ARMA 17-591

Complete Geomechanical Property Log from Drilling Data in Unconventional Horizontal Wells

Tahmeen, M.
Rocsol Technologies Inc., Calgary, Alberta, Canada
Love, J.
Oklahoma State University, Stillwater, Oklahoma, USA
Rashidi, B.
Rocsol Technologies Inc., Calgary, Alberta, Canada
Hareland, G.
Oklahoma State University, Stillwater, Oklahoma, USA

ABSTRACT: Geomechanical properties are important for reservoir characterization and optimal stimulation design in the oil and gas industry**.** The conventional techniques, such as laboratory core analysis and downhole acoustic/wireline logging can be expensive and sometimes uncertain to process for unconventional reservoirs. In this study, a convenient and cost-effective technology is presented that uses routinely available drilling data to calculate the geomechanical properties without the need for downhole logging operations. A wellbore friction model is used to estimate the coefficient of friction and effective downhole weight on bit (DWOB) from the routinely collected drilling data. The inverted rate of penetration (ROP) models use the estimated downhole weight on bit and formation lithology constants to calculate the geomechanical properties throughout the horizontal reservoir formations such as confined compressive strength (CCS), unconfined compressive strength (UCS), Young's modulus, permeability, porosity and Poisson's ratio. In this article, the field case study is presented for a sample North American well applied to the lower Eagle Ford formation. The calculated geomechanical property log is also verified with tests performed on cores in reservoir rock formations.

1. INTRODUCTION

Continuous monitoring of rock mechanical and reservoir properties along the wellbore in unconventional horizontal wells demands convenient and efficient logging techniques. The conventional logging techniques involve laboratory core analysis and well logging using sonic and resistivity image logs which are not readily available for all unconventional wells (1 in 10 or 1 in 20) mainly due to associated cost, data uncertainity and time consuming to process. Moreover there are possible risks and concerns of trapping logging tools downhole in highly deviated and horizontal wells drilled in unconventional reservoirs. For many years, researchers and engineers have been investigating several models and techniques to obtain geomechanical property logs for the successful development of unconventional resrvoirs and stimulation design for maximum hydrocarbon production. The Artificial Intelligence and Data Mining (AI&DM) or data-driven models were developed to generate synthetic geomechanical information from the conventional logs in shale plays (Eshkalak et al., 2013). The conventional log data from a shale well was used for training and calibration during neural network model development to generate the synthetic logs for other wells. This model provides better performance for the wells in proximity of the training well with actual geomechanical properties. A convenient ROP model was developed to calculate rock mechanical properties such as, confined compressive strength (CCS), unconfined compressive strength (UCS) and Young's modulus (E) at each drilled depth from the routinely collected drilling data such as rate of penetration (ROP), weight on bit (WOB) and RPM (Hareland and Nygaard, 2007). In horizontal drilling, the actual downhole weight on bit differs from the measured surface WOB (obtained from on and off bottom hook load difference readings) due to the friction caused by drill string movement, rotation within the wellbore and wellbore geometry. A previously developed 3D wellbore friction model (torque and drag (T&D) model) was used to estimate the coefficient of friction and effective downhole weight on bit (DWOB) from the surface measurements of WOB, hook load, surface applied RPM along with the wellbore survey measurement, standpipe pressure and drill string information (Fazalizadeh et al., 2010).

In this article, a convenient data-driven logging technology is presented that uses the wellbore friction and inverted ROP models to calculate rock mechanical properties, such as confined compressive strength (CCS), unconfined compressive strength (UCS) and Young's modulus. In addition, the geomechanical reservoir properties which include permeability, porosity and Poisson's ratio are obtained from the calculated rock strenghts and lithology specific constants. The logging technology is basically composed of two applications, D-WOB and D-ROCK as illustrated in Figure 1.

