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Real-Time Proactive Optimal Well Placement Using Geosignal and Deep Images
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A Message from Greg Powers

Welcome to the fifth edition of Reservoir Innovations. This technology journal is filled with valuable information on formation evaluation that reveals new ways to increase reservoir understanding, add value and deliver results. This issue includes recent major industry papers written by Halliburton specialists and our clients, through industry organizations such as the SPE and SPWLA.

Applying current and future technology to solve our customers’ challenges and to increase asset value is at the heart of everything Halliburton does. That’s why our patent filings have virtually tripled in three years. We are committed to helping you find better ways to solve your challenges. With that goal, Halliburton is developing new technologies to reduce uncertainty, increase access and ensure superior execution.

To achieve these objectives, we have created a diverse technology organization to maximize opportunities for collaboration. Our technology centers around the world – combined with a mobile workforce – ensure that highly experienced individuals with varied backgrounds work together to create the best solutions.

For example, one of our paper selections, “Field Evaluation of LWD Resistivity Logs in Highly Deviated and Horizontal Wells in Saudi Arabia” explores how Halliburton worked closely with the operator to solve the challenge of boundary artifacts, which can make resistivity interpretation difficult. Working together, the team developed a new interpretation and processing methodology that simplified the process and mitigated the effects of boundary artifacts improving the ability to determine true formation resistivity for more accurate hydrocarbon saturation results.

And in highlighting our commitment to delivering customized solutions, the paper, “Optimizing Perforating Charge Design for Stimulation” demonstrates the value of custom perforation designs and introduces a new class of shaped charges that has proven to optimize fracturing efficiencies. These charges were designed at the Halliburton Perforating Center of Excellence, where our unique Perforating Flow Laboratory can simulate actual well conditions and pressures in the world’s most challenging environments. The lab provides insight into physical phenomena occurring in the reservoir during complicated perforating and multiphase flow events. It’s already providing operators with information needed to design custom perforation systems and solutions that optimize production.

On behalf of David Topping and Ahmed Kenawi, I encourage you to collaborate with our staff to coauthor future papers that highlight your challenges. As always, we welcome your questions and feedback on our publications. We sincerely hope you find them valuable and enjoyable.

Thank you,

Greg Powers,
Vice President, Technology

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On the Cover

The Halliburton multidetector TMD-3D™ tool is a 1 1/16 inch-OD pulsed neutron-induced gamma ray logging system, designed to measure saturation in a through-tubing cased hole environment. In tight gas unconventional reservoirs, the service provides the best gas sensitivity with low salinity and lithology dependence, compared to all other current offerings. In mature reservoirs, it quantifies hydrocarbon saturation with the best depth of investigation in mid- to high-water salinity, due to the fast-response scintillation detectors and high-speed electronics.

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Field Tests of a New Optical Sensor Based on Integrated Computational Elements for Downhole Fluid Analysis

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Abstract

Optical fluid analyzers have been used in wireline formation tests for real-time downhole fluid analysis during pumpout tests for over a decade. Based on conventional optical spectroscopic methods, they separate broadband light into its constituent wavelengths via notch filters or multichannel grating spectrometers. A few narrow wavelength constituents are then detected and mathematically recombined to yield an answer product. Complex hydrocarbon fluids have many overlapping spectra and are optically active over a wide range of optical wavelengths. Consequently, accurate analyte detection in hydrocarbon fluids generally requires analysis of a large number of wavelengths over a large spectral region. The performance and range of detectable analytes of conventional optical fluid analyzers is band-limited. Of all available spectra from visible to near- and mid-infrared, only a small fraction of spectral data is used. In addition, the splitting of the optical beam into its wavelength constituents typically decreases signal-to-noise ratios (SNR) by orders of magnitude thereby limiting the accuracy, sensitivity, and viable ranges of the answer product.

A new downhole optical sensor platform has been developed for downhole in-situ fluid analysis based on multivariate optical computing (MOC) technology. Historically developed for other markets, MOC is a well-established tool that combines chemometrics and pattern recognition with the power of optical computing. The heart of this new optical sensor platform is an optical component called the ICE Core™ integrated computational element. The ICE Core sensor is analogous to the processing chip of a PC and performs calculations literally at the speed of light within the multivariate optical computer. Each ICE Core special multilayer optical element is encoded with a pre-designed multivariate regression vector specific to an analyte or property of interest. These optical elements are typically very broadband and may have a response that extends from 400 nm to 5000 nm. The wide bandwidth of these optical elements combined with their intrinsic, high etendue SNR advantage enables laboratory-grade optical analyses downhole. The compact and passive nature of the ICE Core sensors results in high reliability. A multivariate optical computer may consist of many different ICE Core sensors designed to detect many different analytes or properties. The downhole optical sensor platform in this study can have 20 (or more) different ICE Core sensors per MOC. This platform has been under field trial qualification for over a year using a step-by-step process with methane (C1) ICE Core sensors as the primary validation analyte.

In this paper, the results of three different downhole pumpout field trials are presented. After reviewing the fundamental principles of MOC and ICE Core technology, the field trial validation process is described. Results showing downhole ICE Core measured methane analyte concentrations vs. time are presented and compared with other downhole sensor data. ICE Core measured concentrations are also compared with independent laboratory test results. The results demonstrate the downhole viability of the optical platform and the sensitivity associated with the ICE Core detection method.

Introduction

Analysis and characterization of reservoir fluids are essential for petroleum asset management. Samples of representative formation fluids are analyzed to determine the bulk fluid properties, fluid phase behavior, and chemical properties. This information is then used to design production strategies, identify and mitigate flow assurance issues, and is used as a key parameter in determining the value and economic viability of a play. Costly exploration wells are often drilled solely for evaluation purposes, and the only fluids recovered will be the samples captured by a downhole pumpout wireline formation tester (PWFT). With such high stakes placed on the capture of these samples, and with so many high-value decisions incumbent on the data from these samples, capturing high-quality reservoir samples is clearly one of the most imperative objectives for any wireline pumpout formation tester job (Elishahawi 2007).

The quality of fluid samples is adversely affected by drilling fluid filtrate. During the drilling process, drilling fluid invades the formation near the wellbore. This invasion process is dependent on factors such as the pressure difference between the mud column and the formation pressure, the permeability of the formation, fluid loss properties of the drilling mud, etc. In the case of sampling hydrocarbons in the presence of an organic-based drilling mud (OBM), it may be quite difficult to distinguish OBM from formation fluid with conventional physical property sensors such as resistivity sensors and capacitance sensors. The same is true for density sensors, unless there is sufficient difference between the OBM filtrate and formation fluid such that the difference is well within the resolution power of the density sensors.

In contrast, there are almost always differences in chemical composition between drilling fluid filtrate and formation fluid. Optical sensors can be highly sensitive to chemical composition, thus an optical sensor presents a powerful, additional way to measure the chemistry of the formation fluid downhole and in real time by chemically differentiating between the OBM filtrate and reservoir fluid. Optical sensors, specially designed to accurately detect unique formation fluid components will improve the formation fluid characterization with use of downhole formation testing tools.
Multivariate Optical Analysis

The principles of multivariate analysis and multivariate optical analysis are well established. The absorption of light by matter is described by the well-known Beer-Lambert law:

$$A(\lambda) = \varepsilon(\lambda) \cdot L \cdot c$$  \hspace{1cm} (1)

where $A(\lambda)$ is the wavelength-dependent absorbance of light, $\varepsilon(\lambda)$ is the chemical-specific rate of attenuation known as the molar absorptivity coefficient, $L$ is the optical path length, and $c$ is the concentration of the material the light traversed. The absorbance of light is related to the fractional transmittance by the equation:

$$T(\lambda) = 10^{\frac{-A(\lambda)}{2.303}}$$  \hspace{1cm} (2)

where $I_0$ is the intensity of light impinging the material and $I$ is the intensity of light resultant from the material. Since absorptivity is additive, for a fluid consisting of multiple components $i$ ($i = 1, 2, ..., M$) each with attenuation $e_i(\lambda)$ and concentration $c_i$, we can write:

$$A(\lambda) = \sum e_i(\lambda) \cdot c_i$$  \hspace{1cm} (3)

It then follows that if absorptivity is measured at multiple wavelengths $\lambda$ ($i = 1, 2, ..., M$), using matrix notation, we have:

$$\begin{bmatrix} A_{\lambda_1} \\ A_{\lambda_2} \\ \vdots \\ A_{\lambda_M} \end{bmatrix} = \begin{bmatrix} e_{1\lambda_1} & e_{2\lambda_1} & \cdots & e_{M\lambda_1} \\ e_{1\lambda_2} & e_{2\lambda_2} & \cdots & e_{M\lambda_2} \\ \vdots & \vdots & \ddots & \vdots \\ e_{1\lambda_M} & e_{2\lambda_M} & \cdots & e_{M\lambda_M} \end{bmatrix} \cdot \begin{bmatrix} c_1 \\ c_2 \\ \vdots \\ c_M \end{bmatrix}$$  \hspace{1cm} (4)

We can rewrite the left side of Eq. 4 as the measured signal $S$ with the objective of finding a regression set of coefficients as a vector $R_v$ such that $S = R_v \cdot C$. In other words, $R_v^\top \cdot S = C$ for an individual sample. Let $X$ be an experimentally measured matrix of $S$ for an array of $C$ respective concentrations, then $R_v$ may be found as:

$$R_v = (X^\top X)^{-1} X^\top C$$  \hspace{1cm} (5)

for a matrix $X$ of sufficient rank. More generally, $X$ may be transformed prior to the solution of a linear system of equations as any set of orthogonal eigenvectors. Note that $R_v$ is not a unique solution but may be optimized for various conditions. Classical Least Squares, Principal Component Regression, Partial Least Squares, and Alternating Least Squares are a few of the many methods of regression vector optimization.

Once a regression vector is determined, a classic regression may be performed as a dot product of the regression vector with the spectrum of a sample to determine the concentration:

$$C = R_v \cdot I$$  \hspace{1cm} (6)

where $C$ is the concentration, $R_v$ is the regression vector, and $I$ is the light spectrum of the sample (Thomas 1994).

The key element of Eq. 6 is the regression vector, also known as a pattern recognition vector or correlation vector. Regression vectors have been ubiquitously employed in a wide variety of industries for more than 50 years. A typical multivariate regression vector is a complex function of wavelength, as shown in Fig. 1. Note the positive and negative coefficients for each regression vector. Also note the similarity of the two regression vectors, Partial Least Squares (PLS), and Principal Component Regression (PCR). PLS and PCR use different optimization routines to solve for analytic regression vectors. These regression vector shape commonly contains many high-frequency peaks and valleys. Regression vectors are unique to a specific analyte or characteristic of interest. Finally, we note that multivariate regression vectors have both positive and negative values.

Multivariate Optical Computation

Multivariate optical computers (MOC) perform computations using a light source and principles that are well known and remarkably simple. When light of intensity $I_0(\lambda)$, propagates through an optical element with transmission function $T(\lambda)$, the intensity of the light emerging from the optical element $I(\lambda)$ is the dot product given by:

$$I(\lambda) = I_0(\lambda) \cdot T(\lambda)$$  \hspace{1cm} (7)

This dot product operation is literally performed at the speed of light, and detection of the light using standard detectors enables the quantification of $I(\lambda)$. If the transmission function $T(\lambda)$ is the regression vector $R_v(\lambda)$, then the concentration $C$ in Eq. 6 may be instantaneously calculated using light since:

$$I(\lambda) = I_0(\lambda) \cdot R_v(\lambda) = C \cdot I(\lambda) = C$$  \hspace{1cm} (8)

Thus, the measurement of the intensity of the light emanating from a material and passing through an optical element whose transmission function is a regression vector is a direct measure of the concentration of the analyte of interest in that material.

It is well established that a regression vector may be encoded optically as the transmission function of an optical element by means of an interference layer-thin film stack (Haibach 2003). Such elements have been successfully fabricated and are called ICE Core (Integrated Computational Element) due to the integrated nature of optical sensing and optical computation. These elements can then be incorporated into an optical computer and used to measure various material compositions in real time as shown in Fig. 2. By encoding a regression vector directly as the transmission function for an optical element, the response of the detector is now a direct function of an analyte of interest. Note that when the light from the source interacts with a material,
information pertaining to the composition is imparted to the light. Also note that the light is never broken up into its constituent wavelengths and therefore yields an optimal entendue and SNR advantage. The ICE Core sensor decodes this information in the optical domain literally at the speed of light. Note that in this illustration, the optical path has been simplified and the detection scheme omitted. Also note that typically a different ICE Core sensor is required for each analyte.

The advantages of multivariate optical computer and ICE Core technology are numerous:

- The unusually broadband nature of ICE Core sensors uses sensitive detection and discrimination of complex and optically similar compounds typical of hydrocarbon fluids. The broadband nature also enables many different analytes to be investigated from those active in the UV, Visible, NIR, and IR regions of the optical spectrum. The mid-infrared region, for example, coincides with fundamental signatures of many organic components.
- The inherent simplicity, small size (Fig. 3), and passive nature of the ICE Core sensor enables high reliability and operations in challenging environments such as those encountered downhole.
- In contrast to conventional methods, the light is never broken up into its constituent wavelength components. Thus, resolution errors associated with conventional spectrometers are eliminated. Additionally, the etendue of the optical system is near its theoretical maximum resulting in SNR up to orders of magnitude higher than dispersive systems enabling sensitive detection of low-concentration analytes.
- The answer product is calculated in real time and in situ thereby enabling key decisions (such as when to sample) to be made in real time.
- The answer product is calculated automatically and without subjective human interpretation. The calibrated output the detector provides is the answer product without any further analysis or human interpretation.
- The high etendue light throughput enables low power consumption and battery-powered operation.

Field Tests

ICE Core MOC platform. An optical diagram of the ICE Core multivariate optical computer platform is shown in Fig. 4. From this diagram, we see that broadband light is directed through a flow cell, through an ICE Core sensor, and onto the optical detector whose output can be employed to display the real-time concentration information. The ICE core sensor is mounted on an ICE Core carousel, which rotates various ICE Core sensors into the optical beam to measure the specific analyte or property associated with that ICE Core sensor. By rotating the carousel, multiple formation fluid component analytes can be investigated almost simultaneously. More importantly, we note that this implementation provides a platform from which ICE Core sensors can be added or changed according to the measurements desired. ICE Core sensors under development can also be added by simply adding them to the carousel. The ICE Core MOC platform, which is the subject of this paper is configured to hold at least 20 different ICE Core sensors yielding 20 different analytes’ concentrations at the same time.

A photograph of the entire ICE Core multivariate optical computer including light source, ICE Core carousel, detectors, and pre-amplifiers is shown in Fig. 5.
The primary purpose of the first field trials was to validate the ICE Core multivariate computer platform under real-world, downhole conditions. To accomplish this objective, methane ICE Core sensors were used as a validation method since methane is one of the key and most common parameters desired for real-time, downhole fluid measurement. Methane is also a ubiquitous analyte in a wide variety of formation fluids. It exists in high-concentration gaseous states as well as medium-concentration hydrocarbon condensates and oils and in trace concentrations in formation waters. Using methane for the first ICE Core sensors therefore enabled a wide variety of downhole field tests to be conducted in a wide variety of downhole formation fluids across the world.

The ICE Core MOC platform was calibrated and then built into a wireline formation tester (WFT) for fluid analysis during formation pumpout and sampling operations. Three field trials in three locations were then conducted using the WFT over a period of about 3 months. Figs. 6a, 6b, and 6c show the WFT configuration for Field Tests 1, 2, and 3 respectively.

Field Test Results
The mechanical, electrical, and optical subsystems associated with the ICE Core MOC platform all performed as designed for all three field tests.

Field Test 1. This test sampled a gas reservoir in the presence of OBM. Six samples were acquired at a single depth during a single pumpout. Sample 1 was acquired for the focused sampling configuration of the probe position only. Sample 2 was acquired in a comngled probe/guard position. Samples 3 through 6 were acquired in a focused sampling configuration with the pump at maximum rate and the guard at ¼, ½, ¾, and full rate, respectively. Fig. 7 shows the fluid density in the flow stream as a function of time. Periods in red show the time period of the sampling. Fluid density increases while filling the nitrogen-backed sample chambers with an overburden pressure.

The ICE Core measured methane concentration as a function of time is shown in Fig. 8 along with the WFT fluid density for the first 90 minutes of the first pump-down period. Two ICE Core
measurements are displayed: the higher speed measurement in grey and a 3-minute rolling average in black. There are several observations that can be made from the data in Fig. 8. First, we note the presence of many high-frequency oscillations in the high-speed ICE Core methane signal. These oscillations start out strong and gradually decrease over a 20-minute period. The oscillations are also synchronous with the pump frequency easily seen in the fluid density signal. The average methane concentration during the same period gradually rises from 0.15 g/cc to about 0.236 g/cc. The high-frequency fluctuations and gradual concentration increase are classic signs expected for a miscible fluid cleanup. Strong downward spikes, which decrease in amplitude are likely filter cake particles cleaning up with the volume pumped. The yellow highlighted region isolated from when spikes are minimal shows an average methane concentration of 0.236 g/cc +/- 0.003 g/cc compared to a theoretical concentration of pure methane of 0.232 g/cc. Even with the occasional spikes, the methane reading is stable after cleanup within +/- 0.011 g/cc standard deviation before the four sampling points.

The value of 0.236 g/cc compares well with the theoretical value of 0.232 g/cc for methane at given reservoir temperature and pressure conditions. In conjunction with the densitometer-measured fluid density of 0.239 g/cc, the methane concentration confirms that the observed sample is a dry gas of approximately 97% +/- 1% methane. Independent PVT laboratory analyses were performed on the samples. The laboratory analysis showed an average methane composition of all samples within 0.4% of ICE Core values, which is well within +/- 1% ICE Core uncertainty range. Demonstrated sensitivity for the ICE Core methane sensor was 0.003 g/cc as measured by the flat period around 23:00 as highlighted by the yellow rectangle in Fig. 8.

Field Test 2. A second field test was conducted with the same ICE Core module in the WFT configuration shown in Fig. 6b for different formation field approximately 2 months after Field Test 1. The measured pump rate (green, left axis) and WFT tool measured fluid density (blue, right axis) are shown in Fig. 9. Six samples were taken during this test, and they are easily identified by the characteristic signature short spikes in density as the sample chamber is over-pressurized starting at ~8:10. Looking at Fig. 9, we observe that there is a fast, initial density change as the water-filled tool clears to formation fluid. Thereafter, during active pumping periods, we see that fluid density gradually decreases from 0.27 g/cc to 0.22 g/cc as highlighted by the green arrows. This decrease is indicative of lower contamination levels.

WFT capacitance measurements were also made during Field Test 2, and they are shown along with the measured pump rate and WFT fluid density.
density in Fig. 10. Comparison of the fluid density and capacitance data shows an interesting dichotomy. From 7:30 to 8:45, the fluid density sensor indicates that the fluid is a gas while the capacitance sensor reading of 85 pf suggests that the fluid in the line is water. Between 8:45 and 9:00, the capacitance sensor reading falls from 85 pf to 20 pf, and then gradually decreases to 15 pf, which is indicative of gas, during the remainder of the pump down. Combining this, the data suggest that there is a water plug in the line preventing the formation gas fluid from reaching the sampling tanks, and that this water plug clears the capacitance sensor around 9:00.

The ICE Core sensor is located after the capacitance sensor and immediately before the sampling chamber, as shown in Fig. 4. The ICE Core methane concentration vs. time is shown in Fig. 11 along with the ICE Core-transmitted light signal. There are several observations to make regarding the data shown in Fig. 11.

During the period from 7:30 to 8:00, the methane concentration is shown in yellow and fluctuates greatly. During the same period, transmitted light signal is above zero, but relatively low. The high-frequency fluctuations and low transmitted light signals are characteristic of a relatively opaque but highly contaminated fluid such as mud. The data is shown in yellow as a caution to the observer that light levels are lower than normal and that the absolute readings may not be as reliable as that of the relative readings.

Around 8:15, we note that the transmitted light increases by about an order of magnitude and the methane spikes decrease in amplitude. This data suggests that the initial mud-containing fluid, which had cleared the WFT fluid density sensor around 6:00, is clearing the optical sensor about 90 minutes later. ICE Core-measured methane is still shown in yellow, once again as a caution in interpreting the absolute concentration levels while gleanin information from the relative concentration levels.

