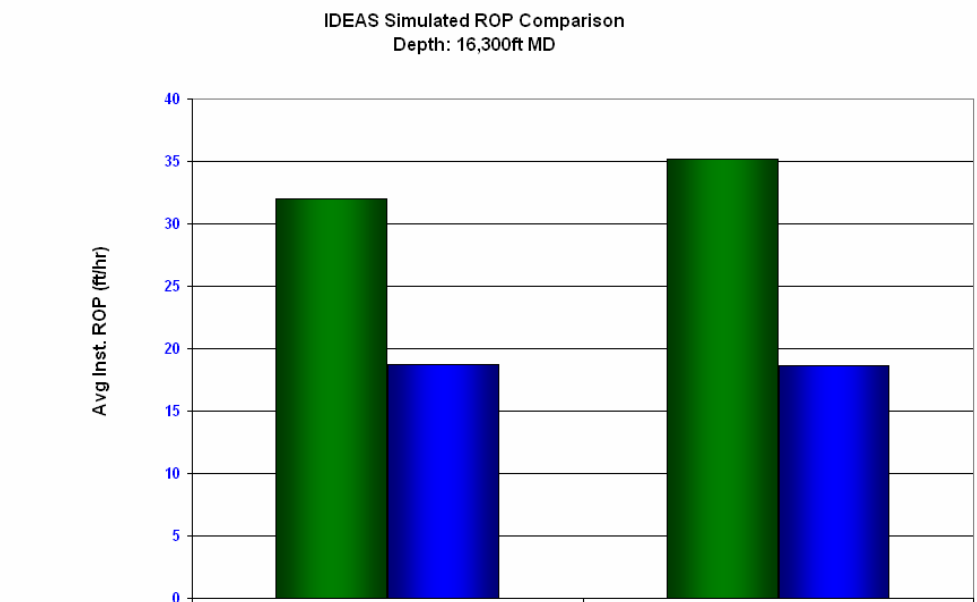



Figure 10 - Vibration analysis results for concentric reamer design 2 with bit #1 and different BHA's and WOB loads




| | BHA_2 | BHA_3 |
|---|---|---|
| Avg ROP (WOB=15klbf) | 31.96 | 35.148 |
| Avg ROP (WOB=8klbf) | 18.69 | 18.61 |

