SPWLA 65th Annual Logging Symposium
Rio de Janeiro, Brazil, May 18–22, 2024
Technical Program

NOTE: Tentative Program: Selected papers listed below may not be in the order in which they will be presented. The final technical program may differ from that shown due to paper withdrawals. All technical sessions will be held at the **Sheraton Grand Rio Hotel & Resort***. Photography and video/audio recording of any kind are strictly prohibited in all areas, including technical sessions, workshops, and exhibition hall.*

ACOUSTICS TECHNOLOGY AND APPLICATIONS

A Case Study Utilizing Cost-Effective LWD Ultrasonic Imaging Technology in Unconventional Asset Development
Pingjun Guo, Brett Zastoupil, Laurin Musso, Steven Sowers, and Mohammed Bousaleh, ExxonMobil

The paper describes a case study utilizing a logging-while-drilling (LWD) acoustic imaging device to collect wellbore data and to achieve geoscience and drilling engineering objectives in lateral development wells in a tight oil play in the central US. A memory-based LWD ultrasonic logging tool was chosen for its compact size and low impact on bottomhole assembly (BHA) configuration, and versatility in water-based and oil-based drilling mud systems. The technology fits a critical cost structure aspect of key performance indicators in unconventional asset development and provides wireline equivalent borehole images for geoscience applications, including detection and characterization of structural features, bedding planes, and fractures, as well as for drilling engineering applications, including BHA performance evaluation and hole quality analysis. A pilot data collection program was planned and successfully executed in appraisal wells across the basin. Data analytics was carried out by an integrated team of geoscientists and drilling engineers leveraging knowledge from regional environments of deposition, seismic data, and historical drilling performance.

Effective acquisition strategies of acoustic image data sets were devised based on optimized ratios of drillpipe rotation speed (RPM) and rate of penetration (ROP) to maximize image resolution using either mud motors or rotary steerable systems (RSS) in lateral wellbores. Ultrasonic amplitudes and traveltimes were binned azimuthally to produce high-resolution image logs. Acoustic amplitude images were interpreted to map structural features such as folds, faults, and bed boundaries, which were not seismically resolvable. Fractures and drilling-induced artifacts were also interpreted. Analysis of traveltime image data enables thorough hole quality evaluation to identify key seating, spiral holes, and other drilling artifacts, which provide crucial insights to understanding drilling dynamics and drilling system performance.

Results from several lateral well examples will be shown to illustrate image acquisition planning, interpretation workflows, and fit-for-purpose geoscience and engineering applications. Shown in Fig. 1 is a curtain section of a lateral wellbore overlaid on the seismic cross section. The red square highlights the imaged depth interval in the curve section of the wellbore. The static and dynamic amplitude images and interpreted faults, beddings, and fractures are also shown in Fig. 1. The tadpole track in Fig. 1 indicates dips and azimuths corresponding to these features. The interpreted faults are consistent with mud loss drilling events. Shown in Fig. 2 are 16-bin traveltime-derived calipers in two 8.75-in. laterals drilled using a mud motor and an RSS in the same basin, respectively. The comparison of average, maximum, and minimum calipers demonstrates that the RSS-drilled wellbore shown in Fig. 2a has better hole quality than the mud-motor-drilled wellbore shown in Fig. 2b, in which spiral and under gauge features are observed. In summary, this pilot study demonstrates that a cost-effective and fit-for-purpose image data collection program utilizing a compact memory-based acoustic LWD tool provides valuable input for geoscience and drilling applications in unconventional asset development. Integrated with seismic data, ultrasonic images in appraisal wells enable accurate mapping of regional folds and faults and optimize well placement strategy in field development plans. Image-derived hole quality information provides guidance to optimize drilling system performance. From an operator's point of view, this technology has proved to be desirable for its excellent data quality at a competitive cost compared with existing LWD ultrasonic tools.

A Novel Method for Evaluating Hydraulic Fracturing Effect Utilizing Acoustic Logging
Siyi Li, Wenhui Chen, Hao Zhang, Liming Jiang, Xuekai Sun, Kun Shao, Hao Sun, Yanwei Zhao, and Peng Shi, Acoustic Research Center, China National Logging Corporation

With the development of unconventional reservoirs and continuous advancements in production technology, fracturing has emerged as a crucial method to enhance oil and gas production in tight reservoirs. Unconventional reservoirs typically possess low porosity and permeability, resulting in initially low productivity. Fracturing enables the creation of a fracture network within the reservoir, ultimately improving its permeability and recoverable potential, increasing oil and gas production. However, due to the unique geological characteristics and reservoir conditions of unconventional reservoirs, accurately assessing the effectiveness of fracturing using methods, such as well temperature logging, production fluid profile, and production dynamic, is challenging. Consequently, achieving a precise evaluation of the fracturing effect in unconventional reservoirs remained a technical problem in the exploration of unconventional reservoirs.