At 8:45, a very interesting feature is observed. The ICE Core methane concentration, now shown in green to indicate strong light signals and high-confidence data, decreases from ~0.2 to ~0.16 g/cc. Most importantly, this is the same period during which the capacitance sensor indicated movement of a water plug. Thus we see that the ICE Core methane data is unambiguously real, and that the water plug is clearing the line after 9:00. After 9:00, we see that the ICE Core methane concentration settles rapidly around 0.2 g/cc and, discounting the expected sampling-induced fluctuations, remains at this level for the remainder of the pump-down period. Occasional spikes suggest the presence of a few remaining mud flakes.

The ICE Core methane sensor indicates that the formation fluid contains a high-methane concentration. The calculated values for pure methane under the downhole temperature and pressure conditions are shown along with the ICE Core methane concentration and the WFT fluid density in Fig. 12. Looking at Fig. 12, we see that the ICE Core sensor-measured methane concentration is very close to the pure methane values indicating that the fluid is primarily methane gas. It is also striking to note that the total fluid densitometer data and the methane
concentration data approach the theoretical methane line. Taken together, these data are both consistent and suggest that the formation fluid is primarily methane gas with some unknown residual compounds.

The ICE Core-measured methane concentration for Field Test 2 is 0.200 +/-0.003 g/cc. Comparison with laboratory values for the samples cannot be made as the laboratory results are not yet completed. We do note that the demonstrated ICE Core methane sensitivity for this field test is 0.003 g/cc as measured by the flat period after 9:30. This value is essentially the same as was observed in Field Test 1.

Field Test 3. Field Test 3 was conducted about 90 days after Field Test 1 using the same ICE Core sensor placed in the WFT string as shown in Fig. 6c. In Field Test 3, two zones were investigated and four samples were taken from each zone.

The measured pump rate and WFT fluid density for both zones are shown in Fig. 13 for the entire pumpout. The four sampling points from the first zone are easily identified by the characteristic pump-rate fluctuations starting from 23:00. The four sampling points from the second zone are equally easy to identify starting around 1:30.

Looking at Fig. 13, we see that the two zones are substantially different from one another. In the first zone, we see a fluid density, which rapidly changes from an initial 1.05 g/cc water/mud mixture down to almost 0.2 g/cc indicative of gas. The fluid density of the second zone, in contrast, rapidly settles on a value of ~1.05 g/cc indicating that this zone is aqueous.

The ICE Core-measured methane concentration for the first zone in Field Test 3 is shown in Fig. 14a along with the WFT fluid density and calculated concentration values for pure methane. There are several observations to make from the data in Fig. 14a. First, we note once again the high-frequency ICE Core methane spikes between 21:45 and 22:45. These are similar to the spikes observed in the other field tests and are indicative of cleanup in a primarily methane gas fluid. Closer study of the spikes and the WFT fluid density fluctuations shows a very good correlation between the two especially observed in the features between 22:30 and 22:45.

Between 22:45 and the 23:00 (the 1st sample period), the high-frequency fluctuations stop and the ICE Core methane concentrations show a very interesting feature that gradually diminishes from ~0.175 g/cc to ~0.15 g/cc. This period of interest is highlighted in Fig. 14b and plotted with the data obtained from the WFT capacitance probe. It is clear in Fig. 14b that the methane concentration and capacitance probe are highly correlated. At 22:45, the capacitance probe reading increases substantially from 0.05 pf to 0.13 pf at the same time the methane concentration is decreasing. This suggests that the decrease in methane concentration is unambiguously real and directly caused the additional contaminant responsible for the increase in the capacitance probe reading. Both graphs then spike during the sampling period starting at 23:00 and ending shortly thereafter. Then the same pattern, albeit on a smaller and declining scale, is seen to repeat in between the next three sampling periods. The correlation between the capacitance probe and the ICE Core methane concentration readings once again indicates that the patterns observed in the ICE Core readings are real and unambiguous.

Fig. 14a also shows the theoretical methane concentration as the dashed red line. The ICE Core methane reading indicates that the formation fluid is primarily methane gas, but not exclusively pure methane. We also note the same cleanup pattern as Field Test 2 where an increasing methane concentration is indicative of less displacement from OBM in the vapor phase, and a decreasing density is indicative of less OBM contamination in the vapor phase. The WFT density of 0.198 g/cc and the methane concentration of 0.167 g/cc suggest that the flow line fluid was 84% methane.

The ICE Core methane concentration and WFT fluid density are shown for the second zone in Fig. 15a. The WFT density values of ~1.05 g/cc indicate that the fluid in this zone is...
Figure 14a. ICE Core-measured methane concentration and WFT fluid density for the first zone of Field Test 3.

Figure 14b. ICE Core methane concentration and WFT capacitance during the period of interest in the first zone for Field Test 3.

Figure 15a. ICE Core methane concentration and WFT density for the second zone of Field Test 3.

Figure 15b. 50X scale expansion of Fig. 11a showing ICE methane concentration and WFT fluid density for the second zone of Field Test 3.

primarily water. The ICE Core sensor measures a methane concentration that is very close to zero, as would be expected for an aqueous fluid. A 50X expansion of the ICE Core methane concentration is shown in Fig. 15b. There are two key features to note. First, we once again observe the high-frequency spikes associated with the clean-up process. More importantly, the average methane concentration is seen to be 0.0006 ± 0.0002 g/cc, which corresponds to a GWR value for methane of 0.96 Sm³/Sm³ ± 0.32 Sm³/Sm³.

Finally, we note that ICE Core methane measurements in Field Test 3 were made from a low trace level of 0.0006 g/cm to a very high 0.175 g/cc concentration all using the exact same ICE Core sensor and ICE Core module. This demonstrates not only the sensitivity of the ICE Core measurement, but also its dynamic range.

Conclusions

Downhole methane detection with the ICE Core sensor platform placed in the Integrated Characterization System has successfully demonstrated methane detection over two orders of magnitude in concentration, from trace concentrations in water to high concentrations in the gas phase in three field tests. The robustness and reliability of the electrical, mechanical, and optical systems was demonstrated in all three field tests. Good agreement between the ICE Core measurements and independent laboratory values for methane concentrations was observed to within a standard deviation of ± 0.02 g/cc. ICE Core sensor technology provides new and valuable downhole fluid chemistry information which, when combined with other fluid monitoring techniques such as capacitance and fluid density, enables new insights and methods for real-time downhole fluid analyses. Introducing a series of ICE Core sensors, individually characterized for accurately detecting several of the other most relevant downhole fluid components, both organic and inorganic, will make it possible to perform more precise characterization of formation fluids using downhole formation testing tools.
FIELD DEMONSTRATIONS OF ICE CORE TECHNOLOGY

Authors

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Christopher Jones joined Halliburton through Westport Technology in January 2001. Chris supervised geochemistry at a PVT laboratory where several of his accomplishments included the development of laser cuttings analysis techniques and wellsite mud gas isotope analysis by laser spectroscopy. As an exploration consultant, he developed statistical geochemistry reservoir compartmentalization studies based on chemometric techniques and optical-statistical commingled pay allocation techniques. In 2007, Chris joined the Testing and Sampling technology group at Halliburton. As a scientific advisor, he started the Halliburton Fluid ID group and subsequently became manager of the Testing and Sampling group. Chris also manages the Optical Identification Tool development for Wireline and LWD. He received his BS degree in chemistry from the University of South Carolina and completed an MS degree in physical/analytical chemistry at the University of Houston.

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References


Qualitative and Quantitative Information
NMR Logging Delivers for Characterization of Unconventional Shale Plays:
Case Studies

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Abstract
The presence of organic pores in black shales posts new challenges for many logging tools and corresponding interpretation techniques. For nuclear magnetic resonance (NMR) logging, it also faces measurement difficulties attributed to the fast relaxation time and low porosity associated with the proton NMR signals in organic shales. Despite these challenges, NMR logging has been proven valuable for porosity, TOC, and hydrocarbon identification for organic-shale reservoir characterization. This paper begins with a brief description of the theoretical expectations of NMR logging responses in organic shale, followed by a case study including 19 wells belonging to the Eagle Ford shale formation. The study investigates the different NMR logging responses between organic-rich shale reservoirs and conventional reservoirs, and the difference between the organic-rich lower Eagle Ford vs. organic-poor upper Eagle Ford shales. The study covers wells that are in gas, gas condensate, and oil windows. In some wells studied, multiple passes with different NMR data activation methods were available. This paper mainly presents statistically significant results and discussions; individual well results are used only for the purpose of illustrating trends and features common to most of the wells studied.

Introduction
Despite the unfavorable poor signal-to-noise ratio and rapid decay of NMR signal in organic-rich shales, the value of NMR logging for petrophysical analysis and hydrocarbon evaluation of gas and oil shales has been recognized in several aspects, such as for the estimation of porosity and porosity distribution (Ramakrishna et al, 2010; Ramirez et al, 2011), TOC (Jacobi, et al, 2008), and the potential for distinguishing water from organic matter. On the contrary, the nanometer pore scale and the fluid in organic pores resulted in different NMR relaxation and diffusion mechanisms than for conventional reservoir rocks. Consequently, some NMR data interpretation models that work for conventional reservoirs might require modification when interpreting NMR measurements in organic-rich shales.

Several attempts were made recently to study the mechanisms of NMR response in organic-rich shales. Chen et al (2012) reports a laboratory NMR investigation of capillary condensation of hexane vapor in smectite clays. Their study demonstrates that the NMR T1 relaxation time of the hexane is in the range that can be observed by the current NMR logging tools. A subsequent theoretical paper (Chen, 2013) suggests that the capillary condensation can occur in typical unconventional reservoir conditions and the hydrocarbon storage can be significantly higher than that predicted by the Langmuir model. If verified, NMR could be of unrivaled importance for predicting the hydrocarbon storage in black shales.

Kausik, et al (2012) examines the surface relaxation and restricted diffusion effects of gas in kerogen nanopores. Their laboratory NMR measurements of brine and methane saturated Haynesville shale core plugs demonstrate that both the adsorbed (~10 ms) and free gas are observable using NMR. The short relaxation time of gas in kerogen nanopores is interpreted to be caused by strong surface relaxation.

Sigal et al (2010) use laboratory NMR T1 and T2 measurements on methane-filled siliceous shale samples to investigate the difference in T1/T2 ratio of brine-saturated mature organic shales compared to oil-saturated organic shales. Their results indicate that the T1/T2 ratio for brine-saturated samples are consistently lower than that for oil-saturated samples, suggesting it might be possible to use the T1/T2 ratio derived from NMR logging data to estimate the hydrocarbon content of organic shales.

In this paper, the effects of nano-pore and organic pore on NMR responses are briefly discussed. Eagle Ford shale data is primarily used to demonstrate the theoretical expectations. Several practical aspects of NMR data processing, including porosity quantification, the T1/T2 ratio, geometric means and patterns and the relaxation time distributions, and correlating NMR response with the kerogen and fluid hydrocarbon content are also discussed.

The Eagle Ford (Fig. 1) is a carbonate-rich, hydrocarbon-producing shale formation. The GOR content of the formation has a good correspondence with the formation depth. The south part of Eagle Ford is primarily deep, dry-gas bearing; the middle Eagle Ford belt produces wet-gas/gas condensates; and, the north part of Eagle Ford is primarily shallow and oil bearing.

This multiwell study was chosen primarily using Eagle Ford shale data because it covers all hydrocarbon types (i.e., oil, gas-condensates, and dry-gas). Its relatively consistent mineralogy and lithology (i.e., carbonate-rich) over the different types of hydrocarbon-bearing sections reduces the complexity when comparing the NMR logging responses to the hydrocarbon types in the shale formation.

The present study aims to discover the common trend of NMR signature in oil and gas windows. It also investigates the indicators for discerning organic-rich shales from inorganic shales. Additionally, the quantitative aspects of the commonly used NMR measurements and derived quantities, such as T1 and T2 distributions, and the ratio between the two parameters, and their robustness for using as a kerogen or hydrocarbon indicator, are investigated based on the realistic signal-to-noise (SNR) common to NMR logging. For wells where mineralogy logs or laboratory data are available, the NMR results are compared to the
kerogen and hydrocarbon derived from non-NMR logs. Some trends were observed that are consistent with previous laboratory NMR studies, along with others that might be not observed from core data.

Mechanisms of NMR Responses Unique to Organic Shales

In terms of NMR interpretation, organic shales have two unique features that differ from conventional reservoir formations. The first is that the typical pore size in shale formations are several orders of magnitude smaller than that of typical sandstone or carbonates, down to the nm range. The second is the existence of organic pores—the pores within the kerogen as well as intercrystalline pores—and that the organic pores are likely hydrophobic.

The nanometer size enhances surface relaxation, even if the surface relaxivity is the same. The surface relaxation rate is

$$T^{-1} \propto \rho_{1,2} \cdot \frac{S}{V} \sim r^{-1}$$  \hspace{1cm} (1)$$

where $\rho_{1,2}$ are the surface relaxivity corresponding to the longitudinal relaxation time $T_1$ and the transverse relaxation time $T_2$; the $S$ and $V$ are the pore surface area and pore volume, respectively, and $r$ the characteristic pore size.

The nm pore size also affects the diffusion. Although free gas diffusivity is higher than that of both oil and water, the geometric confinement to the molecular diffusion in nanopores effectively "slows" down the diffusional process. As a result, the apparent gas diffusivity in nanopores is expected no larger than that of apparent diffusivity of oil.

Another possible mechanism of hydrocarbon gas molecules in nm scale pores is the capillary condensation effect, where vapor phase in small pores form multilayer adsorption to the point at which pore spaces become filled with condensed liquid from the vapor phase, which can occur below the saturation vapor pressure, $P_{sat}$, of the pure liquid. The condensation phase has a higher density than the dry-gas phase and a lower diffusivity. As a result, the capillary condensation of the gas phase results in a reduced diffusivity, which further masks the diffusion-based technique to discern dry-gas-bearing shales from condensate-bearing shales.

Thus, it can be seen that the capillary condensation and the restricted diffusion act in unison to smear the diffusivity difference between gas and liquid phase hydrocarbon in organic shales. NMR senses restricted diffusion differently using different TE in a CPMG echo train measurement. Fig. 2 illustrates the apparent diffusivity as a function of pore size for the liquid and gas hydrocarbon phases. The free diffusivity values are modeled as $10^{-9}$ m$^2$/s for methane gas and $10^{-7}$ m$^2$/s for oil, respectively. In simulating the NMR sensed restricted diffusion, the interecho time (TE) of a typical logging tool, 0.4 ms and 1.2 ms and a magnetic field gradient of 15 G/cm are used. The results are calculated using the same approximation as that used by Grebenkov (2007).
Oil-wetting or mixed-wetting characteristics reduce the hydrocarbon relaxation times in organic pores significantly, so the conventional interpretation of relaxation time distribution, namely the light hydrocarbon signal appearing on the right of the distribution, is not expected to be observed hydrocarbon in organic pores.

Since
\[
\frac{1}{T_1} = \frac{1}{T_{1b}} + \rho_1 \frac{S}{V} \tag{2}
\]
and
\[
\frac{1}{T_{2\text{app}}} = \frac{1}{T_{2b}} + \rho_2 \frac{S}{V} + \frac{\gamma^2 \rho_2 G_2^2 T E}{12} \tag{3}
\]
the ratio is approximated by
\[
\frac{T_1}{T_{2\text{app}}} \approx \frac{\rho_2}{\rho_1} + \frac{\gamma^2 \rho_2 G_2^2 T E}{12} \frac{S}{V} \tag{4}
\]
where the first term is of the order of unity and the second term, according to Fig. 2, is greater than \(10^{-5}\) for sub-micron pores. Thus, it can be expected that
\[
\frac{T_1}{T_{2\text{app}}} \approx \frac{\rho_2}{\rho_1} \tag{5}
\]
depends only on the surface relaxivity and not the diffusivity for the nm pores.

Figure 3 shows two examples of the Eagle Ford shale gas window (left) and oil window (right) \(T_1\) vs \(T_{2\text{app}}\) maps. The parallel slant lines are the constant \(T_1/T_{2\text{app}}\) values. It can be seen that, for both oil-bearing and gas-bearing Eagle Ford shale, the \(T_1/T_{2\text{app}}\) is only slightly above 1, which is consistent to the expectation of Eq. (5).

Log Results
Porosity
The magnitude of NMR signal is proportional to the number of NMR-measurable protons within the sensitive volume. The “NMR-measurable” term is dependent on the minimum TE a tool can reach to acquire a CPMG echo train.

The definition of organic shale porosity might still be somewhat debatable. Nevertheless, here, NMR apparent porosity in organic shale is defined as the measurable NMR signal amplitude divided by the NMR amplitude of water signal in the same sensitive volume, measured at a given interecho time TE.

Even though it is desirable that TE be as small as possible to increase the measurable range of the NMR signal, it was found that practically, the current logging tool’s minimum TE is adequate to obtain porosity that are comparable to core porosity measurements.

Fig. 4 shows the occurrence of normalized porosity histogram of conventional core and NMR logging slightly larger than the core porosity. Clearly, there is no loss of porosity attributed to the finite TE for the Eagle Ford.

NMR log porosity can be derived from either \(T_1\) or \(T_2\) logs, or from 2D inversion results. Shown in Fig. 5 is an example log from the Woodford; the porosity was derived from the simultaneous inversion of both \(T_1\) and \(T_2\), which obtains single

Figure 3. Examples of NMR \(T_1\) vs. \(T_{2\text{app}}\) plots of typical gas-bearing (left) and oil-bearing (right) Eagle Ford shales. As expected, no appreciable amount signal is shown in the theoretical locations of conventional gas (intersect of red dash lines) or light oil (green line).

Figure 4. Apparent porosity comparison between core and MRIL log-derived porosities for multiple wells in the organic-rich interval of Eagle Ford formation.

Figure 4. Apparent porosity comparison between core and MRIL log-derived porosities for multiple wells in the organic-rich interval of Eagle Ford formation.

derived porosity from 24 MRIL® logs and 66 core measurements in the organic-rich interval of lower Eagle Ford shale formation. The NMR logging data were acquired with a minimum TE of 0.6 ms. Even with this TE value, the apparent porosity from NMR logs is very consistent to the core porosity. In fact, overall, the NMR log-derived porosity appears porosity value, instead of two different values. The neutron (blue) and density (red) porosities on the left track are significantly larger than the NMR \(T_1\) porosity (black). The red dots shown on the right side track is core porosity (CPOR). Clearly, it can be seen that NMR-derived porosity matches the core porosity very well.
The good match between NMR log porosity and core porosity can be well understood by examining the $T_1$ and $T_2$ distribution patterns and the mineralogy of the organic-rich Eagle Ford shale, inorganic, clay-rich Del Rio shale, and the organic-poor Pearsall shale. In Figure 6, from left to right, the first and second tracks are $T_1$ and $T_2$ distributions, respectively. The third track shows the volumetric fraction of mineralogy where the pink color represents kerogen. It can be seen that the relaxation time distributions are characterized with a broader distribution within the range of a few ms to less than 100 ms for organic rich, limestone-mud-rich Eagle Ford shale. This is quite different from the narrow, short $T_1$ and $T_2$ distribution in the inorganic, clay-rich Del Rio shale, and is also different from organic-poor Pearsall shale. The absence of very short decay components observed in the Eagle Ford explains why porosity undercall is unlikely to occur.

NMR logs often show characteristic differences in relaxation time distribution patterns. Shown in Figure 6 are the $T_1$ and $T_2$ logs (tracks 1 and 2 from left) of two wells in the Eagle Ford section. The shaded black area of the third track is the volume fraction of kerogen from which one can determine the boundary between the upper and lower Eagle Ford intervals. The light green shaded area represent hydrocarbon. The kerogen and hydrocarbon (oil and/or gas) volumes are outputs from GEM-based interpretation utilizing a probabilistic error minimization program. The integrated interpretation approach usually includes inputs from neutron, density, GEM, and resistivity data but not NMR logging data.