Figure 11 - ROP analysis results for bit #1 and different BHA's and WOB loads

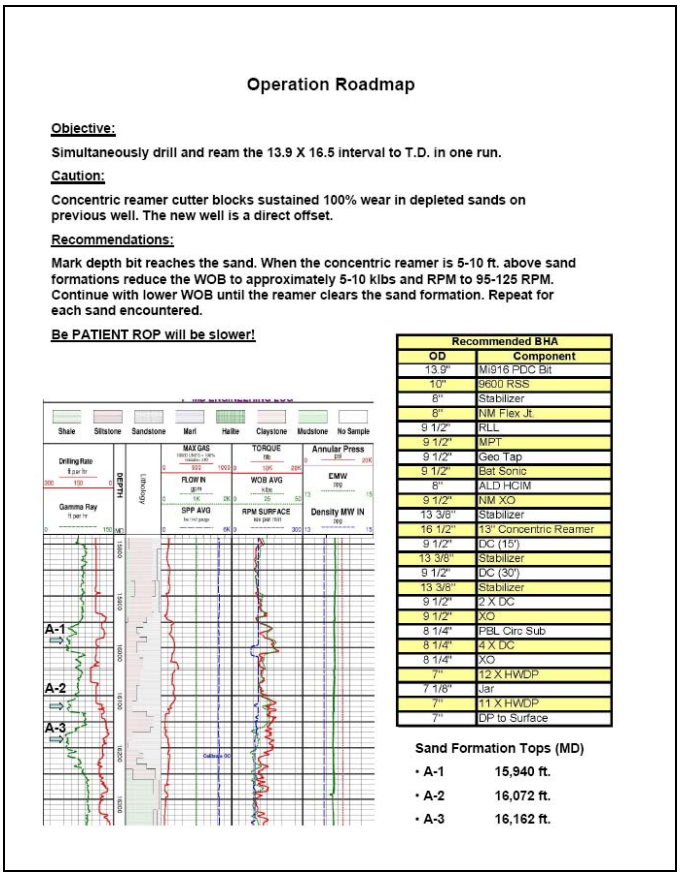
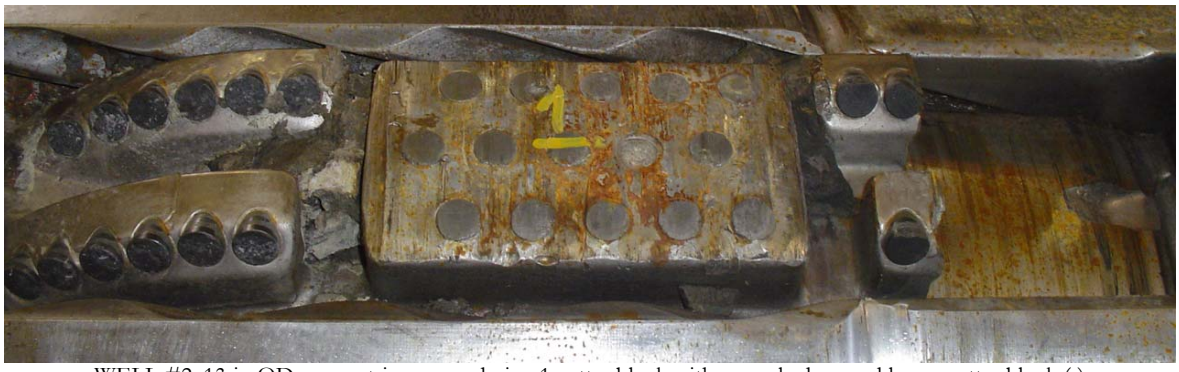
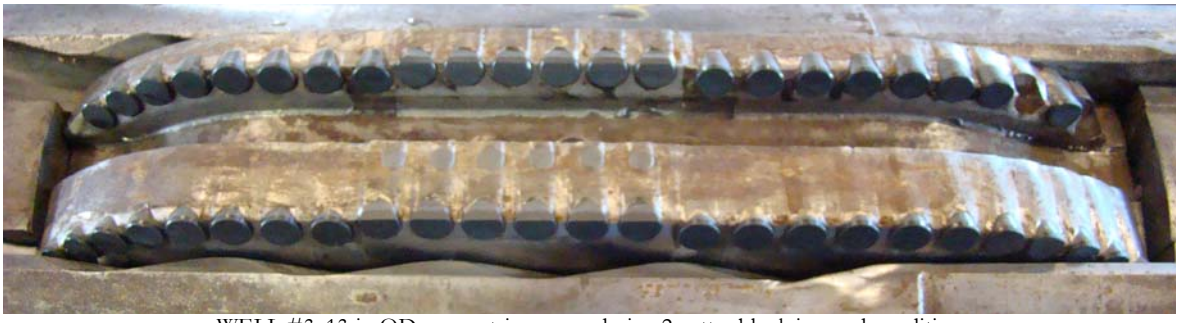



Figure 12 - Road map for WELL #3 drilling operation



WELL #2, 13-in OD concentric reamer design 1 cutter block with severely damaged lower cutter block (r)