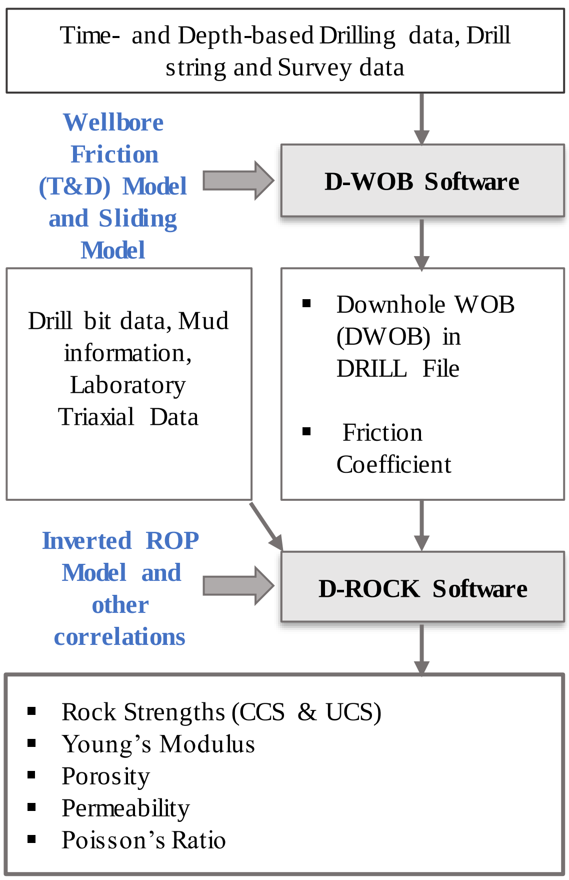

Fig. 1. Overview of data-driven logging technology

The routinely acquired time- and depth-based drilling data along with drill string information and survey data are the inputs D-WOB software. The outputs from the D-WOB, drill bit data, mud information and formation lithology are the inputs to the D-ROCK software to obtain the geomechanical property log. The mathematical models and other correlations are discussed in the following sections.

2. MATHEMATICAL MODELS

The wellbore friction model (T&D model) is used to calculate coefficient of friction and DWOB in rotary drilling mode and a sliding model is used when the drilling is performed in a sliding mode. The inverted ROP models and other correlations are then used to generate geomechanical property logs.

2.1. Wellbore Friction Model

The wellbore friction models (Fazalizadeh et al., 2010) were developed by considering an element of the drill string in the wellbore filled with drilling fluid and wellbore geometry. The forces considered on the drill string element are buoyed weight, axial tension, friction force and normal force perpendicular to the contact surface of the wellbore as shown in Fig. 2 (Tahmeen et al., 2014).

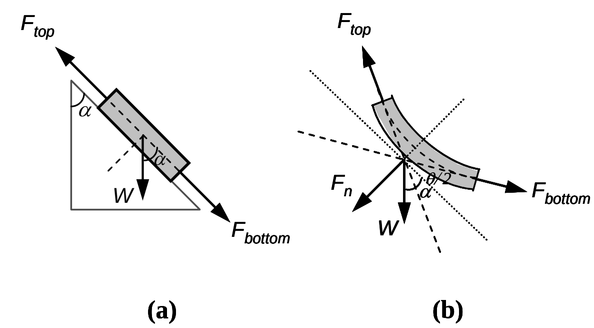

Fig. 2. Force balance on drill string elements

Figure 2 (a) and Figure 2 (b) represent the drill string element with straight inclined section and curved section respectively. The buoyed weight of drill string element is calculated as:

$$W = \beta w \Delta L \tag{1}$$

For a straight inclined section, the force balance on a drill string element when the bit is off-bottom is:

$$F_t = \beta w \Delta L \left(\cos\alpha - \mu \sin\alpha\right) + F_b \tag{2}$$

For a curved section in tension, the force balance on a drill string element is:

$$F_t = \beta w \Delta L \left[\left(\frac{\sin\alpha_t - \sin\alpha_b}{\alpha_t - \alpha_b} \right) + \mu \left(\frac{\cos\alpha_t - \cos\alpha_b}{\alpha_t - \alpha_b} \right) \right] + F_b \left(e^{-\mu|\theta|} \right) \tag{3}$$

where,

$$\cos\theta = \sin\alpha_t \sin\alpha_b \cos(\varphi_t - \varphi_b) + \cos\alpha_t \cos\alpha_b \tag{4}$$

For a curved section in compression, the force balance on a drill string element (Johancsik et al., 1984) is:

$$F_t = (\beta w \Delta L) \left[\cos\left(\frac{\alpha_t + \alpha_b}{2} \right) \right] - \mu F_n + F_b \tag{5}$$

where,

$$F_n = \left(\left[F_b(\varphi_t - \varphi_b)\sin\left(\frac{\alpha_t + \alpha_b}{2}\right) \right]^2 + \left[\begin{matrix} F_b(\alpha_t - \alpha_b) \\ + (\beta w \Delta L)\sin\left(\frac{\alpha_t + \alpha_b}{2}\right) \end{matrix} \right]^2 \right)^{1/2} \quad (6)$$

The above equations are used to calculate the coefficient of friction when the drill bit is off-bottom as well as DWOB when the drill bit is on-bottom, respectively.