Similar to what is shown in Figure 6, the $T_1$ and $T_2$ distributions in Figure 8 are considerably broader than that of a typical clay-rich shale, such as the Del Rio. The lower-kerogen-bearing upper Eagle Ford has an even broader $T_1$ and $T_2$ distribution.
compared to the kerogen-rich lower Eagle Ford section. In the upper section, being kerogen poor, the proton NMR signal contribution can be viewed as largely from the non-organic pores; thus, the broader distribution is the result of pore-size effect. On the contrary, for the kerogen-rich lower Eagle Ford section, a significant part of the protons are from hydrocarbons in organic pores where they might be less affected by the pore sizes. Note that the clay volume in the upper Eagle Ford of Well 1 (Fig. 8) is lower than that of the lower section, while for Well 2, it is just the opposite. Yet, both wells show similar trend of $T_1$ and $T_2$ spectra shift. This suggests that the shift is more likely related to the organic content than to the clay content.

It is noted that the $T_1$ and $T_2$ range of the organic-rich lower Eagle Ford is consistent to that reported in the laboratory-controlled core studies (Chen et al., 2012; Sigal et al., 2011). The difference between the upper and lower Eagle Ford suggests that the hydrocarbon signal in the organic pores can be observed (or measured) using the current NMR logging tools.

It is worthy to point out that, in some cases, the difference of $T_1$ and $T_2$ distributions between the upper and lower Eagle Ford sections are not as obvious as the one observed in Fig. 8. This could be attributed to the distribution of the kerogen in the shale and possibly also to the hydrocarbon type, i.e., gas vs. oil. More gas wells need to be studied to draw a more definite conclusion.

$T_{1GM}$, $T_{2GM}$ and $T_{1GM}/T_{2GM}$ Ratio

The geometric means of the relaxation times, $T_{1GM}$ and $T_{2GM}$, usually shift left from the upper to the lower Eagle Ford, as can be seen from the red and blue curves in Fig. 9 for two oil-window wells with different GOR. It is noticed that the $T_{2GM}$ shift at the transition is not as obvious as the $T_{1GM}$ shift, which is common to most wells. A more unambiguous shift is often observed by plotting the $T_{1GM}/T_{2GM}$ (Track 1) and $T_{1GM}/T_{2GM}$ ratio (Track 2) of one well in the oil window. The left shift of $T_{1GM}$ / $T_{2GM}$ is more clearly observed than the $T_{1GM}$ or $T_{2GM}$. Because of the $T_{1GM}$ / $T_{2GM}$ contrast between the upper and lower sections, the $T_{2GM}$ contrast is greater than the $T_{1GM}$ contrast between the two sections. This can be readily observed when plotting the data in histograms (Fig. 11).
Figure 10. Left shift of $T_{1GM}$ and $T_{2GM}$ is observed when transiting from the upper to the lower Eagle Ford. The $T_{1GM}/T_{2GM}$ ratio (right track) appears to be a better indicator of where the transition occurs.

Kerogen and Hydrocarbon Correlation with $T_{1GM}$, $T_{2GM}$, and $T_{1GM}/T_{2GM}$

In the previous sections, it was shown that the $T_{1GM}$ or $T_{2GM}$ or $T_{1GM}/T_{2GM}$ ratio values vary from the upper to lower Eagle Ford shales. In this section, we demonstrate that, by scaling $T_{1GM}$ or $T_{2GM}$ with the kerogen and hydrocarbon quantities

depths is approximately 80% from integrated interpretation. (The integrated interpretation method does not include the use of the NMR fluid typing method.) These gas saturation values are reported on the individual maps. Among the five depths, only one appears to have a weak signal, shown at the top-center of the map where the conventional reservoir free gas is expected. This one isolated case could be caused by the gas signal seeping through large fractures, or that the formation rock has large (i.e., above 1 μm approximately, as indicated by Fig. 2) pores to overcome the restricted diffusion effects. Thus, the observation of the gas signal would likely be the indication of high-permeability shale in the corresponding depth of the reservoir.

Kerogen and Hydrocarbon Correlation with $T_{1GM}$, $T_{2GM}$, and $T_{1GM}/T_{2GM}$

In the previous sections, it was shown that the $T_{1GM}$ or $T_{2GM}$ or $T_{1GM}/T_{2GM}$ ratio values vary from the upper to lower Eagle Ford shales. In this section, we demonstrate that, by scaling $T_{1GM}$ or $T_{2GM}$ with the kerogen and hydrocarbon quantities, one can correlate these NMR quantities

Figure 9. $T_1$ and $T_2$ distributions of two wells in oil-bearing Eagle Ford shales having different GOR. The similar trend of relaxation time distribution patterns are found in these two wells as that shown in Fig. 8. The $T_{1GM}$ (Tracks 2 and 4) and $T_{2GM}$ (Tracks 1 and 3) exhibit a left-shift from upper to lower Eagle Ford.

Figure 12 shows the mean values of the $T_{1GM}/T_{2GM}$ ratios of the upper and lower Eagle Ford shales, respectively, for all logging passes in all 19 wells studied. The blue dots are the $T_{1GM}/T_{2GM}$ derived from the lower Eagle Ford, and the red dots are derived from the upper Eagle Ford. It can be observed that, for all cases, the organic-rich lower Eagle Ford corresponds to a lower $T_{1GM}/T_{2GM}$ value of about 2.5, while the upper Eagle Ford corresponds to a higher value of about 3.5. Considering these are derived from a large number of data, the difference is quite reliable. It is also noticed that, for the deeper wells in the gas window, the $T_{1GM}/T_{2GM}$ values between the upper and the lower Eagle Ford are not as significant as that in the shallower oil and condensates wells.

The logging data derived $T_{1GM}/T_{2GM}$ values observed in these wells appear to be in close proximity, though slightly lower, of the average values reported by Ozen and Sigal (2013) in their studies of crude oil saturated grounded-up shale-gas-reservoir samples. The important point is that this study indicates that NMR $T_{1GM}$, $T_{2GM}$ and $T_{1GM}/T_{2GM}$ logs have a good correlation with kerogen and hydrocarbon in the shale reservoirs.

Hydrocarbon Identification with 1D Spectrum or 2DFC

In the previous section that describes the mechanism of relaxation times in organic-rich shales, it was stated that hydrocarbons in organic-rich shale are not expected to appear in the same region of either the relaxation time spectrum or the 2D fluid characterization (2DFC) map, as expected for conventional reservoirs. In Figures 6, 8, and 9, the absence of the long relaxation time signal in the $T_1$ and $T_2$ distribution logs for the organic-rich sections was observed.

To further demonstrate that Eq. (5) holds true, in Fig. 13, the 2DFC - $T_1$ vs. $T_{2GM}$ maps corresponding to a different depth of an Eagle Ford shale-gas well are plotted. The gas saturation at these
with kerogen or kerogen + hydrocarbon volumes, derived from integrated interpretation independent of NMR data. Plotted in Fig. 14 are four tracks; the shaded blue areas represent the kerogen (Tracks 1 and 3) or kerogen + hydrocarbon volume (or and/or gas, Tracks 2 and 4) derived from integrated petrophysical models. The red curves are derived from scaled NMR data.

Tracks 1 and 2 include NMR $T_{1GM}$ results. The red curve in the first track is $(21 - T_{1GM}) / 100$, where the value of 21 is the average $T_{1GM}$ corresponding to the minimal kerogen or kerogen + hydrocarbon volume. Similarly, in the second track, $(21 - T_{1GM}) / 200$ is plotted.

Tracks 3 and 4 include NMR $T_{2GM}$ results. The red curve in the third track is $(4.5 - T_{2GM}) / 20$, where the value of 4.5 is chosen to take into account the average $T_{2GM}$ corresponding to the minimal kerogen + hydrocarbon volume in the upper Eagle Ford. Similarly, in the fourth track, $(4.5 - T_{2GM}) / 100$, where the value of 4.5 is chosen to take into account the average $T_{2GM}$ corresponding to the minimal kerogen volume in the upper Eagle Ford. Comparing these two parameters, it appears that the use of the $T_{1GM} / T_{2GM}$ ratio is less affected by noise.

Without changing the scaling factor, another well data is plotted in Fig. 15. Similar correlation can be observed. The results shown in Figs. 14 and 15 suggest that an empirical correlation between these NMR parameters and the kerogen or kerogen + hydrocarbon volume could be found. In these two figures and other wells studied, it is found that these two parameters correlate with kerogen alone better than with kerogen + hydrocarbon. Further investigation is required to obtain a more robust form of the correlation for all wells. At minimum, the constants in the scaling process might require adjustment in accordance with the corresponding depths in the upper Eagle Ford where the kerogen reading is approximated zero. Also, the effect of clay content and hydrocarbon types (gas, condensates, or oil) on the NMR relaxation times and $T_{1GM} / T_{2GM}$ might need to be included to improve the correlation. It is also worthy to point out that the $T_{1GM}$ and $T_{2GM}$ can be affected by many factors. Therefore, this approach should not be extended to other formations without thorough investigation.

Discussion

The current default practice of choosing the $T_{1GM}$ values for the clay bound water and the capillary bound water to be twice that of the corresponding $T_{2GM}$ values. As can be observed in Fig. 14, the mean $T_{1GM} / T_{2GM}$ is greater than 2 for both the upper and lower Eagle Ford; the choice of the factor of 2 between the two cutoffs could risk a bias. For the lower Eagle Ford, the bias is expected to be small.

While, for the upper Eagle Ford, because the average ratio value is larger than 3, the bias could also increase.

Fig. 16 shows the summation of partial porosities up to the $T_{2GM} = 10$ ms and $T_{2GM} = 20$ ms, which are commonly used as defaults for real-time log plots. The bias is consistent to the fact that the actual $T_{2GM}$ is greater than 3.

To reduce the potential bias, in absence of calibration, it is recommended that, for the lower Eagle Ford, a scaling factor of 2.5 is used; while, for the upper Eagle Ford, the factor of 3.5 is better. This recommendation is based on the observation shown in Fig. 16, and the fact that most of the signals relax rapidly; thus, the ratio of the entire spectrum and the partial spectrum is similar.

Furthermore, it is worthwhile to point out that it is unlikely that the volume derived from the summation of partial porosities up to the cutoff values actually represent bound water in organic-rich shales; instead, the significant portion of that signal might come from organic matters (kerogen and hydrocarbon). Therefore, using the cutoff value might be more reasonable to correlate organic content in these shales, rather than to quantify bound water.
Figure 13. 2DFC - $T_1$ and $T_{2\text{app}}$ maps corresponding to different depths of an Eagle Ford shale gas well. The gas saturation at these depths is known to be approximately 80% from integrated interpretation, excluding the use of NMR fluid typing methods. The gas saturation values are reported next to the individual maps. Among the five depths, only one appears to have a weak signal shown at the top-center of the map where conventional reservoir free gas is expected.

Figure 14. $T_{1\text{GM}}$ and the ratio of $T_{1\text{GM}}/T_{2\text{GM}}$ scaled to the kerogen and kerogen+oil volumes for Well D. See text for the details of the scaling parameters.

Figure 15. $T_{1\text{GM}}$ and the ratio of $T_{1\text{GM}}/T_{2\text{GM}}$ scaled to the kerogen and kerogen+oil volumes for Well E. See text for the details of the scaling parameters.

Figure 16. Illustration of using the default factor of 2 between bound water $T_1$ and $T_2$ cutoff values. The three plots are shown using the data from three wells.

Summaries and Conclusions
Logging data results were presented that support the theoretical expectation of NMR in sub-micron-sized organic pores. The 19-well Eagle Ford case studies demonstrated that NMR logging is valuable to organic shale formation evaluation in many ways.

- The TE of the current NMR logging is adequate for detecting all porosities for Eagle Ford shales. No porosity undercall is observed compared to core-derived porosity.
- The $T_1$ and $T_2$ distribution patterns are significantly different for organic-rich Eagle Ford vs. typical inorganic, clay-rich shales.
- $T_1$ and $T_2$ distribution patterns, $T_{1\text{GM}}$ (or $T_{2\text{GM}}$) and $T_{1\text{GM}}/T_{2\text{GM}}$ ratio are noticeably different for the organic-rich lower Eagle Ford and the organic-poor upper Eagle Ford. The difference appears correlating to kerogen volume or kerogen + hydrocarbon volume.
- The $T_{1\text{GM}}/T_{2\text{GM}}$ ratio difference is more significant in oil and condensate windows than the gas windows.
- The combination of restricted diffusion in sub-micron pore sizes and the adsorption mechanisms in organic pores smears the apparent diffusivity difference between hydrocarbon types. Thus, the ratio between $T_1$ and apparent $T_2$ is dominantly the surface relaxivity ratio, which is consistent with log observations.
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PNL Application in CO₂ and Oil Saturation in CO₂ Flooding Fields

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Abstract
CO₂ flooding was applied to a mature field to increase oil recovery. Accurately determining residual oil saturation (ROS) is very important for evaluating project economics. In addition, constant surveillance of the CO₂ migration during flooding is critical so that the injection pattern can be modified to optimize oil sweeping efficiency. Usually, wells available for logging are already cased and cemented. Thus, formation evaluation must be performed with logging tools suitable for cased-cemented wells. ROS determination using carbon oxygen (C/O) data from a pulsed neutron log (PNL) is proven technology for this situation. In mature fields, the average oil saturation is usually low (below 35%), which causes the C/O signal from the oil to be low. The uncertainty of the measurement comes from two sources: there is a statistical error related to the radioactive measurement, and a systematic error from the methods used (depth alignment, petrophysics model, etc.). Both statistical and systematic errors can be reduced by using fewer logging passes at very slow logging speeds and a sound interpretation model. When CO₂ is in the field, the CO₂ phase can be determined by using a Thermal Multigate Decay 3-Detector (TMD-3D™) log, which is based on the hydrogen index response in a time window in the long detector decay response. This is different from a sigma log and is not limited by the sigma contrast between oil, saline water, and gas. This method can be used with a C/O log to interpret three-phase saturations. Case studies from a selected well are presented to demonstrate the feasibility of this technology. A petrophysics model and operational best practices are also discussed.

Introduction
A mature Permian carbonate reservoir in west Texas was under nitrogen and steam injection before being switched to CO₂ recently. Production history has proved that CO₂ is a more effective method for mobilizing residual oil. Years of gas injection and production created a gas cap above the oil column, with significant remaining oil trapped in the gas cap. The reservoir is shallow with low temperature (84°F) and low pressure (~640 psi). The formation is heavily fractured and vuggy with porosity ranging from 10 - 25 porosity units. Dolomite and limestone are the main lithology. The water salinity in the reservoir varies due to water injection being used for pressure maintenance. Due to the high H₂S risk, field operation safety procedure requires all wells to have tubing. Unfortunately, most tubing is too small to run logging tools through. To pull the tubing, the well has to been killed by fluid, which will invade the near-wellbore zones. This condition is challenging for conventional openhole evaluation when measuring three-phase fluid saturation. However, in cased holes the tubing can be pulled without borehole fluid invading the near-wellbore zones.

Methodology
The conventional resistivity-based saturation measurement is sensitive to the volume of water and to the geometrical distribution of water in the pore space due to the pore structure or pore surface wettability. This method is also sensitive to water salinity. Thus, deriving water saturation is more complex in carbonates because it is more difficult to correctly estimate formation water resistivity Rw, the formation factor M, and the saturation exponent N for Archie’s equation. M and N may also depend on porosity when porosity is low. Fig. 1 shows how electrical current flows through the rock.

The C/O method for deriving oil saturation is only volumetric dependent. Geometrical fluid distribution does not affect this method. The RMT™ (Reservoir Monitor Tool) device measures total amount of C/O in the rock and in the fluid. Carbonates contain carbon and oxygen in the matrix. The matrix of kerogen and coal also contain carbon. Fluids that contain carbon are oil, hydrocarbon gas, and CO₂ (carbon dioxide). For a conventional oil reservoir the amount of oil is proportional to the amount of organic carbon.

The gas phase can be recognized by a lower hydrogen index as compared to a pore filled with water or liquid.

The combination of two logging technologies, a C/O log from an RMT and a gas saturation log from a TMD-3D tool, lets us accurately measure three-phase saturation without the limitation of the conventional resistivity-based method. Fig. 2 shows the work flow for this evaluation method.
1. TMD-3D tool runs one pass with logging speed set at 10 ft/min in Sigma mode. The result is processed using the GasSat™ model.
2. The RMT tool runs two passes in C/O mode and one pass in Sigma mode:
   a. Logged two passes at 1 ft/min in C/O mode and one pass Sigma mode at 10 ft/min.
   b. Result is processed using CarbOxsat™ model to derive oil saturation with independent of water salinity input.
   c. Corrected the oil saturation for the C/O contribution from CO₂ gas.

CO₂ Log Basics: Data acquisition was done using e-line, since the well was shallow enough and vertical. Quality of the data can be checked in

Figure 1. Electrical current path in the rock (tortuosity).

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real time using a tool measurement indicator. For example, the tool operator (Field Engineer) can monitor some indicator curve during logging such as generator voltage, internal tool temperature, total counts, etc. The critical quality factor is the energy spectrum recorded in the near and far detector.

The Pulsed Neutron Log measures gamma rays emitted from the atom nucleus activated by high-energy neutron bombardment. Each element has a characteristic gamma ray energy spectrum. The gamma detector converts the energy to electrical pulses and sorts them by energy level and time sequences (length of decay).

down the neutron velocity. The gamma energy emitted during this reaction is collected as part of the inelastic gamma ray spectrum. Later after the neutron has slowed down to the level of ambient temperature energy, the small nucleus atom (hydrogen) will effectively capture the low energy neutron. The gamma ray emitted from this process is called the capture gamma ray spectrum.

The example spectrum processing results in Figs. 3 and 4 shows the curve fitting method used to extract elemental yields from the gamma ray energy spectrum. The shop calibration value from the calibration tank is used to adjust the amplitude of the energy spectrum from the inelastic and capture gamma spectra. Then elemental yields are derived from both energy spectra. Fig. 3 shows the derived elemental yields for H, Fe, Si, Ca, Cl, K, and S from curve fitting for the far capture spectrum. Fig. 4 shows the inelastic spectrum and the fitted elemental finger prints for O, C, Ca, Si, and Fe.

Sigma Log Basics. The decay spectrum data is processed using a dual decay model (Fig. 5) to compute sigma borehole (SGBN, SGBF) and sigma formation (SGFN, SGFF) values from the near and far detectors. The sigma intrinsic (SGIN) is derived through the environmental and diffusion corrections from those four sigma measurements. To check the quality of the sigma output, the fit error is computed from the difference between actual decay data and the dual exponent decay model. Fig. 5 shows the far detector decay results with a curve fitted for formation decay.

The sigma for this tool is defined as:

\[
\Sigma = \frac{4550}{\tau} \text{ in capture units} \quad (1)
\]

where \( \tau \) is the inverse of the decay slope or \( \tan \alpha \).

Fig. 5 is an example of data decay from the far detector where the derived sigma formation (SGFF) is equal to 30 capture units.

The secondary output from the sigma mode pass is a ratio of total counts. The ratio of total counts from the inelastic window from the near detector to inelastic counts from the far detector is RIN.

![Figure 2. Work flow of evaluation method.](image)

![Figure 3. Capture spectrum and the fitted elemental finger prints for H, Fe, Si, Ca, and Cl.](image)
The other outputs are the ratios of total counts inelastic to total counts capture for the near and far detectors (RICN and RICF, respectively). Those are related to the bulk density measurement similar to the open log measurement.

The ratio of total counts inelastic and capture from near and far detector is RNF. The total counts capture ratio from far to near detectors is RCAP. Both are related to neutron porosity.

The sigma log is mainly controlled by water salinity, since chloride is very effective in slowing down and capturing the neutron. Hence this type of pulsed neutron measurement produces three types of output, which are similar to resistivity, bulk density, and neutron porosity.

Raw Data Extraction. The first data quality checks are made during data acquisition and before doing any interpretation. Next perform the energy calibration. This means to align the array value based on the energy value. The calibration is a two-point calibration (the low and high point) and linearity is controlled by the oxygen peak. Extract the elemental yields by using windows-type processing for specific content.