In the field of acoustic logging, the cross-dipole anisotropy inversion method has proven to be an intuitive and accurate approach for evaluating fracture height. However, the complex fractures geometry and the angle relative to the borehole have caused significant uncertainty in its evaluation, making it inefficient in unconventional applications. Thus, there remains a lack of practical and reliable methods for evaluating the hydraulic fracturing effect in unconventional reservoirs. Based on the dispersion analysis, Slowness Frequency Analysis (SFA), consisting of the projection of the dispersion curve on the slowness axis, can provide information about the formation characteristics such as lithology and fractures. A new method for rapid evaluation of the fracturing effect using array acoustic-logging data is proposed. The dispersion analysis method based on linear prediction theory is combined with hierarchical clustering, which considers both the inverted amplitude and slowness during the density-based clustering optimization. With less human intervention and a high degree of automation, high-precision SFA results before and after fracturing are effectively extracted.

Compared to traditional methods, the proposed method overcomes challenges such as soft formation and poor data quality after fracturing, enabling reliable extraction of high-resolution dispersion curves within three iterations. By intersecting the projection curve results before and after fracturing, a quantitative and accurate evaluation of the fracturing effect can be achieved. This technology has been successfully applied to the fracturing effect evaluation of shale and sandstone reservoirs in the western basins of China. It has enabled the accurate monitoring of hydraulic fracturing location and the scale of fracturing alteration, providing valuable technical support for evaluating the fracturing effect in unconventional reservoirs.

A Stabilized Real-Time Slowness Estimation Method for Compressional Waves by Using Kalman Filtering
Hao Sun, Chunhao Yu, Xuekai Sun, Liming Jiang, Husong Ling, Xianping Liu, and Siyi Li, China National Logging Corporation, CNPC

In acoustic logging, slowness estimation is always considered as a most essential and fundamental task because of its wide applications in lithology evaluation, rock mechanics analysis, and geological hazard forecasting. To reduce turnaround time for making efficient exploration and production decisions, there is a growing practical demand for stable real-time slowness analysis.

At present, the slowness time coherence (STC) method is widely used to analyze slowness characteristics from acoustic array waveforms. It usually requires fine-tuning of the parameters to ensure optimal performance. However, when employed for real-time slowness analysis, its ability to handle wave interferences, low signal-to-noise data, and noises has encountered remarkable challenges. Conventional peak-finding schemes often fail to accurately identify and pick slowness variations in such cases, resulting in considerable errors and unstable fluctuations in the derived slowness estimation.

This paper introduces a novel approach that combines Kalman filtering with the STC method to enhance real-time slowness estimation. Kalman filtering is used to update the optimal state of the system in real time, and it can significantly improve the stability of slowness picks, even in cases with poor signal-to-noise ratios and rapid slowness variations. In addition, the accuracy of slowness picks is further improved through an integrated peak-finding mechanism. In general, key parameters of Kalman filtering, such as process noise covariance matrix and observation noise covariance matrix, need to be appropriately specified before model construction. However, in the context of slowness estimation, obtaining these parameters can be challenging due to the uncertainties associated with stratigraphic changes. Consequently, this study proposes an automated method for parameter estimation to achieve acceptable results. The application of Kalman filtering is lightweight and thus poses little burden on data storage and calculation speed, leading to a much-reduced processing time within 20 milliseconds for each depth point.

This method has already been applied in many field cases of various lithologies and well types, such as openhole wells, cased wells, soft formations, and large boreholes (diameter exceeding 600 mm), which have verified its stability and time efficiency in dealing with the situation of gradual and sudden changes in different formations. As a result, this method provides a robust and reliable compressional wave slowness estimation, even when faced with challenges like poor signal-to-noise ratios and rapid slowness variations, making it a powerful tool for on-site data processing and evaluation.