2.2. *Inverted ROP Models and Other Correlations*

The developed ROP models for PDC and Rollercone drill bits take into account the effects of bit wear, drilling parameters, such as pump flow rate and RPM, and drill bit cutting structure (Hareland and Nygaard, 2007) (Rashidi et al., 2015) (Kerkar et al., 2014). By inverting and rearranging the ROP models, the rock confined compressive strength (CCS) can be defined as follows:

$$CCS = \left[\frac{ROP}{K \times DWOB^{b_1} \times RPM^{c_1} \times h_x \times W_f \times B_x} \right]^{\frac{1}{a_1}} \quad (7)$$

The unconfined compressive strength (*UCS*) and Young's modulus (*E*) are defined as,

$$UCS = \frac{CCS}{1 + a_S \times P_c^{b_S}} \quad (8)$$

$$E = CCS \times a_E \times (1 + P_c)^{b_E} \quad (9)$$

Here, a_S, b_S, a_E and b_E are formation constants calculated using laboratory triaxial test data on reservoir core samples.

The porosity and *UCS* correlation for shale formation was obtained from various shale cores and cuttings analysis (Cedola et al., 2017a) as:

$$\phi = k_1 \times UCS^{(-k_2)} \quad (10)$$

The permeability and porosity correlation for the lower Eagle Ford shale formation was obtained from trendline analysis as given below:

$$K_P = k_3 \times \phi^{k_4} \quad (11)$$

The values of k_1, k_2, k_3 and k_4 calculated for the lower Eagle Ford formation are 92.529, 0.63, 4.0302 and 2.5313, respectively. Eq. (7) to Eq. (11) are used to generate a complete geomechanical property log for horizontal wells drilled in the lower Eagle Ford reservoir only. The formation constants used in Eq. (8) to Eq. (11) need to be calculated for different formations and reservoirs.

3. INPUTS FOR ROCK STRENGTH ANALYSIS

The following inputs are required for the D-WOB software to estimate coefficient of friction and downhole WOB:

- Drilling data: date & time, measured/hole depth, bit depth, weight on bit (WOB), hook load, rate of penetration (ROP), rotary RPM, stand pipe pressure (SPP), flow rate, differential pressure and pore pressure
- Survey data: measured depth, true vertical depth (TVD), inclination and azimuth
- Drill string configuration: lengths, inner diameter, outer diameter and unit weights of drill string sections such as, bit and bottom hole assembly (BHA) components, drill pipes (DP) and heavy weight drill pipes (HWDP)
- Additional data: weight of travelling block, number of lines, single sheave efficiency and mud weight

The D-ROCK software uses the following inputs to calculate rock strengths and rock geomechanical ptoperties including porosity, permeability and Poisson's ratio:

- Drill data: output data file from D-WOB including measured/hole depth, TVD, downhole weight on bit, ROP, RPM, SPP, flow rate, pore pressure and mud weight
- Drill bit data: type of drill bit (PDC or Rollercone), bit diamater, IADC code, bit wear in and wear out, number and diameter of bit nozzles
- Mud and formation data: drilling mud type (water or oil), mud motor constants and type of formation
- Laboratory triaxial data: confining pressure, CCS, average UCS and Young's modulus

In this article, the field case study is presented for a sample North American well applied to the lower Eagle Ford formation. A well with doglegs up to 10 degrees per 30m and heel at around 2580m is presented and the analysis was performed for the depth interval from 2640m to 3460m in the horizontal section. The wellbore geometry used for this rock strength analysis was identified from the directional survey measurements of this horizontal well and is depicted in Figure 3.

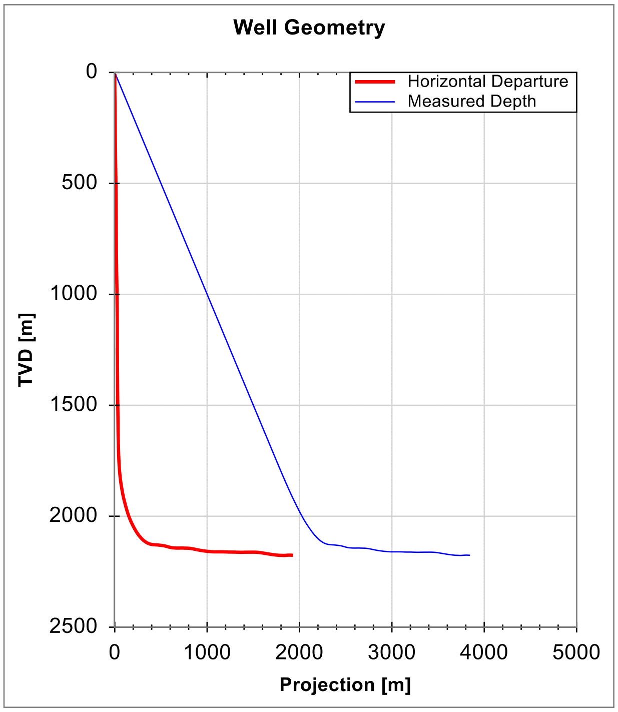

Fig. 3. Wellbore geometry of horizontal well

4. GEOMECHANICAL PROPERTY LOG

The mathematical models defined in Eq. (1) to Eq. (6) were used to calculate downhole WOB in rotary drilling mode using D-WOB. The models in Eq. (7) to Eq. (11) were utilized in the D-ROCK software to calculate geomechanical properties of the reservoir formation.