The sigma is derived from the RMT data run in sigma mode and then by using dual decay model curve fitting to the far and near decay data. The first decay output is sigma borehole. The second decay output is sigma formation.

The best borehole environment for running the RMT tool is low salinity or fresh water. High salinity water absorbs a lot of neutrons and thus fewer neutrons go into the formation. The output gamma ray counts in the spectrum and the decay are low and the fit error becomes large due to high statistics.

The shale effect causes the sigma output to be higher than it would be in a clean formation. Lower porosity and hydrocarbon in the pores causes the sigma reading to be low. The capture and inelastic spectra for the near and far detectors are shown in Figs. 6a and 6b.

The primary output from the C/O mode and the Sigma mode are plotted in Figs. 7a and 7b.

Environmental Correction. Environmental corrections are used to eliminate the contributing effects of the borehole environment to the output formation properties we measured. This includes borehole fluid, casing size, and cement. In the TRAC LAB at Halliburton this tool has characterized different lithologies such as sandstone and limestone after correcting for casing diameter, borehole fluid, and salinity (Jacobsen, et al. 1998). The Monte Carlo simulation model is also used as benchmark.

Environmental corrections are very critical for correcting survey data from the well during flowing/production since the oil signal from the bore is very large compared to the signal from the oil in the formation. The signal from the oil in the borehole is larger in volume and is also closer to the detector. Thus, if the borehole is filled with oil, the oil signal from the formation is masked.

The sigma correction is predominantly a function of fluid salinity in the borehole. The sigma value for NaCl is 750 capture units, which is much higher than the sigma of oil, water, or the rock formation. A small amount of NaCl (sodium chloride) causes the sigma reading to be too high. Fig. 8 shows the results of the environmental correction.

CO Analysis. In the C/O analysis using the model from Jacobson et al. (1998), the oil saturation is a function of the C/O, LIRI, TPOR, and shale volume. The basic CO model equation:

\[ S_{OC} = 1.59 \times \left[ 1 - 0.37 \frac{\phi \text{B}}{\phi_1} \right] \times \left[ 1 + \frac{0.33 \phi \text{B}}{\Delta \text{CO}} \right]^{-1} \quad (2) \]

where: \( \Delta \text{CO} = \text{COIR} - 0.21 \times \text{LIRI} + 0.088 \times \phi_1 - 0.16 \) \quad (3)
The formation can be divided into two zones: the upper zone is predominantly limestone and the lower zone is predominantly dolomite. The model is represented graphically in Fig. 9.

On the left y-axis there are two vertex points; one is for dolomite and one is for limestone. On the right y-axis, the upper point is for oil and the lower point is for water. All the points are inside the envelope. In Fig. 9, the interpretation fan charts for dolomite and limestone are similar to but not identical. A customized fan chart is created for each depth based on the relative composition of limestone and dolomite. Fig. 10 shows the derived oil saturation.

Gas Saturation Analysis. The TMD-3D Pulsed Neutron tool was developed from the previous TMD-L tool by adding the third detector as a long detector. The third detector functions mainly to quantify gas saturation (Weijun Guo et al., 2010) using the tool response called SATG (Weijun Guo et al. 2012). This technique is less dependent on lithology and water salinity. SATG is defined as:

$$ SATG = \frac{\text{Inelastic counts}}{\text{Slow capture counts}} $$ (4)

The total inelastic count is the total count of gamma rays from time zero to 90 microseconds. The slow capture is the total count of the decay from 600 microseconds to 1250 microseconds.

The slow capture window was set up to avoid the borehole signal and capture the signal from formation decay.

The gas saturation is a function of SATG and porosity, and the envelope has two boundaries. The lower limit boundary is for gas and the upper limit boundary is for liquid. The liquid could be water, oil, or mixed oil and water. Water salinity has significant effects when it is higher than 150 kppm.
The CarbOxsat model shown in Fig. 10 needs C/O corrections for the contributions from methane and carbon dioxide.

The oil saturation correction due to the carbon signal from the CH4 and CO2 gases as a function of gas volume is:

$$SOT_{cor} = 1.59 \times \left[ 1 - 0.37 f_T \right] f_T \times \left[ 1 + 0.33 \rho_{oil} C F \times D CO \right]^{-1} \quad (5)$$

Where correction factor

$$CF = 1 - \frac{V_{gas}}{\rho_{oil}} \times \frac{\rho_{oil}}{P_{oil}} \quad (6)$$

The points outside the envelope are mostly come from the shale section data. This is because the neutron absorption in the shale is higher than in the water-filled sand. When formation water salinity is very high, the SATG value for shale will be lower than the upper water line. Based on the SATG envelope in Fig. 12, the results of the gas saturation computed for every depth level are shown in Fig. 13.

**Oil Saturation Corrections.** The gas saturation shown in Fig. 13 is total gas. The tool response could not separate gas from hydrocarbons or others type of gas. This includes the injected gas, which is a mix of methane (CH4), nitrogen (N2), and carbon dioxide (CO2). Gasses that contain carbon are methane and carbon dioxide. Thus, the density of carbon dioxide and methane can be estimated using PVT correlation as a function of pressure and temperature as shown in Fig. 14.

The fraction volume of methane and carbon dioxide can be estimated from the analysis of the injected gas. The observed correction for the carbon effects from gas is very minimal, probably less than 2 saturation units. This is mainly due to...
low reservoir pressure where CO₂ and oil is not miscible. When there is a miscible CO₂ flood, the correction could be significant. Fig. 15 shows the three-phase saturation analysis.

**Oil Saturation Uncertainty.** The uncertainty of hydrocarbon saturation was derived from the statistical error measurement and porosity (Jerry Truax et al. 2001) and written as:

\[
\sigma^2_{\text{stack}} = \frac{1}{n} \left[ \sigma^2_{\text{statistic}} + \sigma^2_{\text{residual}} \right] \quad (7)
\]

The statistical errors come from radioactivity processes. The residual errors could be from depth alignment when files from different passes are merged or put into a petrophysical model. Systematic errors caused by depth alignment when the files from different passes are merged can be reduced by doing analysis on CO mode data from only one pass. The statistical error is also reduced by logging at a very slow speed such as 1 ft/min.

Oil saturation uncertainty calculated from the statistical error is about ±7.5 saturation units. Fig. 16 shows the uncertainty of oil saturation due to statistical data from the RMT tool.

**Discussion**

The C/O analysis model for this well uses two main envelopes. The first envelope is for dolomite and the second is for limestone. The data clearly shows two cluster points, which correlate to the lithology of dolomite and limestone.

In the C/O fan chart (Fig. 9) on the left y-axis there are two points close together on the vertex that can be found using extrapolation on the data cloud. The lower limit of the two envelopes...
extrapolates to 100% total porosity and should represent the water point. Both lower limit lines from the two envelopes on the chart should coincide. The same methods were applied to the upper limit. Both C/O fan charts for limestone and dolomite should coincide at one point to extrapolate to 100% porosity as the oil point upper limit.

The practical depth of investigation of the C/O log is very shallow and estimated at only 6 to 8 inches, which is related to the neutron cloud in the inelastic reaction. When the well has open perforations, consider running the tool in the flowing and shut-in condition. Sometimes this is necessary to see the coning effect. For a newly cased well, also consider the effect of the mud filtrate still in the flush zone. Running an RMT survey in an old well is sometimes more challenging, because the well needs to be cleaned up prior to RMT logging. Paraffin scale or radioactive scale (NORM) in the tubing or screen could affect saturation results.

The three-phase saturation solution is archived by combining these two methods of oil saturation correction to account for the carbon contributions from methane and carbon dioxide. This correction is insignificant compared to the oil saturation uncertainty due to statistical radioactive counting.

Another method for solving the three-phase saturation is to combine the C/O analysis and the Sigma analysis. After oil saturation is defined from the C/O analysis then gas saturation is derived from the material balance of the Sigma equation. The total sigma from the log measurement is the sum of the total sigma component in the rock. The Sigma equation is as follows:

$$\Sigma_{\log} = \Sigma_n n_i V_i x \Sigma_r$$  (8)

This method requires that the sigma of water is known and that there is enough contrast between the sigma water, oil, and gas. When the salinity of the formation water is mixed with steam injection, this method cannot be used.

Conclusions

The conclusion and suggestions for best practice drawn from this study are as follow:

- The two analysis methods for C/O and gas saturation are complementary and can be used to solve for three-phase saturation.
- C/O analysis is independent of water salinity and the results are better than results obtained using resistivity for cases of low water salinity and complex lithologies.
- The saturation estimated from the C/O log can be improved by reducing logging speed and the systematic errors can be reduced by lowering the number of passes.
- The gas saturation model is independent of lithology and salinity when salinity is lower than 150 kppm.
- The RMT or TMD-3D surveillance is a robust technique for the cased hole well environment.
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References


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Optimizing Perforating Charge Design for Stimulation

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Abstract
Hydraulic stimulation technologies, which are vital in maximizing the production of unconventional reservoirs, have typically focused on pumping capacities and rates, hydraulic fluid viscosities, and proppant materials. A technology that historically has been overlooked, but is critical to an efficient hydraulic stimulation, is the actual perforations through which the treatment is pumped.

Fundamental rock and fracture mechanics demonstrate that perforation shot density, phasing, and hole size affect breakdown and treating pressures and injection rates, and can be a cause of early screenout. Although some of these perforation parameters are considered in the best practices, perforation hole size is often misunderstood.

Complex computer fracture models, used to plan stimulation and completion programs, often incorporate average hole-diameter values with little consideration of the actual hole sizes or the variance from shot to shot. New research documents how this inconsistency can be considerable when using standard shaped-charge perforators. Nevertheless, perforating charges designed for natural completions, which focus primarily on the depth of penetration, are continuously used before hydraulic stimulation, ignoring the importance of consistent hole size. Advanced simulations using finite element analysis (FEA) have confirmed that fracture placement in a reservoir requiring stimulation would benefit significantly from maintaining consistency in the size of the perforation exit hole.

This work reviews the analysis performed and the subsequent successful field results for a new class of shaped charge. The new fracture charge is engineered to maximize hole-diameter while maintaining a consistent exit-hole diameter independent of well profile and/or gun eccentricity. Designed for perforating before a hydraulic stimulation, a fracture charge has been shown to optimize fracturing efficiency and placement by ensuring that each perforation tunnel contributes equally during the fracture treatment, which contributes to providing cost-effective hydraulic stimulation and maximizing subsequent asset value.

Introduction
Before any stimulation of a cased well completion, a conductive path must be established from the wellbore into the target reservoir rock. Several technologies currently exist, such as sliding sleeves, to create this conduit; however, the most popular technology is perforating because of its overall efficiency, reliability, and historically successful track record. Perforating oil and gas wells using specially designed shaped charge jet perforators has been used extensively since its introduction in the late 1940s. Broad improvements have been applied in the design and materials used since this process was first introduced as the physics have become better understood and testing techniques have advanced and evolved. Shaped charges can now be designed and manufactured for specific applications and conditions, enabling deeper penetration, maximum or minimum casing-hole diameter, and/or the ability to penetrate through only selected tubing or casing strings without penetrating the outer string. However, with all of the advances in perforator design and technology, no shaped charge had been developed to minimize the variation in perforated casing-hole size until now. In addition, stimulation treatment designs have not considered that variation does exist and that it is typically dependent upon gun-to-casing clearance.

Fracture stimulation has demonstrated great success in conventional reservoirs where it was common to focus solely on completing a single zone for production. However, with the industry continuing to trend toward unconventional and resource type plays, which have much lower permeability and larger gross intervals than traditional conventional reservoirs, the focus has shifted to completion methods that can effectively implement multiple stimulation treatments conducted consecutively to maximize efficiency and minimize time to production.

It has been shown that, in horizontal wells drilled in unconventional reservoirs, the degree of stimulated reservoir volume (SRV) is directly proportional to the resulting production (Mayerhofer et al. 2008). It has been shown that SRV can be improved by increasing the number of stimulation points along the horizontal wellbore. This concept can also be applied to vertical wells that are drilled through long intervals of potentially productive stacked sands, silt, shale, and carbonates.

Although there are several viable completion methods applicable to stimulating long intervals in vertical wells, the method using limited entry perforating (LEP) (Lagrone and Rasmussen 1963) is optimal for stimulating multiple intervals simultaneously to achieve a high SRV in a timely and cost-effective manner. The LEP stimulation design uses standard hydraulic equations to define the pressure decrease across the perforations and the pressure decreases that occur between the perforations as a function of hydrostatic and friction pressure. In addition to these pressure decreases, full consideration of the fracturing pressure at each perforation point must be made. The objective of these calculations is to determine the size and number of perforations required at each stimulation point to distribute the stimulation fluid evenly across the intended interval, as shown in Fig. 1.

In practice, one of the main obstacles to LEP design is the inherent circumferential inconsistency in the diameter of the perforations when using standard perforating charges without centralization. Because the stimulation fluid must divide and pass through several perforations and then recombine before flowing down the fracture plane, any variation in the circumferential perforation size can disrupt the fluid convergence, which results in greater than expected injection...
pressures and possible bridging of the propping agent. This behavior is often referred to as near-wellbore tortuosity (Romero et al. 1995), as shown in Fig. 2.

In several ongoing multiple well resource play projects, high injection pressures and bridging of the propping agent frequently occurred during the stimulation. An analysis of the injection pressures led to the premise that the standard perforating charges were not optimal and that a high degree of tortuosity existed. Treatment fluids were believed to be contributing through only some of the perforations because of the known inconsistent perforation diameter circumferentially around the wellbore caused from variations in gun-to-casing wall clearance. This casing-hole variation was assumed to cause a high degree of near-wellbore tortuosity. To test this premise, an existing perforating charge with a shallower penetration and a more consistent hole diameter than the previous charge was used; a moderate reduction of injection pressure and a reduction in the frequency of bridging of the propping agent was observed. This observation led to the research, design, and development of a new optimized perforating shaped charge tailored for perforating before stimulation treatment begins.

Fracture Physics – Casing Hole Size and Orientation

We have developed a simplified model to preliminarily investigate the role of perforation tunnel geometry during the hydraulic fracturing process. In particular, because of the known effect of gun-to-casing clearance and the challenges observed while treating wells, the focus was placed on the consistency of the casing entrance-hole diameter in affecting fracture initiation. The model incorporates a finite element stress analysis with a fracture initiation criterion. The finite element analysis has been performed using the commercial software ABAQUS/Standard (2011) to determine the stress distribution around the perforating tunnel. The model developed establishes the connection between the breakdown pressure and the local stresses along the surface of the perforation tunnel.

As shown in Fig. 3 (only half of the model is shown), the simplified model consists of the steel casing with six holes over a 12-in. interval and the reservoir. Each casing hole is treated as a cylindrical hole. Corresponding to each casing hole, a cylindrical perforation tunnel is created with the length of 15 in. and the same diameter as that of the casing hole. The reservoir model height is equal to the perforated interval of 12 in. and a radius of 50 in. Additional study indicated that the reservoir in the present model is sufficiently large such that the stress distribution near the perforation tunnel and the casing does not depend on the reservoir boundary. Fig. 4a shows the mesh configuration of the reservoir model; Fig. 4b provides a close view of the region near the perforating tunnel. The mesh is refined in the region near the perforation tunnel. For simplification, both the reservoir rock and the steel casing are considered as linear elastic materials. A uniformly distributed pressure, \( p = 100 \text{ MPa} \) is applied to both the surface of the perforating tunnel and the casing.

In this study, the entrance-hole diameters of the six perforation tunnels were varied, but the influence of the tunnel length and irregularities of the geometry of the real perforation tunnel has not been explored. Three cases are considered:
(1) an ideal case in which all six tunnels have the same entrance-hole diameter; (2) a specific case in which the entrance-hole diameters vary from 0.36 to 0.48 in., as a representative having less variation in the perforation entrance-hole diameters (EHD) created by a specially designed shaped charge; (3) a specific case in which the entrance-hole diameters vary from 0.25 to 0.55 in., as a representative having larger variation in the perforation EHD created by a conventional deep-penetration shaped charge. As testing has confirmed and will be presented later in this work, the perforation EHD varies relative to the clearance between the perforating gun and the casing wall.

Fig. 5 shows the numerically predicted distribution of the local maximum principal stress (MPS) on the surfaces of the perforation tunnels and the wellbore. In the figures, red indicates a large magnitude of the stress, and blue indicates a relatively small magnitude. For all three cases, the local maximum principal stress (MPS) is always on the top surface of the perforation tunnel near the base of the perforation and near the wellbore surface. This outcome is consistent with the previous work completed by Behrman and Elbel (1991). The entrance-hole diameter greatly contributes to fracture initiation, whereas the tunnel length has a much smaller effect on the initial perforation breakdown.

To derive a fracture initiation criterion, we will consider the following hydraulic fracturing process. As the fluid is injecting into the well, a very high pressure will build up on the casing surface and the perforation tunnel surface, resulting in locally elevated stresses in the reservoir rock near the perforation tunnel. In general, the fracture will initiate when the maximum principal stress, $\sigma_1$, of the rock reaches the tensile failure strength of the rock, $T_{\text{fail}}$, which can be written as:

$$\sigma_1 = T_{\text{fail}}$$  \hspace{1cm} (1)

Furthermore, based on the present finite element analysis, the hydraulic pressure generated by the injection fluid is linearly proportional to the calculated local max principal stress, such that

$$\sigma_1 = Kp$$  \hspace{1cm} (2)

Where $K$ is the coefficient, which is a function of reservoir rock properties, as well as the geometry of the perforation tunnel. Substituting (1) into (2), we obtain the relation between the breakdown pressure, $p_{\text{bd}}$, and the tensile failure strength of the rock, $T_{\text{fail}}$, as:

$$p_{\text{bd}} = \frac{T_{\text{fail}}}{K}$$  \hspace{1cm} (3)

### Table 1

Summary of FEA Results Comparing EHD to MPS

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Entrance-Hole Diameter</th>
<th>Maximum Principal Stress</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Minimum</td>
<td>Maximum</td>
</tr>
<tr>
<td>Case 1</td>
<td>0.43 in.</td>
<td>152.7 MPa</td>
</tr>
<tr>
<td>Case 2</td>
<td>0.36 in.</td>
<td>0.48 in.</td>
</tr>
<tr>
<td>Case 3</td>
<td>0.25 in.</td>
<td>0.55 in.</td>
</tr>
</tbody>
</table>

Figure 4. Finite element mesh configurations.

Figure 5. Contour plots of the local Maximum Principal Stress (MPS) on the surfaces of the perforation tunnel and the wellbore. The local Maximum Principal Stress (MPS) is always on the surface of the perforation tunnel near the entrance, so the entrance-hole diameter greatly contributes to fracture initiation.
Eq. 3 indicates that for a given reservoir rock (i.e., $T_{\text{fract}}$ is a constant), the breakdown pressure is proportional to the inverse of the coefficient $K$. A larger value of $K$ leads to a reduced breakdown pressure. Furthermore, according to the numerical results in Fig. 3, for a given pressure, the local maximum principal stress (MPS) increases as the hole diameter decreases. For example (i.e., in Case 3), for the smallest entrance-hole diameter ($D = 0.25$ in.), the MPS equals $144.8 \text{MPa}$, whereas for the largest entrance-hole diameter ($D = 0.55$ in.), the MPS is $162.5 \text{MPa}$. Consequently, the larger the entrance-hole diameter, the larger the value of the coefficient $K$. Finally, we can conclude that for a given reservoir rock, the breakdown pressure will be reduced as the perforation tunnel diameter increases. This conclusion agrees with previous work that documents the importance of casing hole size over penetration (Behrman and Nolte 1998).

Although breakdown pressure can be reduced locally by a larger entrance-hole diameter, the consistency of all hole diameters is also critical for a successful breakdown and stimulation. An important factor affecting the efficiency of hydraulic stimulation process is the ability to pass fluid through all perforations, specifically those aligned with the preferred fracture plane, which enables each hole to contribute to a successful breakdown and stimulation. If the variation of the entrance-hole diameter of the neighboring perforation tunnels is too large, then the fracture will initiate at the entrance of the larger hole, leaving the smaller holes less effective and possibly creating a tortuous path as the fracture grows and aligns itself with the preferred fracture plane. This is because after the fracture occurs at a single perforation hole, the diameter of the damaged hole will be further enlarged, and the required local breakdown pressure will be further reduced, thus making the fracture grow locally.

