Advances allow drillers to reach further

PIPE ROTATION EFFECTS

THE EFFECT OF pipe rotation on velocity profile and pressure drop is calculated in concentric and eccentric annulus, during the axial flow of non-Newtonian fluid. The calculations are applied to the design of hole-cleaning during drilling and cementing. The calculations are validated by comparison with measured values.

In the absence of reliable calculations, one can only guess the impact of pipe rotation on hole-cleaning. This work gives an engineer the tool to design for improved hole-cleaning and hence help save time and money during well construction and production.

The drilling community has generally realized the usefulness of pipe rotation to clean the hole both during drilling and cementing. However, no method was available to quantify the effect of pipe rotation on hole cleaning. This is because the calculation of velocity profile and pressure drop for non-Newtonian fluid is not straightforward.

Pipe rotation is more important in an eccentric annulus to remove the drill cuttings and the gelled drilling fluid from the narrow annulus. This is because, in an eccentric annulus, the fluid flows preferentially through the wider annulus.

The pipe rotation speed, ie, the RPM, equired to remove the gelled drilling fluid and the drill cuttings in various annulus configurations and eccentricities are presented. The results discussed in this paper can be applied for effective hole-cleaning during drilling and cementing. This should save nonproductive time during drilling and cementing and also nonproduction time by reducing remedial and intervention costs during well production.

Pipe Rotation and Hole Cleaning in Eccentric Annulus (IADC/SPE 99150) K Ravi, T Hemphill, Halliburton.

RISK-BASED RELIABILITY

Rotary Steerable directional drilling and logging assemblies in use today deliver significant value to operators through improved drilling efficiency, precise well placement and effective formation evaluation. System failure is often associated with a high cost and a high pain factor.

98150: Extensive field data gathered between 2003 and 2005 drove a reliability-centered design and maintenance program, which has yielded measurable improvements in rotary steerable and logging while drilling bottomhole assembly reliability and performance.

This paper describes a rigorous risk-based approach to quantify and improve the reliability and performance of directional drilling bottomhole assemblies.

Extensive field data gathered while drilling 15 million ft of hole drilled between 2003 and 2005 have been used to drive a reliability-centered design and maintenance program with the objective of improving drilling performance, improving system reliability, increasing average rates of penetration and reducing nonproductive time.

All aspects of service delivery are considered, including mechanical and electrical system component performance, repair and maintenance procedures, job design and field operating practice.

The approach has yielded measurable improvements in rotary steerable and logging while drilling bottom hole assembly reliability and performance.

Industry metrics such as mean time between failure, feet drilled per circulating hour, feet drilled between failure, failure-free runs and operating efficiency (ratio of nonproductive time to operating time) are analyzed, benchmarking current performance and setting performance expectations for existing and future downhole systems.

The industry has a need to standardize the method of evaluating downhole drilling system performance and to understand and quantify the benefits and risks associated with the application of a specific downhole system in a given downhole environment.

This paper proposes such a standard approach.

Risk-Based Reliability Engineering Enables Improved Rotary Steerable System Performance and Defines New Industry Performance Metric (IADC/SPE 98150) PA Wand, I Silvester, M Bible, Schlumberger.

SAKHALIN BIT DESIGNS

Six of the ten longest reach wells in the world have been drilled in Chayvo field on Sakhalin Island. Significant learnings have been gained from these wells and will be applied to the remaining wells to reduce cost and risk. The learnings are discussed in this paper.

The evolution of Sakhalin bit designs was driven by a variety of factors. Initial bit design focused on steerability and ROP. Intermediate bit designs reduced overall drill string torque by reducing micro tortuosity and bit torque. Current bit designs use extended gauge lengths to reduce bit darting and excessive vibrations in hard stringers while maintaining aggressive cutting structures.

Rotary steerable reliability is important because trips for tool replacement take up to 6 days. Rotary steerable systems were improved by evaluating failures, redesigning downhole components and implementing an aggressive incentive contract based on run time. Also, by using downhole vibration measurement tools, we calibrated our understanding of drill string vibrations leading to increased rotary steerable life and ROP.

Initial wells required extensive backreaming to make connections and trips. The drill team modified bit designs, BHA configurations and operations practices to minimize the amount of backreaming and achieve One Pass Trippable Hole.

Torque reduction became a concern when torque on the second well was so high we could not drill out the 9 5/8-in. casing shoe. Many different torque reduction solutions were evaluated including mud systems, mud additives, mechanical torque reduction components and drill pipe design. A combination of these solutions reduced torque by 30 percent.

The 13 5/8-in. casing, 9 5/8-in. casing, and 7-in. liners were floated on the first wells. Evaluation of casing running friction factors allowed us to convert the 13 5/8-in. and 7-in. to conventional mud-filled casing running operations.