4.1. Downhole WOB (DWOB) Calculations

The routinely collected depth-based, 10 second time-based drilling data from the horizontal test well and additional data required for D-WOB software were used to estimate coefficient of friction along the wellbore from the time-based off-bottom drilling data. The downhole weight on bit was calculated using the estimated friction coefficient, depth-based on-bottom drilling data and other required inputs. Figure 4 shows the difference between surface measured WOB (SWOB) and calculated DWOB using the T&D model. The spikes in the weight on bit profile represent the higher WOB in the sliding mode.

For the selected depth interval from 2640m to 3460m in the horizontal section, the friction coefficient was calibrated at each connection and the estimated values range from 0.09 to 0.18. The calculated effective DWOB was observed around 77.6% of the surface measured WOB (SWOB). The calculated DWOB values utilizing the T&D models were verified with the downhole weight on bit measurements obtained from the CoPilot downhole tool as shown in Figure 5.

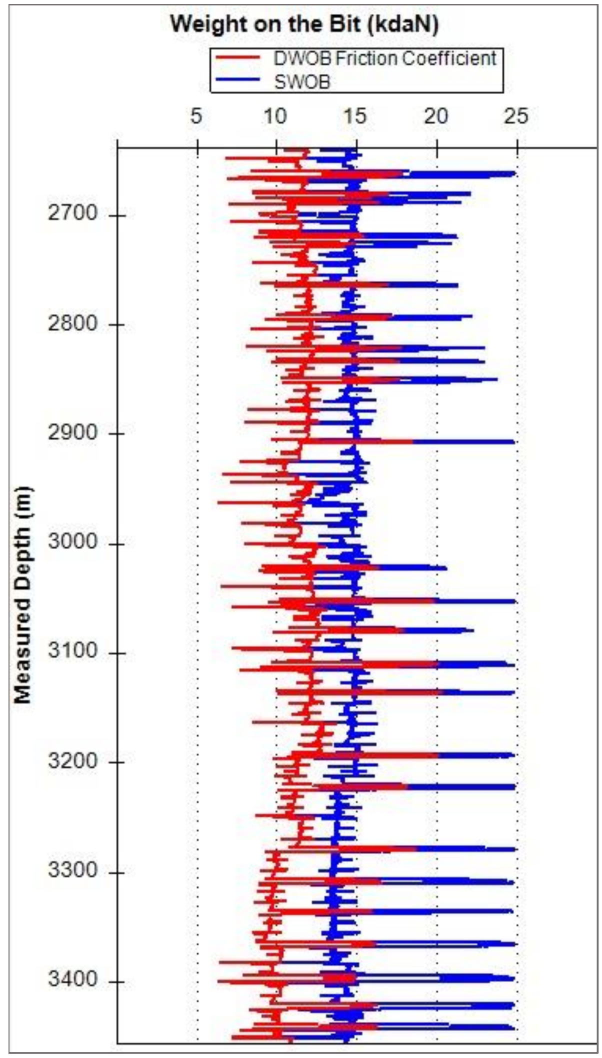

Fig. 4. Downhole WOB (DWOB) profile from D-WOB software

The sliding sections in Figure 5 shows higher values of surface measured WOB (blue plots). The weight on bit measurement with the CoPilot downhole tool is presented by the green plots. It can be observed, there exist significant differences between the calculated DWOB using T&D models (red plot) in sliding sections and the corresponding downhole measured WOB (green plot) as shown in Figure 5(a). The results from the T&D models show encouraging match in rotary drilling mode but not so good in the sliding drilling mode. Therefore, a sliding model was developed as a function of differential pressure across the mud motor (DP) a sliding constant K_s (Wu and Hareland, 2015). In this article, a slightly modified sliding model is used as given below:

$$DWOB_{sliding} = K_s \times DP \tag{12}$$

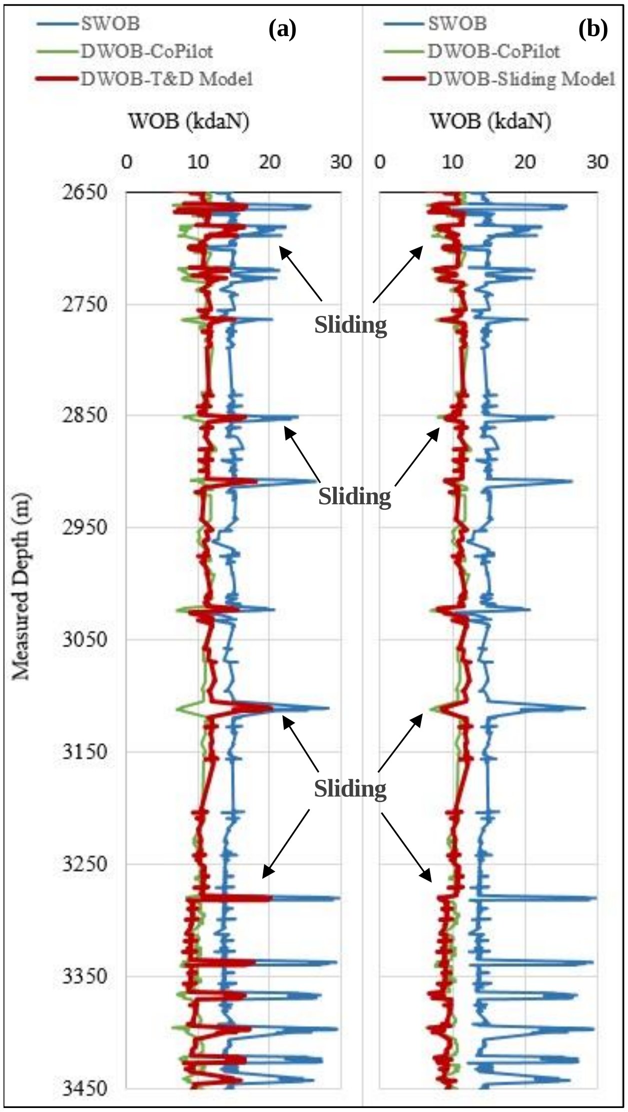

Fig. 5. Comparison of calculated DWOB with the measurement from CoPilot downhole tool

The sliding constant K_s, is obtained from the relationship of differential pressure (DP) and the corresponding T&D model based DWOB estimated during the immediate rotary drilling process. In the sliding mode, the calculated DWOB using the sliding model ($DWOB_{sliding}$) showed better agreement with the downhole measured WOB data as presented in Figure 5(b). In Figure 5(b), the red plot (DWOB-Sliding Model) represents the DWOB calculated from the T&D model and sliding model for rotary drilling and sliding drilling mode in the horizontal section of the well, respectively.

4.2. Rock Strength Log Generation

The output from the D-WOB software was applied to the PDC or Rollercone inverted ROP drill bit models with several bit parameters and used in the D-ROCK software to generate rock strength log. In this paper, the drilling data of a sample horizontal well in the lower Eagle Ford formation was used and the outputs were analyzed to illustrate the capabilities of the D-ROCK software. The formation constants required to obtain the geomechanical properties were calculated from the laboratory test data on lower Eagle Ford formation cores. In Figure 6, the unconfined compressive strength (UCS) and Young's modulus logs were generated utilizing DWOB calculated from the combined models for both rotary drilling and sliding mode.

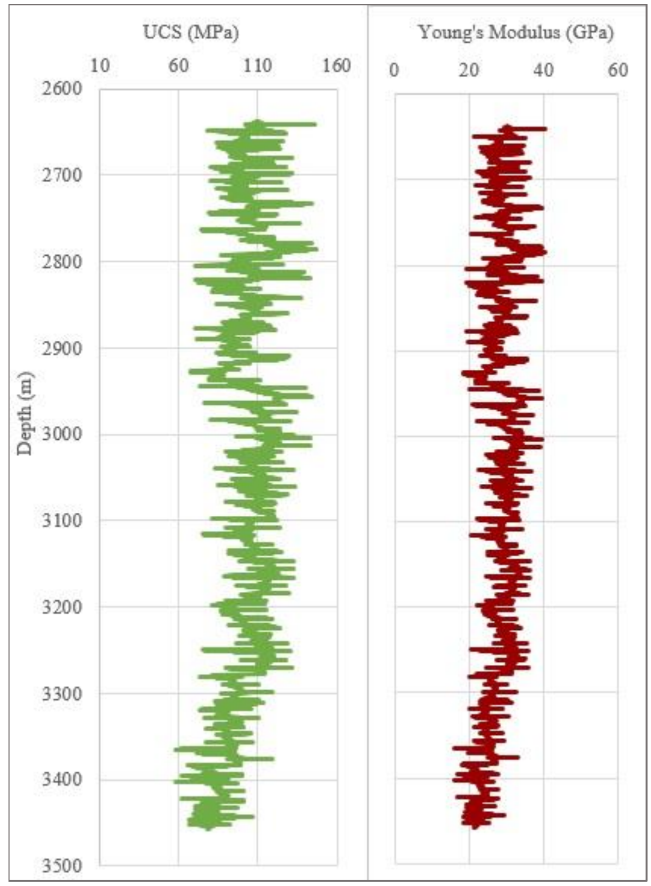

Fig. 6. UCS and Young's modulus logs from D-ROCK software

The decreasing UCS profile after 2900 m indicates softer formation towards the toe of the wellbore in horizontal section. In this case study, the average values of UCS and Young's modulus were found to be 102.48 MPa and 28.21 GPa, respectively. Sone reports Young's modulus values for the lower Eagle Ford in the range from 25 to 34 GPa (Sone, 2012).