**Perforator Performance – Casing Hole Size Varies**

Jet perforator performance can vary greatly depending upon the particular materials used in the charge case and liner. In addition, the geometric shape and dimensions of the liner, charge case, and explosive column can also affect performance. For example, the two most common classes of shaped charges for the oil and gas industry are big hole (BH) and deep penetrating (DP) charges; BH charges typically use a parabolic shaped solid metal liner, whereas DP charges most commonly have a liner pressed from powdered metal particles into a convex shaped liner. As their names suggest, the performance of each class of charge is unique. Under a given set of conditions, a correlative tradeoff exists between the penetration of a charge and the casing hole size that it creates. In other words, as the penetration becomes greater, the casing hole size becomes smaller; conversely, as the hole size created becomes larger, the depth of penetration becomes smaller.

Just as casing hole size and penetration can vary depending upon the particular design of a shaped charge, the environment in which it is detonated can have a major influence upon performance. Particularly important to this work is the influence of the distance between the perforating gun and interior casing wall, which is known as clearance.

Perforating gun systems, regardless of conveyance, will likely be against the casing wall in a decentralized position, with charge phasing oriented toward an unknown direction unless a specific mechanism is used to centralize or orient the gun. As a result, it is impossible to know the exact clearance that a shaped charge will have, but known gun diameter and casing size can provide an expected maximum and minimum clearance. The amount of clearance between the perforating gun and the casing wall significantly affects casing hole size for most BH and DP charges.

An extensive evaluation was performed of the industry-available shaped charges often used to perforate wells before stimulation treatment. The most common good hole (GH) charge used throughout the North America frac market was evaluated and shot under quality control (QC) setup conditions, using minimum and maximum clearances. Fig. 7 provides an example the significant variation that can exist with a 3 ½-in.

**Table 2**

<table>
<thead>
<tr>
<th>Variable</th>
<th>Entrance-Hole Diameter</th>
<th>Maximum Principal Stress</th>
</tr>
</thead>
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<tr>
<td>Test Number</td>
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<tr>
<td>Minor EHD (in.)</td>
<td>0.520</td>
<td>0.480</td>
</tr>
<tr>
<td>Major EHD (in.)</td>
<td>0.530</td>
<td>0.520</td>
</tr>
<tr>
<td>Average EHD (in.)</td>
<td>0.525</td>
<td>0.500</td>
</tr>
</tbody>
</table>
gun assembly inside 5½-in. casing and the QC setup in which it was tested. Table 2 presents the measurements of the casing plate coupons perforated using the minimum and maximum clearance in Fig. 7. Fig. 8 outlines a summary of completed test program datapoints, highlighting significant variance in hole diameter relative to clearance, as well as significant variance in charge performance.

Data sheets commonly referenced within the industry to identify perforator performance include API 19B Section I, or a less controlled and outdated method RP43. These testing methods require the detonation of a representative perforating gun inside an appropriate-sized segment of casing placed inside a cement target. After gun detonation, each casing hole created from the perforation jet is measured and documented. The average of these casing holes, regardless of clearance, is typically presented as the shaped charge or gun system performance. Therefore, neither the minimum or maximum hole size created is often understood nor the variance without looking specifically at hole size relative to clearance.

Optimized Shaped Charge

Shaped charges are fundamentally described as having three basic components: charge case, explosive load, and liner. The performance of a shaped charge or gun system is varied through modifying the geometry, quantity, or composition of those main components. Recent studies have shown that the manufacturing process can also significantly affect performance. Variations of these three components, as has been demonstrated and widely accepted within the industry, can be optimized to tailor the performance of a charge for a given set of conditions, including optimizing hole size and hole size consistency relative to gun-to-casing clearance. Taking into consideration the importance of hole-size consistency, a shaped charge jet perforator was developed and manufactured to minimize this variation. Through minimizing hole size variation in non-oriented perforations, fracture efficiency would improve. This is a result of all of the perforation holes receiving injected treating fluids, rather than only the largest holes. As previously presented in Fig. 8, the minimal clearance generally provides the greatest hole size; consequently, the perforations on the low side of the casing would most likely receive the majority of injected treating fluids, regardless of the preferred fracture plane. Fractures that initiate from larger perforations greater than 30 degrees from the preferred fracture plane demonstrate higher treating pressures and decreased width, a known effect of near-wellbore tortuosity (Abass et al. 1994).

The newly developed 21.0 gram fracture charge was loaded into a 3½ in. and 3¾ in. 6 spf 60 deg gun assembly and detonated within 4½ in. and 5½ in. casing, respectively, to represent the most common perforating condition in the North America stimulation market. This testing is commonly referred to as a barrel test; its purpose is to confirm and validate that a charge could be tailored to generate a more consistent hole size, regardless of clearance. Fig. 9 and Table 3 present the results, comparing casing hole size consistency relative to gun-to-casing clearance between the newly optimized fracture charge, a 21.0 gram shaped charge (Charge A) and an industry-available 19.0 gram GH shaped charge (Charge B).

Although the fracture charge does not have the largest hole size, it also does not have the smallest. As expected from initial QC shots, the optimized frac charge significantly outperformed the alternative charges in the fully loaded gun system test when detonated in a representative segment of casing having the tightest variation. Fig. 10 illustrates the average performance, which provides insight into how the casing hole variation could be a significant contributor to near-wellbore tortuosity.
Figure 8b, in the appendix benchmarks the Frac charge performance compared to the initial clearance sensitivity data set of Fig 8.

For example, if the preferred fracture plane was transverse to the horizontal wellbore, and the well was cluster perforated with non-optimized charges, only the perforations closest to the lowside with the significantly larger hole diameter would likely contribute to the treatment, making nearly half non-contributing. Alternatively, the optimized fracture charge would generate a perforation tunnel with a greater probability of accepting treating fluids proportionally.

Field Studies
The first phase of field trials consisted of five wells, with a total of 25 stages, to evaluate the newly designed and optimized fracture shaped charge. The well completions were made in the Atoka-Strawn formations for two wells and the Wolfcamp-Leonard (Wolfberry) for the remaining three wells. All five wells are located in the Midland basin of West Texas. These field trials were designed to test the effectiveness of the new charge and the premise that a smaller variance in perforated hole size and less emphasis on depth of penetration would improve the connectivity between the wellbore and the fractures created from it. This section includes examples of four of the 25 stages, showing the rate and pressure responses of treatments using the new charge and how these parameters compare to previous treatments.

Field Trial 1. Field Trial 1 was conducted in the Atoka formation. This interval consisted of medium hard to hard limestone interbedded with shale of various properties and having a fracture gradient ranging from 0.85 to 0.95% of the overburden gradient. Area stimulation history shows that it is difficult to initiate fractures in the interval and difficult to obtain the designed injection rates within the pressure limits of the casing. Six individual clusters of perforations were strategically spaced across 300 vertical ft of Atoka formation. The perforations were shot with 60-degree phasing and with a shot density of 6 shots per ft, for a total of 49 perforations.

Treatment data from a recently completed offset well was used to evaluate the performance of the new optimized fracture shaped charge. This well was also completed with six individual clusters of standard perforations spaced across 300 vertical ft of Atoka formation. These perforations were also shot with 60-degree phasing and with a shot density of 6 shots per ft, for a total of 49 perforations.

On the offset well, an injection rate of 55 bpm was obtained with the injection pressure approaching 6,000 psig, near the casing limit, in approximately 29 minutes. The test well using the new perforating charge reached this treating pressure in approximately the same amount of time, but it was possible to continue to increase the rate to 70 bpm, as shown in Fig. 11. An increase of 15 bpm was obtained for the same pressure by using the new perforating fracture charge.

<table>
<thead>
<tr>
<th>Charge</th>
<th>3-1/8 in. Perforating Gun in 4-1/2 in. Casing</th>
<th>3-3/8 in. Perforating Gun in 5-1/2 in. Casing</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Average (in.)</td>
<td>Max (in.)</td>
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<tr>
<td>Frac Charge</td>
<td>0.46</td>
<td>0.47</td>
</tr>
<tr>
<td>Charge A</td>
<td>0.49</td>
<td>0.52</td>
</tr>
<tr>
<td>Charge B</td>
<td>0.50</td>
<td>0.54</td>
</tr>
</tbody>
</table>

Figure 9. Barrel test results from charge comparison.

Figure 10. Barrel test performance overview.
Field Trial 2. Field Trial 2 was conducted in the Lower Spraberry formation. This interval consisted of medium soft to soft limestone muds interbedded with shale of various properties; the fracture gradient ranged from 0.60 to 0.65% of the overburden gradient. Area stimulation history shows the interval to be easy to initiate fractures and to obtain the designed injection rates within the pressure limits of the casing. Five individual clusters of perforations were strategically spaced across 250 vertical ft of Spraberry formation. The perforations were shot with 60-degree phasing and with a shot density of 6 shots per ft, for a total of 48 perforations.

Treatment data from an offset well was used to evaluate the performance of the new perforating charge. This well was completed with six individual clusters of standard perforations spaced across 250 vertical ft of Spraberry formation. These perforations were also shot with 60-degree phasing and with a shot density of 6 shots per ft for a total of 57 perforations.

On the offset well, the designed injection rate of 65 bpm was obtained with the injection pressure approaching 2,200 psig in approximately 3 minutes. The test well using the new perforating fracture charge reached this treating pressure in approximately the same amount of time, but at a lower designed rate of 60 bpm. As shown in Fig. 12, both wells were treated at approximately the same injection pressure of 2,200 psig, although the well with the new perforating fracture charges had fewer holes. The rate per perforation in the test well was 1.25 bpm vs. the offset wells 1.14 bpm. This amounts to an approximately 10% improvement in perforation flow area. Table 4 provides details of Field Trial 2.

Field Trial 3. Field Trial 3 was conducted in the Middle Spraberry formation. This interval consisted of medium soft to soft limestone muds interbedded with sand and siltstones of various properties; the fracture gradient ranged from 0.50 to 0.52% of the overburden gradient. Area stimulation history shows the interval to be easy to initiate fractures and to obtain the designed injection rates within the pressure limits of the casing. Six individual clusters of perforations were strategically spaced across 250 vertical ft of Spraberry formation. The perforations were shot with 60-degree phasing and with a shot density of 6 shots per ft for a total of 52 perforations.

On the offset well, the designed injection rate of 65 bpm was obtained with the injection pressure approaching 1,800 psig in approximately 3 minutes. The test well using the new perforating fracture charge reached this treating pressure in approximately the same amount of time, but at a lower designed rate of 60 bpm. As shown in Fig. 12, both wells were treated at approximately the same injection pressure of 1,800 psig, although the well with the new perforating fracture charges had fewer holes. The rate per perforation in the test well was 1.25 bpm vs. the offset wells 1.14 bpm. This amounts to an approximately 10% improvement in perforation flow area. Table 4 provides details of Field Trial 3.

Table 4

<table>
<thead>
<tr>
<th>Stage #5, Field Trial 2.</th>
<th>Old Charge</th>
<th>New Frac Charge</th>
<th>Difference</th>
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<td>Clusters</td>
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<td>5</td>
<td>-1</td>
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<td>Holes</td>
<td>57</td>
<td>48</td>
<td>-9</td>
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<tr>
<td>Time to Rate</td>
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<td>0</td>
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<tr>
<td>Rate</td>
<td>65</td>
<td>60</td>
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<td>Pressure</td>
<td>2,212</td>
<td>2,175</td>
<td>-37</td>
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<tr>
<td>ISIP</td>
<td>1,004</td>
<td>1,013</td>
<td>9</td>
</tr>
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</table>
6 minutes. The test well using the new perforating charge reached this treating pressure in approximately the same amount of time and at the same rate of 65 bpm. As shown in Fig. 13, both wells were treated at approximately the same injection pressure of 1,800 psig, although the well with the new perforating charges had fewer holes. The rate per perforation in the test well was 1.25 bpm vs. the offset wells 1.12 bpm. This amounts to approximately an 11% improvement in perforation flow area. Table 5 provides details of Field Trial 3.

Field Trial 4. Field Trial 4 was conducted in the Upper Spraberry formation. This interval consisted of medium soft to soft limestone muds interbedded with sand and silt stones of various properties; the fracture gradient ranged from 0.50 to 0.52% of the overburden gradient. Area stimulation history shows the interval to be easy to initiate fractures and to obtain the designed injection rates within the pressure limits of the casing. Six individual clusters of perforations were strategically spaced across 200 vertical ft of Spraberry formation. The perforations were shot with 60-degree phasing and with a shot density of 6 shots per ft, for a total of 52 perforations. Treatment data from an offset well was used to evaluate the performance of the new perforating charge. This well was completed with five individual clusters of standard perforations spaced across 200 vertical ft of Spraberry formation. These perforations were also shot with 60-degree phasing and with a shot density of 6 shots per ft for a total of 52 perforations.

On the offset well, the designed injection rate of 60 bpm was obtained with the injection pressure approaching 2,000 psig in approximately 5 minutes. The test well using the new perforating charge reached this treating pressure within approximately 3 minutes, but at higher injection rate of 65 bpm. As shown in Fig. 14, both wells were treated at approximately the same injection pressure of 2,000 psig, but the well with the new perforating charges pumped at a higher rate of 65 bpm for the same number of holes. The rate per perforation in the test well was 1.25 bpm vs. the offset wells 1.15 bpm. This amounts to approximately an 11% improvement in perforation flow area. Table 6 provides details of Field Trial 4.

$$\text{Table 5}$$

<table>
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<tr>
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<tr>
<td>Clusters</td>
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<td>Holes</td>
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<td>Time to Rate</td>
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<td>0</td>
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<tr>
<td>Pressure</td>
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<td>1,800</td>
<td>-12</td>
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<td>ISIP</td>
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$$\text{Table 6}$$

<table>
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<td>104</td>
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Conclusion
The following conclusions are made from the development testing and initial field trial observations contained and presented within this work:

- Shaped charge jet perforators can be optimized for a given set of conditions, specifically to generate a more consistent casing-hole diameter relative to gun-to-casing clearance.
- Perforation hole size is an important component in minimizing fracture breakdown and treating pressures.
- Conventional shaped charge jet perforators (non-optimized) typically generate a larger-hole diameter with minimal clearance (low side) and a much smaller hole diameter with greater clearance (high side).
- Consistent perforator hole size, azimuthally around the wellbore, has demonstrated a 10% to 11% improvement in effective (contributing) perforation flow area in field trials.
- Consistent perforator hole size, as demonstrated in field trials, has the potential to decrease near-wellbore tortuosity, thereby reducing treating pressures and the likelihood of early screenouts.

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The authors would like to thank our respective companies, Halliburton and Piedra Operating, for supporting this work, research, and testing. In addition, we would like to show great appreciation to Cam Le for his contribution, the Permian PE group for thorough and objective review of treatment performance, and Kyle Wooster of Jet Research Center.

References

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Real-Time Proactive Optimal Well Placement Using Geosignal and Deep Images

Michael Bittar, Roland Chemali, and Jason Pitcher, Halliburton; Robert Cook and Craig Knutson, Pioneer Natural Resources

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Abstract

Modern oil field drilling operations through complex reservoirs can be extremely challenging because geological models are often limited to the resolution of seismic data. Often, these reservoirs have significant variations that cannot be fully anticipated before drilling. Efforts toward maximizing production from these complex reservoirs through optimal well placement require increasingly sophisticated geosteering and formation evaluation capabilities.

Advances in directional logging-while-drilling (LWD) resistivity measurements improved real-time geosteering by providing discrete azimuthal measurements, deep images, and distance to the formations from above, below, and to the side of the sensor while drilling horizontally or at high-inclination angles through the reservoir. Distance-to-bed boundaries calculation is achieved by means of the geosignal, a new geosteering signal. Derived in real time, the geosignal is azimuthally sensitive and strongly dependent on the distances to boundaries.

These novel measurements, combined with well steering software, enable geosteering engineers to steer the well not only on resistivity variations but also on direct deep resistivity images and on azimuthal geosignal. Boundaries are identified as they approach the well from above, below, and any direction around the sensor. A complete picture improves the understanding of the reservoir’s geology and aids in placing the well in thin reservoirs. It also improves the capability of steering the well through the most productive part of the reservoir while maintaining a desired distance from adjacent formations.

This paper describes the planning and execution of a typical well placement operation accomplished with this new technology. New interpretation methods specific to deep images are illustrated on real data and many examples are shown. The paper also provides details about the workflow of geosteering based on this new azimuthal deep-reading technology and discusses the benefits and limitations, lessons learned, pitfalls, and best practices. Finally, field examples from around the world are included to show the usefulness of this new technology for well placement and formation evaluation in various types of hydrocarbon reservoirs.

Introduction

The oil and gas exploration and production industry is increasingly migrating to high-angle wells, especially in offshore operations. The partial departure from vertical wells began in the 1980s and has accelerated in recent years because the technological advances have made it easier and less risky to drill extended reach wells in many types of reservoirs. There are multiple advantages of high-angle wells and horizontal wells. A horizontal well generally yields the same initial production as that of several vertical wells combined, which significantly reduces the surface infrastructure requirements. In an offshore field development, a single platform can launch multiple high-angle wells in many directions, covering vast areas that would otherwise require multiple platforms with vertical wells. During the life of the field, if properly placed, horizontal wells enable a more efficient sweep of the producible hydrocarbon than vertical wells, leading to higher volumes of ultimate oil and gas recovery. In addition to cost savings and increased revenue, horizontal wells offer a reduced footprint for a given hydrocarbon production, significantly reducing the effect on the environment.

Horizontal wells, however, present a new set of challenges and opportunities. One of the most important challenges is the placement of the well in an optimal location in the reservoir. Consider first the traditional scheme in which vertical wells are drilled to intersect horizontal formations. The probability of successfully intersecting the pay zone is high. The productive interval is readily identified, based generally on resistivity and porosity logs. The casing is perforated to optimize the initial and cumulative recoveries, and the well is brought on line. As oil and gas are produced, the various contacts move upward (assuming a water drive); the hydrocarbon is swept by the rising water zone in a predictable manner (Fig. 1). Sometimes this simple scheme is made more complex by the injection of water on the flanks of the reservoir, creating a sweep from the outer edges toward the producing wells. The same discussion holds true for moderately deviated wells (Fig. 1).

By contrast, high-angle or horizontal wells must be continually guided to intersect the reservoir, to land properly, and to remain within the optimal portion of the productive zone (Fig. 2). Some knowledge of the vertical position, thickness, and lateral extent of the hydrocarbon interval is required. After the well has landed in the reservoir, it is desirable that it remain within the productive interval for as long a span as possible. Any well length drilled out of the productive zone represents a wasted investment. Production from out-of-reservoir intervals is either nil or high in water cut or gas cut. In all of these instances, the economical outcome is adversely affected. From the driller’s perspective, remaining within the zone is also very advantageous. Because the beds surrounding the hydrocarbon-bearing formation tend to have less desirable mechanical properties than the reservoir, venturing out of the zone can increase the risk for the drilling operation. Simply stated, even in the least complex reservoirs with
layer cake geology, it is important to steer horizontal wells to maximize production and to realize the full benefit of horizontal drilling.

Departing from the simple layer cake model and considering a more realistic complex geology in which boundaries, including reservoir roofs, are irregularly shaped (Fig. 3), the necessity for geosteering becomes clear. It is important to keep in mind that any a priori knowledge of the geometry of the reservoir is imprecise. Well placement often requires locating the well within a few feet from a boundary, including the reservoir roof and oil/water contact. By contrast, geological models are defined to only within several tens of feet. This limitation stems from the fact that geological models are usually based on seismic sections and on nearby wells. Seismic imaging has a bed resolution of 70 ft in the more favorable situations. In general, a resolution of 110 ft is quoted as the average expected value (Sheriff 1997). Furthermore, the absolute depths of geological events are known with even less accuracy unless the field is already well drilled and the seismic time-to-depth conversion is well established. These limitations preclude the exclusive use of geometrical navigation to properly and reliably place horizontal wells in complex reservoirs or thin reservoirs. Geosteering is advised to complement survey-based navigation.