Initial completions were cased, cemented and perforated on coiled tubing to achieve a low skin completion with zonal isolation. After experiencing problems with production liner cementing and coiled tubing perforating, the team decided to attempt alternative completion methods. The current completion being evaluated for reservoir performance incorporates standalone screens and predrilled liner isolated by swell packers.

The Next Generation of Sakhalin Extended Reach Drilling (IADC/SPE 99131) RA Viktorin, JR McDermott, RE Rush, JH Schamp, ExxonMobil.

RINGHORNE DEVELOPMENT

Ringhorne platform in the Norwegian part of the North Sea is a challenging extended reach development, with 24 wells planned from the centrally located platform. The platform was designed to drill to 7 accumulations within 8 km with target TVDs ranging from 1,750 m to 2,000 m. The multiple separate reservoirs were insufficiently sized by themselves to support a standalone development.

The field development as of June 2005 is on its 18th well and most challenging well to date: 7,600m MD at 1,796m TVD, VS/TVD (seabed) = 4.3. The Ringhorne development was made possible by using a combination of the latest drilling technologies for extended reach drilling.

During the project-planning phase, 2 key issues related to drilling were identified and stewarded at a project management team level. The key issues involved drilling operations and drilling accuracy. For drilling operations, feasibility for extended reach casing installations, ability to drill long horizontal 8 1/2-in. hole sections due to tight margins (ie lost returns), ability to drill deep 17 1/2-in. hole sections and ability to directionally drill 24-in. hole sections were identified. For drilling accuracy, concern centered around sufficient well placement not being possible due to surveying uncertainty. This talk will highlight some of the key drilling technologies used and the structured approach applied during field development to gain experience using these.

In the second part of the talk, the paper will address key observations concerning how many large-scale development projects have fundamentally shifted more of the development risk towards drilling, particularly in extended reach programs. As such, by now relying on more complex and higher-risk well designs to achieve development objectives, how did the Ringhorne drill team effectively communicate risks to the client, ie subsurface development team and senior management.

The talk will conclude with providing an update on the ongoing D&C campaign and challenges ahead as extended reach programs in general become ever more complex.

Ringhorne Development Technologies Applied in Extended Reach Drilling: Successes, Failures, and Communicating Risks (IADC/SPE 99124) NN Musaeus, ExxonMobil.

RECORD ERD WELL

Description: Case history from a world record ERD well drilled in the North Sea from the Visund floating platform. The well was originally planned as a separate costly subsea development, but a new study showed that this well could be drilled from the existing Visund floating platform using existing subsea systems.

Application: ERD wells drilled from a floating rig. What is possible for subsea development in the future.

Results, observation, conclusion: Well 34/8 A 6T2H reached a TD of 9,082 m/29,796 ft. Horizontal reach 7484 m/24553 ft, world record from a floating installation. Water depth 335 mMSL /1,100 ft.

Low friction/torque, optimal well profile, good hole-cleaning with 180 string RPM.

DIACS completion in an ERD well. Even longer well can be drilled from subsea locations in the future. Optimal pre-planning phase with use of all service companies involved and optimal teamwork in the subsurface team using 3D visualization tools.

Significance: Subsea developments in combination with ERD wells can increase oil production and lower total development cost.

World Record ERD Well Drilled From a Floating Installation in the North Sea (IADC/ SPE 98945) A Hjelle, TG Teige, K Rolfsen, KJ Hanken, S Hernes, Statoil; Y Huelvan, Schlumberger.

3D DRILLSTRING MECHANICS

With well trajectories becoming more complex, drillstring composition being unconventional and the material being used to its operating limit, the necessity to have a tool that realistically predicts forces, bending moment and contact loads along the wellbore is essential. The conventional soft string model gives a good approximation of forces and contact loads in the drillstring for very smooth trajectories but is inappropriate when the trajectory becomes tortuous or complex.