In this study, the geomechanical properties of Eagle Ford shale formation including porosity, permeability and Poisson's ratio were investigated to verify the D-ROCK models as defined in Eq. (10) and Eq. (11). The rock failure envelope for the lithology specific to lower Eagle Ford constants was used to calculate the rock failure angle and Poisson's ratio (Hareland and Hoberock, 1993). The regression analysis of Eq. (8) and Eq. (9) were performed to calculate the formation constants utilizing the mechanical test data for the Eagle Ford formation (Hu et al., 2014) as shown in Figure 7.

The porosity vs. permeability relationships obtained from the D-ROCK software were verified with the reported upper and lower bound trends of the Eagle Ford formation (Ramirez and Aguilera, 2016) (Aguilera, 2014) as depicted in Figure 8.

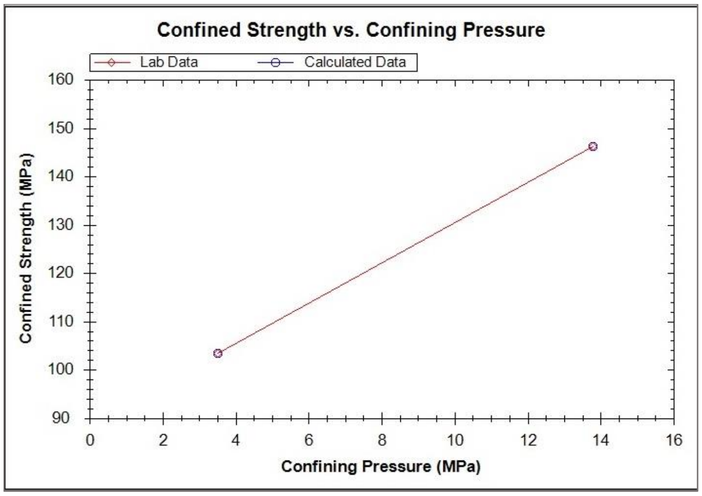

Fig. 7. Laboratory data analysis to obtain constants for the Eagle Ford formation

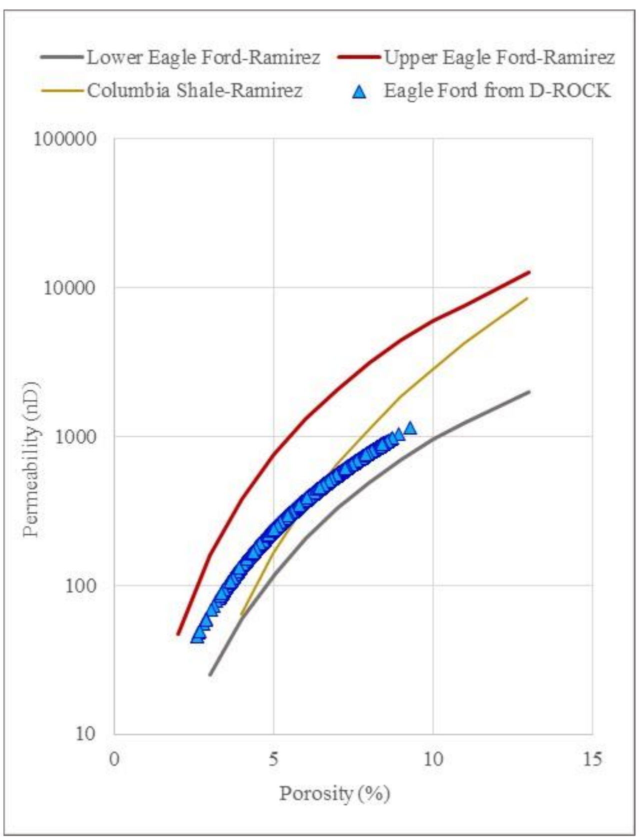

Fig. 8. Porosity and permeabilty relationships for Eagle Ford formation

In Figure 8, the permeability vs. porosity relationship generated from the D-ROCK models (blue triangles) indicated the location of the horizontal well near the lower Eagle Ford formation. A shale formation in Columbia is also plotted for comparison purposes.

The porosity, permeability and Poisson's ratio vs. measured depth for the lower Eagle Ford formation are also shown in Figure 9 and Figure 10, respectively.