**Reactive and Proactive Geosteering**

Geosteering is the discipline of placing the well in relation to geological boundaries and markers using real-time measurements, notably LWD. Geosteering is necessary when the well must be precisely located inside the reservoir. The alternative of relying exclusively on survey and geological maps is not viable. The survey accuracy in real time is of a few feet at best; the accuracy of geological maps is of several tens of feet. Their combined uncertainty is too large for placing the well optimally within the reservoir. In many cases, the well would exit the reservoir prematurely. It is impractical to aim from the surface to place a well geometrically within a 10 ft thick target when the true depth of the entire target is only known to within 70 ft. For this reason, it is best to navigate by referring continually to the geological events, and to steer the well accordingly. With the proper LWD technology, the relative distance between the well being drilled and a boundary can be determined with great accuracy.

Two types of geosteering methods have been described in previous publications. The first method, reactive geosteering, is based on the various LWD responses as the well crosses a geological boundary. In one early implementation, an up-down gamma ray was used to recognize in real time whether the well had exited into the shale from below or from above.
(Jan and Harrell 1987). Direct triangulation of the gamma curves helped to estimate the relative angle of exit. The information was used while drilling to steer the well back into the reservoir. Reactive geosteering occurs when the decision to change the well direction is made after the well has crossed a boundary, and the information obtained at that crossing helps to guide the decision.

The most advanced form of reactive geosteering relies on real-time, near-wellbore images while drilling. These images are obtained by azimuthal sensors with shallow investigation and include azimuthal density, azimuthal natural gamma, and micro-electrical images (Fig. 4). Reactive geosteering with real-time images is described in particular by Ballay et al. (2001).

The second form of geosteering, proactive geosteering, consists of maintaining the well path in the reservoir by anticipating reservoir exits long before they occur. The early implementation of proactive geosteering relied on deep-reading non-azimuthal resistivity measurements to recognize approaching boundaries before they intersect the wellbore. The method was perfected to steer 30 ft above an oil/water contact in the Grane field of the Norwegian sector of the North Sea (Iversen et al. 2003). One shortcoming of non-azimuthal resistivity soon emerged: the signature of an approaching boundary is identical for geological events approaching the well from above, below, or the side (Chemali et al. 2008). In Fig. 5, the same signature is observed for a well dropping toward the oil/water contact or approaching the roof.

Advanced Proactive Geosteering with Azimuthal Deep Resistivity

Proactive geosteering is quite beneficial from multiple standpoints. First, the well remains within the reservoir for longer intervals, yielding higher initial production rates. In addition, if the well is placed on an optimal path within the reservoir, a more effective sweep leads to higher ultimate cumulative oil and gas recovery. From the driller’s point of view, avoiding exits into the shale roof keeps the bit in the generally more competent and better drillable formation.

The ambiguity in the response of non-azimuthal deep resistivity LWD tools, however, makes it hazardous to base real-time decisions on this family of measurements. Fig. 5 shows the error that can easily result in a vertical geometrical section when the wrong guess is made about the direction of the approaching low resistivity formation. The log separation between deep and shallow resistivity measurements only indicates the impending exit from the reservoir; it does not specify whether the imminent exit is from above, below, or the side. Precisely for that reason, a new type of propagation resistivity tool was developed in recent years (Bittar 2002; Bittar et al. 2007). The new device can indicate the approaching lower resistivity formation and determine its direction relative to the wellbore.

As shown in the simulations of Fig. 5, the azimuthal deep resistivity response resolves the ambiguity by measuring resistivity values in all 32 bins around the well axis. For ease of interpretation, the resistivity response is shown for the deeper resistivity measurement at only two azimuth values: when the array is pointing up and when the array is pointing down. As illustrated in Fig. 7, the pattern of separation between the case of the well dropping into a
Figure 6. The azimuthal deep resistivity array features tilted receiver antennas. As the BHA rotates, the resistivity measurements scan in 32 discrete azimuthal sectors or bins.

Figure 7. Azimuthal deep-reading LWD resistivity identifies an approaching boundary before the well crosses it, and helps to determine whether the less resistive formation is approaching the well from above (right) or from below (left).

lower resistivity interval, shown on the left, is opposite that of the well emerging upward in a lower resistivity interval, shown on the right.

The coil array of the instrument shown in Fig. 6 includes three compensated transmitter-receiver spacings and one additional tilted receiver located farther away from the transmitter and closer to the bit. A sub array is compensated when the transmitters are located symmetrically with respect to the receiver pair, and their signals are combined to minimize borehole effects and electronic drifts (Clark et al. 1990). Resistivity images from the compensated spacings, and the geosignal from both compensated and non-compensated spacings and their specific application to proactive geosteering, are described in greater detail in subsequent sections.

**Proactive Geosteering with Deep Resistivity Images from Azimuthal Deep Resistivity**

The resistivity measurements from the compensated spacings are acquired in 32 bins around the circumference as the BHA rotates. For any given spacing, these readings are displayed as a resistivity map, thus creating deep resistivity images. Unlike the near-wellbore images of Fig. 4, the deep resistivity images originate from between several inches and several feet from the borehole wall. The coil array features multiple transmitter-receiver spacings, each of which operates at two or three different frequencies. As a rule, the longer spacing (64-in.) senses significantly deeper into the formation than the shallower spacing (16-in.). The signals from the lowest frequency of 125 kHz have deeper investigation capabilities than those from the highest frequency of 2 MHz. Similarly, resistivity images generated from the attenuation measurement sense more deeply than those from the phase measurements.

When intersecting a sequence of beds, the deep resistivity images exhibit the traditional smiling and frowning sinusoidal patterns of the type shown on near-wellbore images. The frowning patterns shown on the near-wellbore images of Fig. 4 are readily related to the well being drilled downdip. There is, however, one major difference between deep electrical images and near-wellbore electrical images. The sinusoidal patterns of deep electrical images are related to the radial depth at which the image originates (Chemali et al. 2009). The deeper the image, the larger the amplitude of the sinusoidal pattern. Fig. 8 shows modeling results that confirm the intuitive thought process. Fig. 9 illustrates this phenomenon with an actual well example.

A more important aspect of deep electrical images is the bright spot phenomenon that occurs near boundaries. Fig. 7, which is limited to only up and down resistivity, shows how the polarization horns displayed on non-azimuthal resistivity near reservoir boundaries split into one pronounced horn on the side of the reservoir and one less pronounced horn on the opposite side. When developed into a full image, the polarization horn becomes a bright spot, as shown in Fig. 10. The model consists of a well being drilled up toward a less resistive roof. A bright spot displays as the well approaches the roof and then fades away as the well moves away from the roof. The image from the longer spacing senses more deeply into the formation. The bright spot from the 48-in. spacing image displays sooner and stays visible later than the bright spot for the 16-in. spacing.

Although azimuthal resistivity measurements and images help to detect farther into the formation than traditional near-wellbore imaging LWD, they are not as deep as the geosignal described in the next section.

**Proactive Geosteering with Geosignal from Azimuthal Deep Resistivity**

The azimuthal deep resistivity array shown in Fig. 6 also produces a geosignal that is sensitive to only lateral variations in resistivity (Bittar 2002; Seifert et al. 2009). The main benefit of the geosignal is that it is differential in nature and therefore highly sensitive to side-approaching geological events. The geosignal is best
illustrated by the sequence shown in Fig. 11. For simplicity, the cases shown include only 4 bins around the circumference, rather than the 32 bins of the actual measurement.

In Fig. 11, a representation of the phase measurement at one of the tilted receivers is given by the magnitude and angle of a red arrow as the antenna array rotates with the BHA. The well is in a homogeneous 20 ohm-m oil reservoir and is approaching a less resistive 1 ohm-m shale roof. The phase measurement increases as the tilted receiver points up and decreases as the receiver points down. The geosignal in any given bin is obtained in the first approximation by using the difference between the phase measured in that bin and the phase measured in the opposing bin. In this instance, the geosignal has a positive value in the upper bin and a negative value in the lower bin. The geosignal is zero in the side-facing bins.

If, instead of the configuration of Fig. 11, the well was running in the middle of a homogenous 20 ohm-m reservoir away from any boundary, the phase magnitude would be identical in all bins and the geosignal obtained by subtracting phase values from opposing bins would be zero. Similarly, if the configuration of Fig. 11 was replaced by one in which the well is dropping toward a less resistive 1 ohm-m water zone, the geosignal would be reversed from the example shown in Fig. 11. Specifically, it would be positive in the lower bin and negative in the upper bin.

For ease of interpretation, the geosignal from the up-looking bin (Bin 1) is plotted with its sign and magnitude. In a vertical geological section, a positive geosignal indicates an approaching low resistivity formation located above the well. A negative geosignal indicates an approaching low resistivity formation below the well. If the geosteering is conducted in 3D and side-approaching boundaries are expected, then the geosignal can be plotted along an arbitrary angle, or displayed as an array or an image.

The method for deriving the phase geosignal is readily extended to deriving an attenuation geosignal. The latter tends to sense more deeply, but with less resolution than the former.

The geosignals from the azimuthal deep resistivity were characterized both theoretically and experimentally. There was excellent agreement between the two approaches (Seifert et al. 2009). The geosignal is a strong function of the distance-to-bed boundary and of the conductivity of the approaching formation. As expected, geosignals from longer spacings detect farther away from the wellbore than geosignals from shorter spacings. Lower frequency geosignals are less affected by skin effect, but are generally smaller in magnitude. The selection of the correct geosignals to pulse in real time for geosteering is an essential part of the pre-job planning and is usually based on pre-well modeling.

Fig. 12 shows one typical geosignal interpretation chart. This chart clearly illustrates that the magnitude of the signal varies strongly with the distance to boundary. It also suggests that the measurement is more likely to detect an approaching low resistivity formation from inside the higher resistivity reservoir than the converse.
In the presence of a nearby low resistivity formation, the phase measured by a tilted receiver varies with its orientation relative to the boundary. As the coil array rotates with the BHA, the phase measurement is stored in 32 bins. The geosignal is then derived by combining phase readings from opposite bins.

The geosignal interpretation chart corresponds to a well approaching a reservoir roof. The geosignal rises above the noise floor much sooner when the well is in the high resistivity reservoir approaching the lower resistivity caprock.

One important feature of the chart is the flat spot that occurs where the sensor straddles the boundary. The sensor can detect when the well is very near the boundary, but it cannot detect whether it is in the reservoir side or the shale side of the boundary. Consequently, this proactive geosteering sensor should be complemented with a shallow reading imaging sensor of the type used for reactive geosteering.

Alaska Example
A horizontal well was planned in the Kuparuk sand at Oooguruk Island, off the coast of the North Slope in Alaska (Pitcher et al. 2010). This sand averages 25 ft thick in this area and is fairly clean, with some disseminated and nodular siderite. The Kuparuk is bounded by Kalubik shale above and the Miluveach shale below. Both shales are mechanically unstable when penetrated at high angles, which provides a high potential for stuck pipe. The LWD tool selection was based on several criteria. The primary goal was to avoid exiting through the top or bottom of the sand. A review of the offset logs suggested that the resistivity contrast at the upper and lower boundaries of the target was significant and that these boundaries could be detected before the exit of the bit. The detection of the exit was contingent on the exit being stratigraphic in nature, rather than the result of unforeseen faulting, and on the approach angle being low enough to provide warning with the resistivity tools. These constraints indicated that an azimuthal resistivity tool would be the best tool for the job. This tool, while drilling, can estimate the distance and provide a defined map of the boundaries while drilling, enabling the geosteering team to avoid the top or base of the sand.

Drilling began from the shoe with gamma ray from the previous run used to correlate with the offset well. This process provided a high level of confidence regarding the actual structural location of the wellbore in relation to the geology. A sump was planned at the beginning of the well. After drilling the shoe and landing the well, the interpretation was that the well was very near the bottom of the Kuparuk sand (Fig. 13), based on the negative geosignals, polarizing up-resistivity, and the distance-to-bed inversion calculations.

The well was steered upward toward the middle of the sand section in the event that any subseismic faults existed. During drilling, a small fault was crossed, which placed the wellbore higher in the section than expected. The sudden changes in geosignals and resistivity image indicated that a fault had been crossed. The fault was quickly characterized as being normal with a 5 ft throw. This placed the well slightly high in the section, but provided the geosteering team with confidence that the system was showing an accurate map of the reservoir in real time while drilling.

While drilling a long section, polarization effects on the resistivity image are readily apparent. Fig. 14 shows a strong polarization effect on the high side of the image, beginning at approximately 11,450 ft and continuing to 11,650 ft. This polarization event is associated with the Miluveach shale below, and the...
The geosignal associated with this event is clearly responding to the lower boundary.

The distance-to-bed boundary can also be estimated by using the depth of investigation of the tool responses and an understanding of how the tool responds to the boundary effect (Fig. 14). The strong polarization effects previously described affect the up and down tool response from an appreciable distance. The various curves with differing depths of investigation enable the operator to determine the distance to a bed boundary and whether or not the borehole actually crosses the boundary.

In Fig. 14, the 48-in. 500 kHz average phase resistivity response exhibits boundary effects from 11,550 ft to 11,600 ft. The 16-in. 2 MHz average phase resistivity does not. This result indicates that the tool was not near enough to the boundary for the 16-in. response to polarize, which puts the tool approximately 25-in. away from the boundary at its closest approach. The ADR™ tool was a great asset while drilling this well because it reduced the uncertainty associated with drilling the well and reduced the risk of exiting through the top or bottom of the reservoir. It also enabled the geosteering and geologist team to react more quickly and more aggressively than would be possible with a traditional steering string because the tool described the reservoir in greater detail, and could sense more deeply into the formation than a regular omni-resistivity tool.

Conclusion

Extended reach wells realize their full potential when geosteered to remain in the pay zone for the longest possible section. Their initial hydrocarbon production and their long-term recovery benefit from placing the well optimally in the reservoir. The preferred form of geosteering is proactive geosteering, whereby reservoir boundaries are identified long before they are intersected by the well path. Real-time informed decisions can then be made to control the direction of the well to an optimal position with respect to the detected boundary. Given the current technology in LWD, proactive geosteering is best performed by deep-reading wave resistivity sensors because they are capable of detecting boundaries remotely from the wellbore. Traditional non-azimuthal wave resistivity sensors, however, cannot determine whether the approaching boundary is located above the well, below the well, or to the side. As a result, real-time decisions may be adversely affected by this ambiguity. To remove the uncertainty, a new azimuthal deep wave resistivity sensor is recommended, especially for extended reach wells in complex geologies. The identification of the relative direction of the approaching boundary and estimates of its distance from the well enable educated real-time decisions to be made quickly to maintain the wellpath in the optimal section of the reservoir.

Geosteering with azimuthal deep resistivity is performed interactively by jointly interpreting several measurements and images. Azimuthal resistivity images, up-looking and down-looking resistivity logs, geosignal logs, and interpreted distance-to-bed boundary are all considered to make the best possible decision. Traditional wellbore images are also used to identify the formation traversed by the wellbore and to verify whether or not the well stays within the zone. The methods are illustrated on an actual Alaska well. Upper and lower boundaries are detected throughout, even after the well path crossed unexpectedly a subseismic fault.
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References


Overcoming Uncertainties through Advanced Real-Time Wellbore Positioning in Kuwait: A Success Story

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Abstract
Real-time multi-lateral wellbore positioning of horizontal wells for improved reservoir deliverability has been a revolutionary breakthrough worldwide. It has supported the efficient production of hydrocarbons from multiple thin layers within a reservoir to yield maximum recovery and to restrict water coning. Recent advances in real-time geosteering now enable, with even greater precision, successful targeting of “sweet spots” within a reservoir. These advances have the capability to open still more drainage volume for recovery of hydrocarbons.

Through successful teamwork from multidisciplinary professionals, numerous uncertainties and challenges were overcome using real-time geosteering techniques in conjunction with advanced logging-while-drilling (LWD) sensors and instrumented rotary steerable systems in Kuwait Oil Company’s Magwa field. For this purpose, pre-well modeling, real-time geosteering, advanced LWD sensors, including azimuthal deep resistivity (ADR™) sensor, an azimuthal lithodensity (ALD™) sensor, instrumented rotary steerable systems (RSS), and real-time operation (RTO) services were used. The historically anticipated production rate was surpassed through the optimized placement of this well.

The outcome of this particular dual-lateral well using advanced real-time geosteering technology has led to development plans for additional multi-lateral wells in Kuwait. They will be targeted to the highest porosity and permeability zones within the upper compartments of the reservoir while avoiding the adverse water coning effects of wells drilled vertically or in the massive sand. This paper reviews the teamwork and deployment of real-time geosteering operations, as well as new generation LWD and RSS sensors, used to successfully improve reservoir deliverability.

Introduction
Historically, in any oil reservoir after years of drilling hundreds of vertical wells directly into the predominant thick pay zone and producing as much as possible, water coning is inevitable and swift. At the same time, limitations on the spacing distance of wells in a field also became a factor to consider. With the advent of horizontal drilling multi-lateral wells that target thinner pay zones higher within a reservoir, precise wellbore placement has become the technology of choice to place the drain hole as high as possible away from the oil/water contact to prolong the production rate and life of a well. One of the major challenges of drilling such a well is the level of uncertainty in the geological and geophysical interpretations of the seismic and offset well data used to design and refine an optimum initial well plan. On the drilling engineering side of the operation, the goal is to deliver each hole section to the asset team as cost effectively and trouble free as possible. After the drilling of the build-up section of a well has begun, challenges include minimizing the dogleg severities along the wellpath and delivering a smooth wellbore to avoid complications encountered while running a casing or liner string. Perhaps the most critical challenge is to successfully manage the geological uncertainties through proactive geosteering and navigating the wellpath to remain within a thin layer reservoir. This success story describes the challenges and solutions on this dual-lateral well, from conception and planning to final delivery, through a real-time collaborative environment of many disciplines, technologies, and techniques.

Pre-Well Planning
The Greater Bugan field in southeastern Kuwait is one of the world’s largest and richest oil fields. This particular field is subdivided into the Magwa, Ahmadi, and Bugan sub-fields. The Magwa field (dome) is located on the northwest side of the Greater Bugan field (Fig. 1). Typically, conventional thinking was to drill vertical wells and produce from the thickest layer (B6) of the massive Bugan sand.

To demonstrate that this dual-lateral could target two very thin layers above the B6 layer, achieve an acceptable production rate, and increase the distance from the oil/water contact, the G&G team decided to target the B1b and B3 layers in the Magwa field (Fig. 2). Wireline log data from two offset wells (one near the heel of the well and one near the toe of the well) were used in conjunction with seismic data, structure maps, and area dip analyses. After extensive studying of the field and data from the surrounding wells and determining which upper layers would be targeted, a well plan was generated (Fig. 3 and Fig. 4).

Pre-Well Modeling
All data, including offset well logs, surveys, and dip surface of the B4 top, is loaded into a powerful and comprehensive real-time StrataSteer® 3D geosteering software solution to generate three-dimensional visualizations (Fig. 5 and Fig. 6), and the modeled synthetic log responses along the well path are displayed in a curtain plot format (Fig. 7 and Fig. 8).

The Challenge of Geological Uncertainty
Only two wells were available within close proximity of the target laterals and, through close analysis, it was found that the target layers in the offset well near the heel of the proposed laterals were 27 ft and 14 ft TVT, respectively. As the proposed lateral moves toward the offset well near the toe of the proposed lateral, the target layers are expected to gradually begin to thin and to become more unconsolidated and dirty. Because of the low seismic resolution and the apparent presence of localized dip changes near
the wellpath, the uncertainty of possible faulting and/or sub-seismic events along the wellpath is very high (Fig. 9 and Fig. 10).

**Tools and Sensors**

To manage uncertainties in real time during the drilling operation, a suite of advanced tools and services was used. Each component was selected for its particular strength and value in optimizing the well placement and evaluating the formation drilled. A brief listing of these tools, sensors, and services includes the following:

- Instrumented point-the-bit RSS, which is controlled in real time from the surface by a two-way communicating downlink system. This system includes an early warning of trajectory provided by an at-bit inclination sensor and unexpected formation changes provided by an azimuthal at-bit gamma sensor located 3 ft from the bit (Fig. 11).
- Azimuthal lithodensity sensor, which...
provides azimuthal data acquisition and obtains accurate density and Pe logs, even in enlarged boreholes or holes drilled with bi-center bits. Azimuthal log and image data also provides valuable information, such as accurate measurements of relative dip and formation structural dip for geosteering in high-angle wells (Fig. 12).