WELL #3, 13-in OD concentric reamer design 2 cutter block in good condition

Figure 13 - Comparison of post-run cutter wearing condition, WELL #2 vs WELL #3

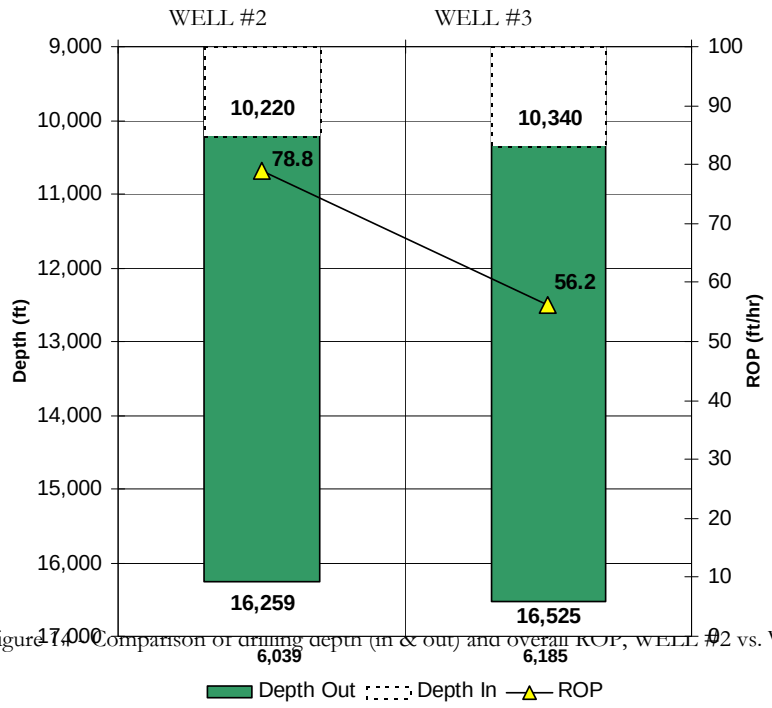



Figure 14 - Comparison of drilling depth (in & out) and overall ROP, WELL #2 vs. WELL #3

| Well | WELL #2 | WELL #3 |
|---|---|---|
| Footage Reamed (ft) | 6,039 | 6,185 |
| Interval completion time (days) | 9.66 | 7.44 |
| *Estimated Operational Costs ($US Dollars) | 7,470,000 | 5,580,000 |
| Difference ($ US Dollars) | | -1,890,000 |

Figure 15 - Comparison of overall drilling cost, WELL #2 vs. WELL #3

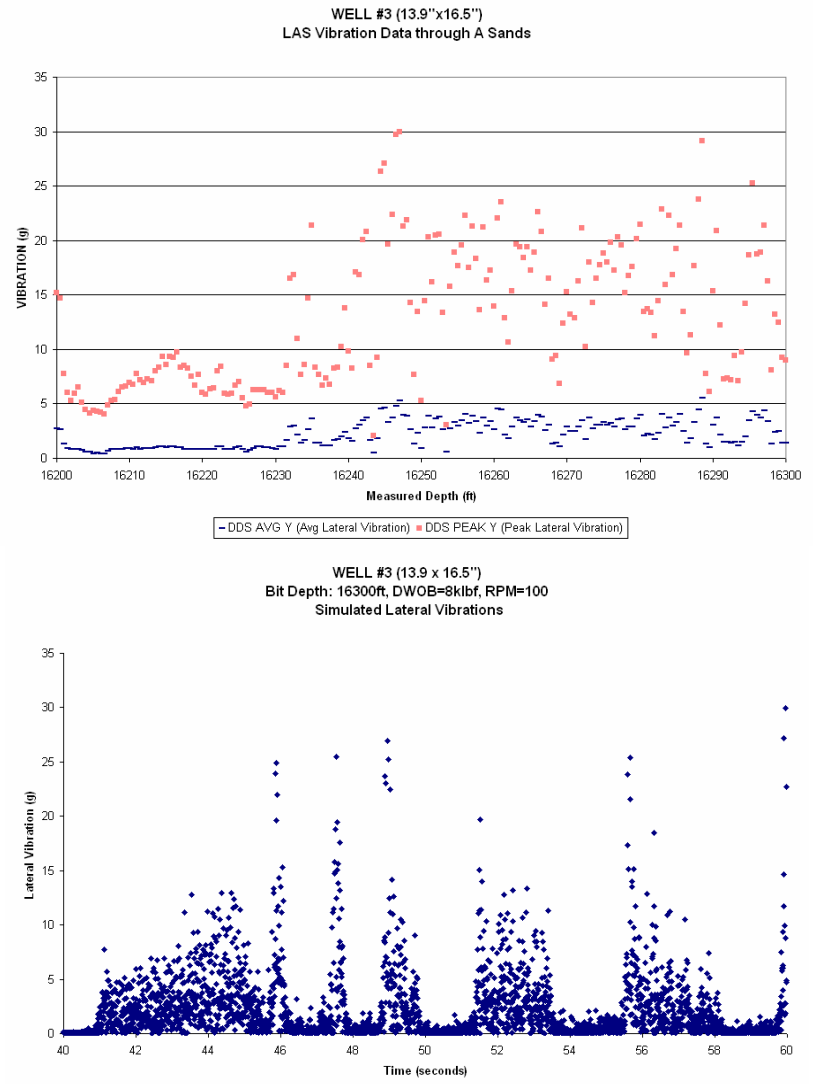



Figure 16 - Post drilling correlation between LAS drilling data and IDEAS simulation