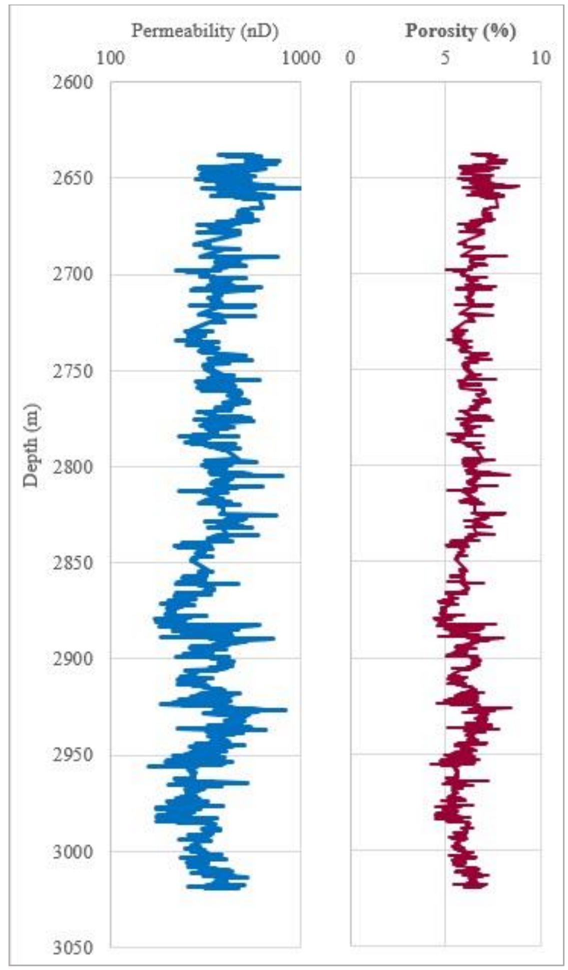

Fig. 9. Permeabilty and porosity vs. measured depth for Eagle Ford formation

The higher porosity was observed at several depth intervals and indicates possible sweet spots in the lower Eagle Ford shale reservoir.

In future studies, the porosity model in D-ROCK for shale formation will be improved by incorporating gamma ray porosity correlations (Cedola et al., 2017b) for more accurate analysis of the geomechanical properties in unconventional shale reservoirs.

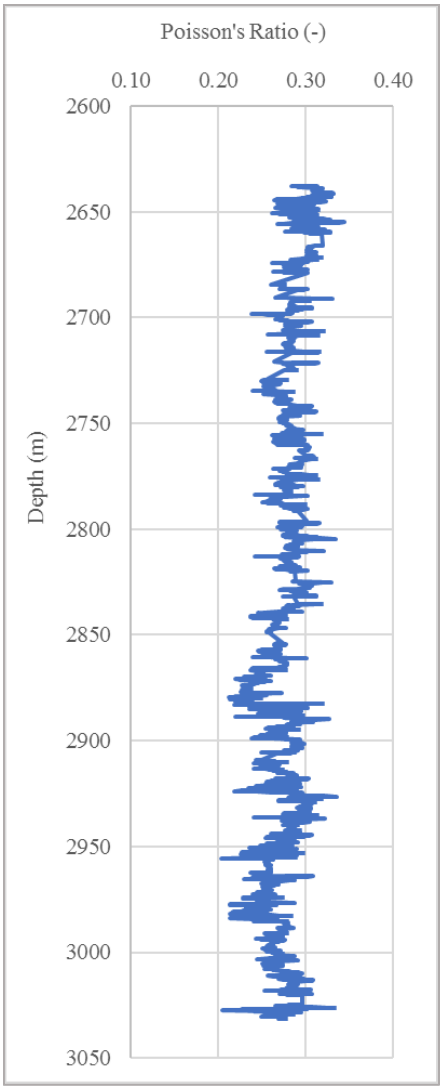

Fig. 10. Poisson's ratio vs. depth for Eagle Ford formation

5. CONCLUSIONS

In this article, a convenient and cost effective logging technology was presented to obtain complete geomechanical property log from the routinely acquired drilling data in a sample horizontal well drilled through unconventional shale reservoir. The wellbore friction model and inverted ROP models were utilized to calculate the coefficient of friction along the wellbore, effective downhole weight on bit and rock geomechanical properties, respectively. A good agreement was observerd between the estimated downhole weight on bit and the weight on bit obtained using a downhole measuring tool (CoPilot). The calculated geomechanical property log was compared to actual laboratory determined rock properties and therefore reveals the validation of this convenient well logging technique.

The information in the rock property logs can be used as inputs to map sweet spots and optimize the hydraulic fracturing process for maximize well productivity and NPV (Net Present Value). The geomechanical property logs generated from this data-driven technology can potentially lead to optimized completion and stimulation design of the shale reservoir, using only drilling data collected during normal drilling operations at no additional cost.