- Azimuthal deep resistivity sensor, which provides more than 2,000 unique measurements for precise wellbore placement and more accurate petrophysical analysis. Deep-reading (up to 18 ft), directional, and high-resolution images provide an early warning of approaching bed boundaries before the target zone is exited (Fig. 13).

Understanding the Azimuthal Resistivity Data
Before proceeding further, it is important to understand the data received from the ADR tool and its value in real-time geosteering decisions. The sensor operates at three different frequencies (2 MHz, 500 kHz, and 125 kHz) and consists of six coaxial transmitters and three tilted receivers. The transmitter-to-receiver distances span from 16 to 112 in. The receiver antennas are tilted 45 degrees with respect to the tool axis. By using multiple spacings and operating frequencies, the ADR sensor capitalizes on the high frequency and short spacing to map the near-wellbore properties. The longer spacing
and lower frequencies are used to measure the formation properties of the un-invaded zone. With operating frequencies of 2 MHz, 500 kHz, and 125 kHz, the sensor retains the advantages of high frequency data, such as greater accuracy in high resistivities and better vertical resolution, while gaining the advantages of the lower frequency measurements, including significantly greater depths of investigation. Consequently, the tool can sense resistivity boundaries around the borehole up to 18 ft away (Bittar 2000, 2002; Bittar et al. 2007). The sensor acquires a total of 36 resistivity logs that correspond to the various spacings and frequencies. Each of these resistivity logs is obtained 32 times per revolution of the bottomhole assembly.

Azimuthal Resistivity and Imaging
The tilting of the receiving antennas provides the azimuthal sensitivity of the ADR tool. As the tool rotates with the drillstring, resistivity measurements are acquired in 32 equally spaced sectors around the wellbore. In addition, one tilted receiving antenna was added at the maximum possible spacing to extend the lateral reach to a depth of first detection nominal of 18 ft. Instead of one non-azimuthal curve per sub array, the azimuthal sensor measures 32 azimuthal resistivities and derives the non-azimuthal counterpart (Bittar et al. 2007).

Polarization Effects
Because the ADR sensor is a propagation type resistivity tool, it produces eddy currents that emanate around the tool in a plane perpendicular to the tool’s axis. Consequently, when drilling
a vertical well in a homogeneous formation, the eddy current is not interrupted (Fig. 14). However, if the sensor approaches different resistivity layers at an angle, a charge buildup at the bed boundaries acts as a virtual secondary transmitter, which will increase the resistivity value measured at the boundary (Fig. 15).

Because the resistivity measurements are now obtained in 32 bins around the borehole, the top and bottom values (or any sector) can be isolated and displayed. As the sensor moves downward from a low resistivity formation into a high resistivity formation, the low-side reading displays the polarization horn effect, and as the sensor moves downward from a high resistivity zone to a low resistivity zone, the high-side reading displays the polarization effect. Concurrently, the 360° imaging around the borehole is subject to the same response physics; the bright spot phenomenon is also reflected (Chemali et al. 2009), as shown in (Fig. 16).

Geosignal and Imaging
One of the key measurements available from azimuthal deep resistivity is the geosignal. The concept behind the geosignal can be described as the differential measurement of phase and attenuation between two diametrically opposed bins (Bittar 2000, 2002) (Fig. 17). The geosignal is significantly more sensitive to approaching boundaries than the azimuthal resistivity. As a rule, the geosignal points from the more resistive formation to the less resistive (conductive) formation (Fig. 18). The bright spot on the geosignal image is clearly much more sensitive and visible than for azimuthal resistivity, and proves to be a very valuable tool in the proactive geosteering arsenal.

The geosignal is not a traditional resistivity measurement. The concept of the geosignal can be described as the differential measurement of phase and attenuation between two diametrically opposed bins (Bittar 2000, 2002), and is displayed in magnitude or decibels (dB). In the example below, the directional high-side (Bin 1) of the sensor reading is displayed as a blue line, and the directional low-side (Bin 17) of the sensor is displayed as a brown line. When the tool moves downward from a low resistivity zone into a high resistivity zone, the directional high-side (Bin 1) starts to increase (positive), and the directional low-side (Bin 17) starts to decrease (negative). This indicates there is an approaching bed boundary, and the lower resistivity (or higher conductive) zone is above the sensor. As the receiver moves across and exits below the bed boundary, the high-side and low-side geosignals reverse until both return to the zero baseline where the sensor is in a homogeneous formation where any bed boundary is too far away for the geosignal to detect it. Hence, when the geosignal moves from the zero base line to a positive magnitude, whether it is the high-side or low-side reading that is interpreted as the direction of the conductive bed. In comparison to the bright spot phenomenon from the resistivity image, there is no polarization horn effect per se, but more accurately the bright spot occurs in the direction of the more conductive bed (Fig. 19). Since conductivity is the inverse of resistivity, the bright spots of the two images passing through identical formations would be inversed as well. But for the sake of avoiding confusion between the interpretations of the two images, the geosteering specialist would typically invert the color palette of the geosignal image on the real-time curtain plot to reflect the
Drilling the Well
From the engineering perspective, this dual-lateral system called for drilling the lower leg (L0) first, then setting a whipstock just below the limestone marker (Maudud), and finally cutting a window and drilling the upper leg (L1). In drilling the buildup section down to casing point (top of B3) target layer, only gamma ray and conventional resistivity sensors were utilized without a rotary steerable system or geosteering service (Fig. 20).

For the first leg (L0), the resistivity curves selected for real-time transmission were 16-in. 500 kHz average, 32-in. 500 kHz, and 48-in. 500 kHz compensated phase resistivity top and bottom.
with imaging, and 82-in. 500 kHz uncompensated phase resistivity top and bottom with imaging. The geosignals chosen were short span 48-in. 500 kHz phase, long span 80-in. 500 kHz phase, and 96-in. 500 kHz phase. As drilling progressed, the up/down resistivity curves with the geosignal and image clearly revealed localized dip changes which made the original well plan unacceptable and quick decisions to divert from the well plan became necessary. By using proactive geosteering techniques in conjunction with real-time distance-to-bed boundary inversion supplied by the ADR sensor and StrataSteer 3D program, the wellbore was completed nearly 100% within a 5-ft TVT B3 pay zone (Fig. 21).

After drilling L0, a retrievable whipstock was set to kick off L1 just below the Mauddud limestone. The same real-time log curves were selected as used in L0. Some problems were encountered to achieve the required doglegs while landing the L1 in the top of the B1b layer, and the actual landing occurred 1 to 2 ft below the clean sand. The borehole angle was maintained at 90.5° from the landing point, aiming to drill back into the clean sand. A local apparent dip change of 1° was interpreted based on gamma responses and ADR log curves. Another rapid change in the apparent dip was evident from the ALD image after XXXXft MD, where the formation began to dip down almost 2°. At XXXXft MD, the clean sand was penetrated again with an inclination of approximately 89°. As the level of uncertainty began to increase, the geological and geophysical team began re-evaluating the seismic data and concluded that there were several faults near TD; a collaborative decision was made to cease drilling. Because the liner and subsequent perforation to be run in this lateral were planned to be oriented straight up, this lateral was overall considered a success (Fig 22).

Summary and Conclusion

When dealing with a high level of uncertainty within thin layered reservoirs, it is essential to use all of the tools and techniques available to proactively geosteer to maintain the wellbore in the target zone. Without the use of the instrumented rotary steerable system, with gamma ray, inclination at bit, and azimuthal lithodensity sensors (with high-resolution dip imaging), and the azimuthal deep resistivity tool (with up/down resistivity and geosignal), such a well would be practically impossible to drill and maintain nearly 100% reservoir contact. At the end of the day, the KOC drilling and engineering team, along with the G&G team on this project, rated this dual lateral as an overall success.

Figure 21. Complete curtain plot view of L0 within the StrataSteer 3D geosteering program.

Figure 22. Complete curtain plot view of L0 within the StrataSteer3D geosteering program.
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Field Evaluation of LWD Resistivity Logs in Highly Deviated and Horizontal Wells in Saudi Arabia

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Abstract

With the recent advancement of directional drilling technology and the use of rotary steerable systems, more deviated and horizontal wells are being drilled and evaluated around the world and especially in Saudi Arabia. In these complex reservoirs, logging-while-drilling (LWD) wave propagation technology allows accurate geosteering and well placement. Such a technology often exhibits boundary-related artifacts (horns) at formation boundaries between beds having different resistivities, particularly where the borehole penetrates formations at an angle. This makes resistivity interpretation difficult and creates a challenge for determining true formation resistivity that is essential for determining hydrocarbon saturation.

This paper presents a processing methodology for the elimination and reduction of horns and shoulder-bed effects. Logs processed using this method are more accurate and easier to interpret. This new technique solves the forward and inverse problems using a simplified approach. The forward problem is solved using a fast analytical technique that generates synthetic logs. The inverse problem is solved using the forward problem solution iteratively and minimizing a cost function that measures the discrepancy between the generated synthetic logs and the field data in a Gauss-Newton fashion.

Data processing and inversion of examples from fields in Saudi Arabia are presented to illustrate the usefulness of this methodology. For the examples, the values of formation resistivity and distance-to-bed boundaries are obtained. These results indicate that the processing method provides a reliable technique for evaluating the true formation resistivity of LWD logs in deviated and in horizontal wells for both well placement and formation evaluation.

Introduction

Geosteering is used to optimize the placement of wells in target formations; and accurate geosteering and well placement have been shown to enable dramatic increases in production. Among the variety of well placement techniques that are available, propagation resistivity is the one with the deepest sensitivity that also allows monitoring of the formation profile around the borehole.

Since the introduction of logging-while-drilling (LWD) resistivity service in the 1980s, there has been steady advancement in tool features and capability. The first LWD resistivity tool was introduced in 1983 with single frequency, single spacing, and single depth of investigation (Rodney et al. 1983). Multi-spacing, multi-frequency LWD resistivity tools were designed (Fredericks et al. 1989; Rodney et al. 1991; Bittar and Rodney 1994; Meyer 1995) and compensated LWD resistivity tools were introduced in 1989 (Clark et al. 1990; Strickland et al. 1994; Meyer et al. 1994). Most wave propagation tools followed the traditional design of coaxial transmitters and receivers. These traditional wave propagation tools were used for geosteering, but suffered from lack of azimuthal sensitivity which provides directional information needed to make a proactive geosteering decision. The advent of directional LWD in 2000 (Bittar 2000) allowed for more accurate well placement in more complex and hard to reach reservoirs (Bittar 2002; Li et al. 2003). This technology often exhibits boundary artifacts (horns) near boundaries between formations with differing resistivities, particularly in situations where the borehole penetrates the formations at an angle. These artifacts make interpretation difficult and create a challenge in the determination of true formation resistivity.

This paper presents a processing methodology to reduce or eliminate horns and shoulder-bed effects. The new technique solves the forward and inverse modeling problems using a simplified approach. The forward modeling problem is solved using a fast analytical technique that generates synthetic logs, and the inverse modeling problem consists of using the forward modeling solution iteratively. A numerical optimization algorithm is used to minimize a cost function that measures the discrepancy between the generated synthetic logs and the field data. Test results, as well as the data processing and inversion schemes that were used to create them, are presented.

Azimuthal Deep-Reading Resistivity

The Azimuthal Deep-Reading Resistivity (ADR™) tool is a multi-frequency, multi-spacing LWD resistivity tool with tilted antennas that give the tool its azimuthal sensitivity. The tool has six transmitters and three receivers with transmitter-to-receiver distances that span from 16 to 112 inches. The receiver antennas are tilted 45° with respect to the tool axis (Fig. 1). The tool operates at three different frequencies: 2 MHz, 500 kHz, and 125 kHz and has three compensated spacings; 16-in., 32-in., and 48-in. (Bittar et al. 2007). The multiple frequencies and spacings with the azimuthal measurement cover the entire range from shallow to very deep, allowing mapping
of formation resistivity from near the borehole to up to 20 feet away radially (Seifert et al. 2009 and 2011).

Resistivity readings are performed at 32 different angular positions or bins which are regularly spaced as shown in Fig. 2. Bin 1, referred to as the up bin, is that sector for which the angle between the coordinate vertical vector pointing upwards and the magnetic moment of the tilted receiver (vector normal to the surface of the receiver coil, using the right-hand convention for the winding direction of the coil) is minimum in a deviated well; similarly, bin 17, referred to as the down bin, is that sector for which this angle is maximum. In addition to the 32 azimuthal resistivity measurements, an average resistivity is produced from the measured 32-bin phase difference or attenuation and transforms them to phase and attenuation resistivity, respectively, through homogenous resistivity transforms. All azimuthal readings are equal if the measurements are not affected by adjacent layers. When the well approaches a layer boundary, azimuthal readings demonstrate characteristic differences that indicate a formation entrance or exit (Pitcher et al. 2011).

Traditional LWD wave propagation tools lack azimuthal sensitivity that provides directional information (Bittar et al. 2007). The computed response of a traditional LWD wave propagation tool in a 10 ohm-m formation that is bounded by two conductive beds of 1 ohm-m is shown in Fig. 3. As explained in Bittar et al. (2007) as the tool approaches the resistive bed from the top, the tool starts to read the high resistivity (polarization effect) and as the tool approaches the bottom conductive lower formation, the tool also starts to read high resistivity (similar polarization effect). The tool reading is the same as the tool approaches the conductive formation from the top or the bottom. This similarity comes from the lack of azimuthal sensitivity which consequently makes geosteering uncertain.

The computed response of the azimuthal deep-reading resistivity which was performed on the same model (Fig. 3) is shown in Fig. 4. Fig. 4a shows the well trajectory, Fig. 4b shows the high-side and low-side resistivities, and Fig. 4c shows the geosignal, directional geosteering signal (Bittar et al. 2007). The geosignal is a difference between measurements determined at opposite azimuthal orientations of the tool. The important point is that as the tool approaches the bottom formation the low-side resistivity (resistivity from bin 17) reads a much lower resistivity indicating that the tool is approaching a conductive bed from the bottom of the high resistivity zone. When the tool approaches the conductive bed from the top of the high resistivity zone, the high-side resistivity (resistivity from bin 0) reads a lower resistivity indicating that the tool is approaching the conductive zone from the top of the high resistivity zone. Similarly, the directional geosteering signal decreases as the tool approaches the conductive boundary from the bottom of the high resistivity zone and increases as the tool approaches the conductive boundary from the top of the high resistivity zone.

**Inversion Methodology**

Before drilling a target well, offset wells drilled in the vicinity can provide useful information such as expected resistivity and thickness of formation layers, which can be used as known parameters for a simple distance-to-boundary inversion.
Although the distance-to-boundary inversion can be a fast calculation, the accuracy of the inversion result is adversely affected if the resistivity values are different than the assumed value. A flexible inversion method without resistivity input was developed to consider such conditions.

The inversion method introduced here targets the solution of layer resistivities and boundary positions with a Gauss-Newton minimization scheme. For parametrization of formation unknowns, a three-layer model (Fig. 5) is used where $D_{up}$ is the distance to the up boundary and $D_{dn}$ is distance to the down boundary, with the tool assumed to be in the intermediate layer. The inversion method is based on an iterative 1D forward model that minimizes the difference between the raw measurement and the simulated response to obtain true formation parameters. The inversion is done independently at each logging point to avoid bias from past measurements. The dip angle is input as a fixed value.

The 1D forward modeling response of ADR can be expressed as $S$ while the formation parameter can be written as $X$,

where: $X \in \{ R_1, R_2, R_3, D_{up}, D_{dn} \}$;

and the cost function $C$ is defined as:

$$C = \| W_d \cdot (S - M) \| + \lambda \cdot |X - X_0|$$  \hspace{1cm} (1)

$M$ represents the measurement while $\| \cdot \|$ is the $L_2$ norm of the misfit vector. The inversion is designed to optimize the parameter vector $X$ for minimization of Eq. 1. The first part of the formula is the misfit between the simulation data and the field logs and the second part is the regularization term designed to stabilize the inversion which may include any a priori information. $X_0$ is the reference value of vector $X$ and $\lambda$ represents the degree of confidence of the reference value for each inverted parameter. The Gauss-Newton minimization approach is used for the numerical optimization procedure. Both resistivity and geosignal are required as input to the inversion to avoid ambiguities with the boundaries’ positions. $W_d$ is the weight matrix for the data used to influence the measurement contribution from each signal in the cost function.

The described inversion method can process simple formation structures with a single boundary which is a two-layer formation model. One-boundary inversion is known to handle complex cases better when only one shoulder layer provides the dominant effect on the response and the contribution of another layer is too weak to estimate its property (Donderici et al. 2012).

The inversion method is demonstrated in the following sections with two field test examples.

**Field Example 1**

The field recorded ADR geosignal and resistivity log data are shown in Fig. 6 for an interval of a well. Fig. 6a presents the up and down attenuation geosignal curves of 48-in., Ga48b1, and Ga48b17, for the operating frequency of 500 kHz. Fig. 6b displays the average, as well as the up and down phase resistivity curves of the 16-in. spacing at 500 kHz, Rp16b1, Rpavg16, and Rp16b17. Considerably large separations between up and down readings are observed in both the geosignal and resistivity values at x700 ft, x800 ft, x900 ft and x1,600 ft, which indicate the tool is approaching a boundary. The overlap of responses in some other sections indicates that the tool is far from the boundary or the logging point is at the electrical middle point, a point that has cancelling effects from the upper and lower layers.

The inversion method is used to obtain the resistivities of three layers and the distances to the up and down boundaries where the dip angle is assumed as 80° which is adequate for the point-by-point inversion performed here.
Fig. 7a shows the overall well placement in the formation. The well path is shown as the blue curve and the inverted up and down boundary position are shown in green and red, respectively. In this case, the well trajectory is in a thin resistive layer, approximately 5 feet thick. It approaches the top layer (layer 1 in the model of Fig. 5) at x700 ft and x900 ft and the bottom layer (layer 3 in the model of Fig. 5) at x800 ft and x1,400 ft. Fig. 7b shows the resistivity obtained from inversion. This confirms that the hosting layer is more resistive than the top and bottom layers.

Fig. 8 shows the comparison between raw responses and ADR simulation data with inverted formation parameters for verification and quality control purposes. In Fig. 8a, the raw average resistivities of 16-in., 32-in., and 48-in., Rpavg16, Rpavg32, and Rpavg48, respectively, are plotted and compared with the respective simulated data, Rpavg16s, Rpavg32s, and Rpavg48s. Fig. 8b includes four curves: the raw up attenuation geosignal of 48-in., Ga48b1, the down attenuation geosignal of 96-in., Ga96b1, and their respective simulated responses, Ga48b1s and Ga96b1s, with the final inverted resistivity and boundary position. There is good agreement among the measurements and simulation data for both the resistivity and geosignal responses.

**Field Example 2**

The field ADR geosignal and average resistivity log data are shown in Fig. 9 for a second well. The dip angle is assumed to be 80°, which is adequate for the point-by-point inversion performed here.

Fig. 9a shows the up and down attenuation geosignal curves of the 48-in. transmitter-receiver pair at 500 kHz, Ga48b1, and Ga48b17. The up, average, and down phase resistivity curves of the 16-in. transmitter-receiver pair at 500 kHz, Rp16b1, Rpavg16, and Rp16b17, are shown in Fig. 9b. Obvious separations between up and down readings are shown in the geosignal values in the middle of the section, which indicate the tool is near a boundary. The overlapping responses at the start and end of the section indicate that the tool is electrically far from the boundary (the boundary is beyond the depth of investigation of the tool and the measurement is very small or naught) or that the logging point is in the electrical middle point of the zone (where the electrical effect of the top and bottom boundaries of the hosting layer cancel each other). The resistivity plot shows three curves, Rp16b1, Rp16avg, and Rp16b17, all are over 10 ohm-m. The down resistivity reading, Rp16b17, reaches extremely large values up to thousands of ohm-m, which indicates the tool is very close to the boundary between two high-contrast layers. The up resistivity is higher than the down resistivity at the section from x020 ft to x080 ft and less than the down resistivity after x080 ft. This indicates that the well may have penetrated a layer boundary. The well is in the vicinity of a single boundary and ADR measurements are mainly affected by the two layers, therefore the one-boundary inversion method is suitable for handling this type of data.