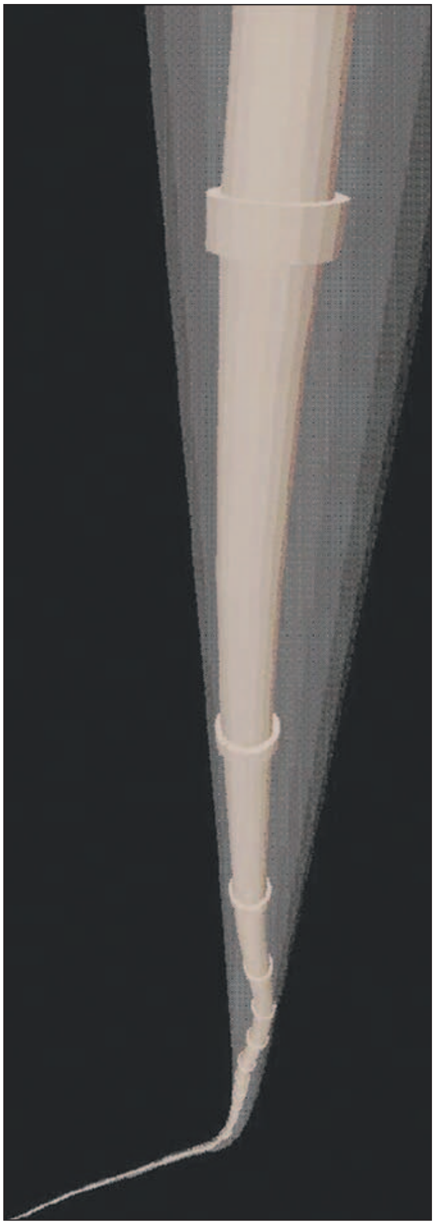
An advanced numerical method has been applied to address the 3D mechanical problem of a complete drill string moving and freely rotating inside a wellbore: computation of the unknown contacts between the drillstring and the wellbore. As this new model does not use the time-consuming finite element analysis, it can be used in real-time drilling operation at the rig to monitor torque and& drag. For the first time, it is even possible to perform simultaneously a torque and drag and directional analysis while drilling.

The power of a 3D visualization of the drillstring deformed inside the wellbore enables to localize easily contact loads on any drill string component, from the drilling bit (including side force at the bit and tilt) to the top drive or rotary table (hook load and rotary torque at surface), facilitating drilling problems analysis.

This paper will describe the fundamentals of the model developed and show the differences between the conventional soft string model and the new model in terms of tension, torque, bending moment and contact points between the drillstring and the wellbore.

With the help of the 3D visualization sofware, this paper will show the cases where the drill pipe contacts the high side of the borehole, or goes up to the right or the left side of the borehole depending on the right or left turn rate of the well trajectory.

This new model should improve significantly the torque and drag calculations and the understanding of the drillstring contributions to overall drilling performance.

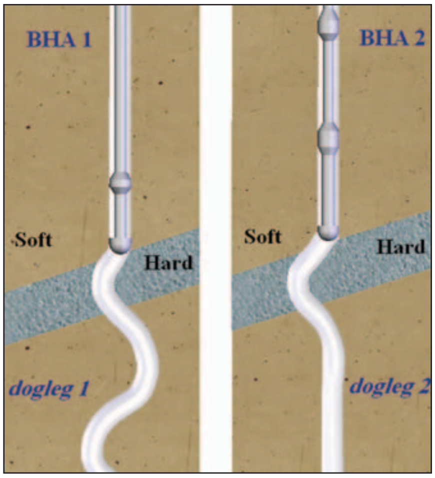


98965: An advanced numerical method has been applied to address the 3D mechanical problem of a complete drill string moving and freely rotating inside a wellbore — computation of the unknown contacts between the dril string and the wellbore.

Advancements in 3D Drillstring mechanics: From the Bit to the Topdrive (IADC/SPE 98965) S Menand, H Sellami, M Tijani, Paris School of Mines; DC Dupuis, Pride Forasol; C Simon, Drillscan.

FORMATION ANISOTROPY

Interbedded formations are a major cause of borehole tortuosity. In some fields, shale formations have a tendency



98865: Coupling a 3D rock bit model with a 3D BHA model allows prediction of the occurrence of tortuosity and to evaluate, feet by feet, the response of all directional drilling systems.

to cause wellbore deviations to undesired directions.

The formation anisotropy modifies the rock bit and the bit string interactions. Those interactions have to be understood to eliminate tortuosity. A program has been carried out using drilling bits in different formations (hard/soft, soft/hard with different interface angles).

Coupling a 3D rock bit model with a 3D BHA model enables prediction of the occurrence of tortuosity at a small and large scales and to evaluate the response of all directional drilling systems. Deviations caused by formation anisotropies are separated into two phenomena.

An initial deviation is caused by the rock bit interaction. The experimental and theoretical results explain how the gauge length, bit profile and dip angle can affect the amplitude of this deviation. A second deviation is generated when the different stabilizers are sliding through the initial one. They can be amplified or attenuated according to drilling system used. The number of stabilizers and their positions, BHA characteristics and bit steer ability affect on these deviations.

A post analysis of some real drilling cases, showed that, for a given drilling conditions including the formations anisotropies, it is possible to select the best drilling system minimizing the well tortuosity.

Effect of Formations Anisotropy on Directional Tendencies of Drilling Systems (IADC/SPE 98865) R Boualleg, H Sellami, S Menand, Paris School of Mines; C Simon, Drillscan.