6. NOMENCLATURE

a_1, b_1, c_1: drill bit constants

a_S, b_S, a_E, b_E: formation constants obtained from regression analysis

B_x: function of drill bit properties

D_b: diameter of bit

E: Young's modulus

F_t, F_b: force or hook load at top and bottom, respectively

F_n: net normal force acting on the drill string element

h_x: hydraulic efficiency function

K: empirical constant in ROP model

K_p: permeability

K_s: sliding model constant

ΔL: element length of drill string

P_c: confining pressure

w: unit weight of drill string element

W: buoyed weight

W_f: bit wear function

α_t, α_b: inclination at top and bottom, respectively

β: buoyancy factor

μ: coefficient of friction

φ_t, φ_b: azimuth at top and bottom, respectively

θ: dogleg angle

ϕ: porosity

REFERENCES

1. Aguilera, R. 2014. Flow units: from conventional to tight-gas to shale-gas to tight-oil to shale-oil reservoirs. *SPE Reservoir Evaluation & Engineering, May, University of Calgary, Calgary, Canada, 2014*.

2. Cedola, A. E., Atashnezhad, A. and Hareland, G. 2017a. Evaluating multiple methods to determine porosity from drilling data. *SPE Oklahoma City Oil and Gas Symposium, 27-30 March, Oklahoma City, Oklahoma, USA*, 2017.

3. Cedola, A. E., Atashnezhad, A. and Hareland, G. 2017b. Real-time porosity from surface drilling data prediction

and verification. *AADE-17-NTCE-134, 2017 AADE National Technical Conference and Exhibition, 11-12 April, Houston, Texas, USA*, 2017.

4. Eshkalak, M.O., Mohaghegh, S. D. and Esmaili, S. 2013. Synthetic, geomechanical logs for Marcellus shale. *2013 SPE Digital Energy Conference and Exhibition, Woodlands, Texas, USA, 5-7 March, 2013.*

5. Fazaelizadeh, M., Hareland, G. and Aadnoy, B. S. 2010. Application of new 3-D analytical model for directional wellbore friction. *Modern Applied Science*, 4: 2, 2-22

6. Hareland, G. and Nygaard, R. 2007. Calculating unconfined rock strength from drilling data. *ARMA-07-214, 1st Canada-US Rock Mechanics Symposium, 27-31 May, Vancouver, Canada, 2007*.

7. Hareland, G. and Hoberock, L. 1993. Use of drilling parameters to predict in-situ stress bounds. *SPE 25727, SPE/IADC Drilling Conference, Amsterdam, Netherlands, 1993*.

8. Hu, D., Matzar, L. and Martysevich, V. 2014. Effect of natural fractures on Eagle Ford shale mechanical properties. *SPE-170651-MS, SPE Annual Technical Conference and Exhibition, 27-29 October, Amsterdam, The Netherlands, 2014.*

9. Johancsik, C. A., Friesen, D. B. and Dawson, R. 1984. Torque and drag in directional wells – prediction and measurement. *J. of Petroleum Technology, SPE 11380,* 987-992.

10. Kerkar, P., Hareland, G., Fonseca, E., Hackbarth, C., 2014. Estimation of Rock Compressive Strength Using Downhole Weight-On-Bit and Drilling Models. *IPTC 17447, International Petroleum Technology Conference, 20-22 January, Doha, Qatar, 2014.*

11. Ramirez, J. F. and Aguilera, R. 2016. Factors controlling fluid migration and distribution in the Eagle Ford shale. *SPE Reservoir Evaluation & Engineering, August, University of Calgary, Calgary, Canada, 2016*.

12. Rashidi, B., Hareland, G., Wu, Z., 2015. Performance, Simulation and Field Application Modeling of Rollercone Bits. *J. of Petroleum Science and Engineering, 133-(2015) 507-517*

13. Sone, H., 2012, Mechanical properties of shale gas reservoir rocks and its relation to the in-situ stress variation observed in shale gas reservoirs: Ph.D. thesis, Stanford University.

14. Tahmeen, M., Hareland, G. and Aadnoy, B. S. 2014. Real-time software to estimate friction coefficient and downhole weight on bit during drilling of horizontal wells. *ASME 2014 33rd International Conference on Ocean, Offshore and Arctic Engineering, OMAE2014, June 8-13, San Francisco, California, USA*, 2014.

15. Wu, Z. A. and Hareland, G. 2015. Real-time downhole weight on bit (DWOB) automation in directional drilling. *ASME 2015 34th International Conference on Ocean, Offshore and Arctic Engineering, OMAE2015, May 31-June 5, St. John's, Newfoundland, Canada*, 2015.