Fig. 10 presents inversion results of the boundary position and resistivity values of the two layers with the single boundary inversion method. In Fig. 10a, the inverted boundary position plot, the well path, in blue, is plotted with the nearest formation boundary location, in green. The top layer is followed at 1 ft distances from x080 ft to x080 ft. An approach to the shoulder layer is observed from x020 ft to x080 ft and again briefly at x810 ft. The inversion results for the two resistivity layers, R_{top} and R_{sh}, for the interval from x080 ft to x800 ft are shown in Fig. 10b. R_{top} is the resistivity of the hosting layer in which the borehole well trajectory is moving, ranges from 30 to 100 ohm-m. The shoulder layer resistivity, R_{sh}, averages about 4 ohm-m.

In the interval between x020 ft and x080 ft and also at x810 ft, the opposite behavior is observed; the shoulder layer has a higher resistivity than the hosting layer, implying that the well trajectory crossed from one layer to the other during drilling. From the boundary and resistivity inversion results, the well trajectory is observed to be in a highly resistive formation. It exits this layer to enter the bottom low resistivity layer at x020 ft; then moves back up to the high resistivity layer at x080 ft; and finally it makes a transitory exit to the shale layer at x800 ft.
Conclusions

A new inversion method has been developed that allows the advanced interpretation of data from LWD propagation resistivity tools. The inversion method uses average, up, and down resistivities and geosignal measurements to locate and measure the resistivity of shoulder beds. This method can be used along with single- and dual-boundary formation models in appropriate scenarios. The new inversion method has been tested with field data from multiple wells. The accuracy of the inversion method was demonstrated by examination of the raw responses and by comparing the raw measurements with the simulated data from the inversion results. Overall, the new interpretation method is able to provide resistivity and distance-to-boundary of formation layers without prior geological knowledge. This lets us use LWD resistivity measurements for advanced formation evaluation and well geosteering.

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Fig. 9. Raw responses (Example 2). (a) Field geosignals from attenuation for the 48-in. transmitter-receiver distance at 500 kHz up bin 1 in blue, down bin 17 in green. (b) Phase resistivity for the 16-in. transmitter-receiver distance at 500 kHz frequency: up bin 1 in green, down bin 17 in red, and the average of all bins in blue.

Fig. 10. Inversion results for Example 2. (a) Nearest boundary position from inversion, in green, and well trajectory, in blue. (b) The inverted hosting layer resistivity, in blue, and the nearest shoulder layer resistivity, in green.

Fig. 11. Data comparison for Example 2. (a) The phase apparent resistivity for 16-in., 32-in. and 48-in. transmitter-receiver spacings for both raw and simulated data. (b) Comparison of geosignals from attenuation for 48-in. and 96-in. spacings for the up bin (1) and down bin (17), respectively, for raw and simulated data.

Fig. 11a displays a comparison between the raw measurements and the simulated data for the inversion result in Fig. 10. The curve names are similar to those in Example 1. Again, good agreement is observed in the comparison of the average resistivity at 16-in. As expected, the strong polarization effect induces larger discrepancies for the average resistivity of 32-in. and 48-in, where the sensitivity is weaker at high resistivity values. The comparison between the raw and simulated attenuation geosignals in Fig. 11b for the 48-in. up bin (1) and the 96-in. down bin (17) illustrates good match even for the 96-in. spacing that reads deeper into the medium in the downward direction and is included here for verification purposes.
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References


Application of High-Resolution LWD Borehole Images for Reservoir Characterization in Tectonically and Geologically Complex Reservoirs

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Abstract
The geology of Papua New Guinea is highly complex, resulting from intense tectonic activity that is attributable to its location at active tectonic plate boundaries. The rugged mountainous terrain makes it very difficult to acquire surface seismic and other geophysical data, which leads to a high degree of uncertainty in the structural geology influencing petroleum basins and fields. Even at moderate wellbore inclinations, a wide range of apparent dip angles and features can be encountered in these complex structures. Because of these uncertainties, a large component of most development drilling is still field appraisal.

High-resolution borehole images can identify the presence and orientation of key structural features, such as faults, fractures, bedding, unconformities, and borehole breakouts, which are indicators of the stress field around the borehole. These data are essential in geological mapping and geomechanical modeling.

Although high-resolution wireline electrical images could be acquired, the high borehole stresses caused rapid borehole deterioration and borehole instability issues, which often resulted in significantly reduced image data quality. The additional time required to obtain wireline image data also increased the probability that a borehole section would be lost before it could be cased.

Recent enhancements to a logging-while-drilling (LWD) imaging sensor have significantly increased its resolution. Although LWD images are not quite as sharp as some wireline electrical images, they provide a significant advantage of 360-degree coverage and improved acquisition conditions and logistics. In addition to the valuable structural information, important stratigraphic and textural details are visible, which promote a more complete understanding of the facies of the various formations. Micro-electrical images also enable the detailed mapping of fractures and breakouts that are valuable for geomechanical analysis and for updating the stress model. Conductive fractures, indicative of open fractures, can be identified and imaged in greater detail, sometimes pinpointing where a loss of drilling fluid has occurred. This capability enables completion designs that avoid perforating these features, which reduces the potential for gas or water coning.

Introduction
The exploration and development of oil and gas fields in Papua New Guinea encounters two types of challenges. The first set of challenges includes the rugged terrain and the difficult logistics in the highlands that make it hard and expensive to acquire geological and geophysical data. Surface seismic data are sparse. Outcrops are not easily accessed, and their geological relationship to the subsurface is not clear. Well costs often approach or exceed those of many conventional expensive offshore wells. The second set of challenges occur from the complexity of the geology. An extremely intricate fold belt structure with unexpected faults, folds, overturns, repeats, and inversions make it difficult to plan and successfully achieve the placement of the wells and development of the field. Structural information and geological models are key requirements in both the overburden section and the reservoir section. Even the development wells have a significant exploration and data gathering requirement (Bradey et al. 2008; Williams and Lund 2006).

Intense tectonic activity leads to significant downhole stresses; consequently, potentially serious wellbore stability problems can result in significant drilling issues, nonproductive time, and difficulties associated with acquiring wireline data. The characterization of borehole breakout and drilling-induced fractures is a key requirement in updating geomechanical models for the determination of wellbore stability.

Wireline imaging tools have historically been run, but the image quality is often poor as a result of hole conditions and borehole breakout. Tectonic stress and long formation exposure time between drilling and wireline logging cause the wellbore to deteriorate. A bad hole can sometimes result in difficulties with getting the tools to bottom, even when using drillpipe conveyance. In the worst case situations, imaging tools have been damaged and occasionally lost in the hole.

LWD imaging is now at a stage to provide high quality images for a wide variety of geological and geomechanical applications and can replace wireline logs. This paper describes the acquisition and interpretation of quality electrical images while drilling to help explain the subsurface geology and geomechanics in Papua New Guinea oil fields. Because the LWD electrical images are acquired before extensive hole breakouts occur, they exhibit a greater degree of sharpness and consistency.

Geological Setting
The Usano field is located along the trend and to the southeast of the Agogo and Iagifu-Hedinia (Kutubu) oil fields (Fig. 1). The structure consists of a hanging wall anticline that is separated from the Iagifu-Hedinia structure by an eastward-trending splay fault off the Hedinia thrust.

The hydrocarbon reservoir is the Early Cretaceous Toro sandstone, which consists of multiple cleaning-upward sequences generally deposited in
shoreface environments, with the paleoshoreline oriented in a northwest-southeast direction and a sediment feed from the southwest direction.

Although the Toro sandstone is of low porosity, usually 12 to 15%, the permeabilities are regularly measured in the hundreds of millidarcies (Bradey et al. 2008).

Locally, the Toro sandstone is divided into four units: Toro A, B Upper, B Lower, and C. The Toro A and B Lower units were deposited in mid-to-upper shoreface environments and generally display the better reservoir quality. The Toro C unit was deposited in a mid-to-lower shoreface environment and is usually regarded to be of good to moderate reservoir quality. The Toro B Upper unit was deposited in a lower shoreface to offshore environment; it is of variable quality. In a number of the nearby fields, the Toro B Upper unit is not generally considered to be of reservoir quality. However, in the Usano area, the reservoir quality of the Toro B Upper unit ranges from moderate to poor.

Overlying the Toro sandstone reservoir units are the Cretaceous siltstones, mudstones, and, occasional sandstone stringers of the lerus formation, which is unconformably overlain by the Oligocene-Miocene Darai limestone (Fig. 2).

LWD Imaging Tool
A recently developed 6 3/4-in. high-resolution azimuthally focused resistivity tool (AFR6) was used to acquire the images described in this paper.

Compensated Resistivity Measurement - The modeling of various configuration options for the

The high-resolution AFR6 was introduced in 2008 and is the successor of the standard resolution resistivity imager (Prammer et al. 2007).

The new sensor (Fig. 3) is based on the laterolog principle with radial and vertical focusing provided by the highly conductive tool body. The general concept for this type of resistivity measurement has been known for decades (Arps 1967; Gianzero et al. 1985; Gianzero et al. 1991); however, only the latest advances in modeling techniques and tool development technology has enabled it to reach its current optimal performance.
AFR tool indicated strong shoulder-bed effects for uncompensated sensors (Fig. 4). To mitigate the shoulder-bed effect, a compensated design was selected; it uses a folded configuration with three rows of sensors (Fig. 5) that provides compensation of all three transmitter-receiver spacings in a very compact tool.

**Sensor Resolution** - Given the optimal sensor design, the primary factors limiting achievable resolution include the standoff and sensor size (Fig. 6). Careful standoff control has been accomplished through the use of two stabilizers with dimensions that match the hole size and the nine pads holding the sensors.

The high-resolution sensors are optimized to create the best imaging resolution for standoffs of less than 0.2-in. and can resolve features that are spaced 0.5-in. apart.

The larger size receiver electrodes in the middle row of standard resolution sensors provide a balance between signal strength and resolution, enabling an accurate measurement of formation resistivity and the ability to resolve contrast in highly resistive formations of up to 20,000 ohm-m.

**Depth of Investigation and Depth of Electrical Image** - The three different transmitter-receiver spacings of 10-, 30-, and 50-in. enable three depths of investigation (DOI), in terms of radius. Following the industry accepted method, based on pseudo-geometric factor (Fig. 7), the DOI measured from the center of the wellbore ranges from 6.5-in. for the shallow reading to 15-in. for deep sensors.

Although the DOI characterizes the tool in terms of its range for resistivity measurement, it is not a suitable parameter for the determination of dip based on a resistivity image. Whether dips are picked visually, by a log analyst, or automatically, the placement of the sinusoid on the underlying image is based on the maximum gradient of conductivity. As a result, there is little difference in dips picked for different sensor spacings (Fig. 8). To avoid confusion and to differentiate a parameter suitable for dip picking from the traditional DOI, a new term was coined: Depth of Electrical Image (DOEI) (Bittar et al. 2008). For the sensors described in this article, the DOEI is approximately 0.5-in. measured from borehole wall (Fig. 9), regardless of the transmitter-receiver spacing.

**Data Quality Control** - The imaging resolution of the high-resolution AFR approaches that of wireline microresistivity tools and, in certain applications, the AFR images are easier to interpret as a result of 100% borehole coverage.
To assure good borehole coverage over a wide range of rate of penetration (ROP) and RPM conditions, the AFR tool is equipped with three buttons in every row. When measurements from the same row overlap, the data is averaged, which improves the signal to noise ratio. In parallel, the readings from three buttons are automatically compared to one another in a three-way voting system to detect hardware faults, which in addition to self-diagnostic and auto-calibration, are performed every few seconds.

For images, an additional level of quality control is provided by a comparison of images from three independently stored rows of buttons; two of these buttons have high resolution. This redundancy also helps to fill in potential image discontinuities during any intervals of slide drilling when the BHA is not rotating, and a complete azimuthal image cannot be acquired.

**Well and Logging Details**

In the Usano field well, the AFR6 tool was run in the 8 ½-in. hole section through the Ieru formation to the top of the Toro sandstone. At this point, the 7-in. liner was set, and drilling continued in the 6-in. hole, through the reservoir section to total depth (TD). The hole inclination began at 6° out of the 9 5/8 -in. casing shoe and was built to a maximum of 14° using a steerable mud motor to build angle. The 8 ½-in. section was drilled and logged in one run of approximately 1,000 m long; this section required four days to drill. The build rate and trajectory required slide drilling for 13% of the hole section; the remaining 87% of the hole section was drilled in rotary mode.

The BHA used for the 8 ½-in. section consisted of a steerable mud motor, directional sensor, AFR tool, GR, EWR™ multiple depth electromagnetic resistivity, and pressure-while-drilling (PWD) sensor. This configuration placed the middle row of the AFR tool 16 m behind the bit. The formation exposure time, which is the interval between when the bit cuts the rock and when it is logged, averaged approximately 1.5 hours for the AFR tool on this run.

A potassium chloride polymer water-based mud system was used in this hole section. The mud weight was 13 ppg, and the mud resistivity at downhole circulating temperatures averaged 0.08 ohm-m.

No wireline formation evaluation logs were run in the 8 ½-in. hole section.

All images presented in this paper are oriented with respect to the top of the hole because there was sufficient wellbore inclination to determine a reliable high side. The left and right sides of the image track represent the top of hole; the center of the track is the bottom of the hole. The tool was programmed to acquire and record data in 64 azimuthal bins at a sample rate of two seconds, resulting in very high memory data density of the entire 8 ½-in. section.

AFR images are calibrated resistivities and have units of ohm-m. Like wireline images, image processing software can be used to enhance the images by using a variety of filters to maximize contrast and detail for dip and fracture picking. The dynamic images that are presented use a moving window in which the data is normalized to maximize the use of the color palette and to enhance detail.

Although this paper discusses the use of a 6 ¾-in. resistivity imaging tool, 4 ¾-in. and 8-in. tools have been run in 6-in. and 12 ¼-in. holes respectively in other Oil Search wells in Papua New Guinea.

**Structural Dip Determination**

The primary reason for using LWD resistivity imaging in this well was to obtain structural dip information. This information is critical to the interpretation and update of the geological model in this structurally complex field.

Fig. 10 shows the structural cross section and trajectory of the well. Despite the relatively low angle of the well, a wide range of relative dips were encountered because of the complex faulted and folded structure.

The use of a high-resolution image improves the accuracy of dip picks. Any uncertainty in picking the height of the sinusoid results in errors in the
relative dip angle. Relative dip errors result in true dip errors, depending on the relative orientation of the borehole, and are increased at low dip angles. Bed boundaries are easily picked from the LWD image. Changes in dip orientation can indicate the location of faults that may not be directly discernible on the images themselves. The dip plot in Fig. 11 shows a clear change in bed orientation at the base of the Bawia formation. The dip-azimuth plot shown in Fig. 13 indicates the location of the fault (circled in red).

**Fig. 12** illustrates a minor fault located toward the base of the Upper Ieru formation in which the bed rotation is visible before the fault at xx04 m.

**Fine Bed Resolution and Texture**

Although the previous generation LWD resistivity imaging tools have sufficient resolution to adequately image bed boundaries to determine structural dip, higher azimuthal and axial resolution are necessary to adequately image very fine bedding (less than 1-in.) and reveal details of the formation texture suitable for sedimentological interpretation. In simple terms, as the imaging electrode size is reduced by a factor of n, the number of pixels is increased by a factor of $n^2$, which results in significant improvements in image quality.

**Fig. 14** shows a section of finely bedded claystones and siltstones at the top of the Juha formation at standard resolution. This image was acquired by the larger electrodes in the middle row of the AFR tool and has 32 bins of azimuthal resolution.

Although the thin beds are visible, the high-resolution image in **Fig. 15** shows much more detail, including calcite fragments (light spots) and traces of glauconite (dark spots).

**Fig. 16** provides an image from the base of the Bawia formation that appears as a homogenous claystone on standard logs. The high-resolution image shows the presence of bioturbation. Similar bioturbation is evident in cores taken in analogous lithology in other wells in the PNG highlands.

**Borehole Breakout**

Borehole breakout occurs when the tangential compressive stresses around the wellbore exceed the compressive strength of the rock. This normally results in failure in two zones that are 180 degrees apart. The location of the zones in which breakout has occurred, the azimuthal orientation, and the width of the breakout are all key data in determining the orientation and magnitude of the downhole stress field. This information is used to update the geomechanical model needed to evaluate wellbore stability.

If the downhole stresses and rock strength are such that breakout will occur, rock failure will begin as soon as the rock is cut by the bit. The enlargement of the breakout zones will typically increase with time. Several factors contribute to this enlargement, including chemical interaction of the rock with the drilling fluid, erosion from ongoing circulation of the drilling fluid, and possible mechanical effects as the rotating BHA and the drillstring pass the breakout zone.
**Figure 16.** Bioturbated claystone.

**Figure 17.** Borehole breakout four hours after drilling.

The resistive nodule in the center of the image locally alters the stress field and the resulting breakout around it.

This section was logged only 30 minutes after drilling because of a higher ROP and no delays associated with drillpipe connections between drilling and logging. Although the breakout is still clearly visible, it is not as well developed as the previous example, which had a longer exposure time. The average formation exposure time for the image logs over the entire 8 ½-in. section was 1.5 hrs.

Another interesting feature at the bottom of **Fig. 18** is a thin sandstone bed with a sinusoid feature indicating a thin closed fracture. This fracture is subvertical (true dip angle of 82°) and is striking east-west.

**Fractures**

Open fractures filled with conductive mud can be identified by lower resolution conductivity-seeking imaging tools. These tools will sense conductive features smaller than their electrode diameter, although the images will be blurry.

**Figure 18.** Borehole breakout 30 minutes after drilling.

**Figure 19.** Fractured finely bedded sequence.
The high resolution of the AFR tool is particularly valuable in imaging closed or resistive fractures.

Fig. 19 shows a 5 m section in the Juha formation. Conventional logs indicated that this siltstone was homogenous, but the high-resolution image reveals a very finely bedded sequence. These beds have very little resistivity contrast, but are clearly visible in the dynamically enhanced image. The formation dip is approximately 40 to 50° to the north.

The sequence was intersected by a consistent fracture set dipping at 50 to 60° to the southwest. These fractures have not displaced the fine beds and are tightly closed, displaying a slight halo effect.

Planar features, such as fractures crossing a circular borehole, produce the classic sinusoid shape. When the fracture is a curved surface, it appears as a distorted shape that is often referred to as a petal fracture (as in the petals of a flower). Petal fractures are drilling induced and typically occur in sets. Fig. 20 shows several petal fractures that were clearly imaged at the top of the Juha formation.

Fig. 21 shows where a thin section has spalled off the borehole wall in the Bawia formation. This stress induced event is terminated by the borehole cutting fracture above it.

Future Developments
In shallower hole sections, where lost circulation can be severe and result in decoding difficulties with LWD mud pulse telemetry, the use of electromagnetic (EM) telemetry can provide real-time LWD data and images.

Conclusions
Recent improvements in the resolution of an LWD resistivity imaging tool have yielded an image quality that approaches that of wireline electrical imaging tools. The LWD tool has the advantage of providing continuous azimuthal image coverage while rotating, with none of the gaps between pads that are a feature of wireline tools.

In highly stressed formations, borehole quality can rapidly deteriorate soon after drilling, which adversely affects wireline image quality; in more severe cases, it may result in an inability to convey the wireline tool to TD to acquire complete image data, or in tool damage.

A key benefit of imaging while drilling with an LWD tool is the elimination of the requirement for a separate wireline run, enabling casing to be run sooner after drilling is completed, and reducing risks associated with poor hole conditions. LWD image quality is typically high because of the better borehole conditions.

High-resolution quantitative LWD resistivity images are suitable for a wide range of geological and geomechanical applications, including characterization of structural and stratigraphic dip, fault identification, thin bed analysis, textural analysis, nature fracture characterization, location and orientation of borehole breakout, and drilling induced fractures for geomechanical model updates.
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