Biot Coefficient From Sonic Logs With Laboratory Data Calibration – A Brazillian Presalt Field Case Study

Marcio José Morschbacher, Guilherme Fernandes Vasquez, Marcos Pozzato Figueiredo, Julio Cesar Ramos Justen, and Flavia de Oliveira Lima Falcao, Petrobras

The Biot or Biot-Willis coefficient is an important parameter for geomechanical models. It dictates the effective stress for rock compressibility. This parameter can be measured in the laboratory with careful geomechanical experiments, which can give accurate results. However, laboratory tests are relatively expensive because it demands sampling and time. Moreover, especially in oil exploration, rock sampling can be relatively scarce and biased. In this paper, we describe a case study where we measured the Biot coefficients of selected rock samples from a presalt Brazilian oil field. We also propose a method for estimating the Biot coefficient from sonic logs or, alternatively, from sonic, density, and compositional logs. The estimated Biot coefficient is virtually “continuous” through the logged interval and can be used to populate geomechanical models.

The Biot coefficient is given by one minus the ratio between solid matrix compressibility and drained rock compressibility. We measured the rock and the (inverse of the compressibility) with hydrostatic stress-strain experiments. We used cylindrical core samples of 1.5-in. diameter. We first jacketed the samples with a thin copper foil and then attached two pairs of strain gages on the jacket, one pair to measure the longitudinal deformation and the other to measure the radial deformation. The drained rock bulk modulus is measured with hydrostatic confining stress variation (according to a jigsaw function of time), with constant pore pressure, while the grain bulk modulus is measured with the same confining stress and the pore pressure, varying according to a jigsaw function. We calculate the bulk modulus by dividing the stress variation by the volumetric deformation in both cases. Our equipment (an Autolab 1000) allows the measurement of compressional and shear wave velocities. From the velocities, we can also estimate the drained rock bulk modulus using dry rock samples. We can refer to the modulus derived from the stress-strain experiments as “static modulus” and the modulus derived from elastic-wave velocities as “dynamic modulus.” To derive the “dynamic” Biot coefficient, we used the “dynamic modulus” and estimated the solid matrix modulus from rock composition derived from X-ray diffraction analysis, with the aid of reference mineral properties tables and the use of the Voigt-Reuss-Hill average.

We observed good and useful correlations between the Biot coefficient and some petrophysical and geophysical properties as well. For instance, the Biot coefficient increases with the porosity according to an approximately linear relation. It is also well correlated with the acoustic impedance, with the Biot coefficient decreasing with increasing acoustic impedance. The observed correlations suggest several possible ways of deriving the Biot coefficient from well logs. We did some tests and modeling, comparing them to previously conceived geomechanical models. We observed a very good correlation between the measured Biot coefficient and the “dynamic” Biot coefficient derived from elastic-wave velocity.

The figure depicts a comparison between Biot coefficient values derived from well logs (continuous line, with associated uncertainty) and those obtained from static laboratory experiments in the lab (blue squares). The “dynamic” Biot coefficient derived from several laboratory velocity measurements on core samples is also shown as green crosses.

Calibration of the Anisotropic Rock Physics Model and Its Petrophysics and Geomechanics Applications

Sergey Vorobiev, ITOIL-SV; Timur Zharnikov, Aramco Innovations; Vladimir Vorobyev, ITOIL-SV; Christopher Ayadiuno and Zainab Ibrahim, Saudi Aramco

We propose an anisotropy model that provides independent moduli for the vertical transverse isotropy (VTI) case and can be rotated to a monoclinic tilted anisotropy case. The model assumes that the anisotropy is caused by the sand and clay layers’ lamination or the lamination of contrasting elastic moduli of any other origin. The model calibration process includes stochastic inversion of the porosity, laminated and dispersed clay volume of the log-based acoustic impedance, and V_p/V_s ratio.

Splitting the total clay volume into dispersed and laminated parts is the basis of the model. Dispersed clay modeling is done using a combination of the Upper and Lower Hashin-Shtrikman bounds and Reuss bound. Laminated clay is incorporated using the Backus averaging technique. Once obtained, the VTI elastic moduli matrix can be rotated to the borehole frame using the rotation matrix. Six plots’ model calibration and three implemented independent methods of laminated and dispersed clay volume estimation techniques are presented and discussed. Stochastic inversion allows for the estimation of total porosity and dispersed and laminated clay volumes using log-based acoustic impedance and V_p/V_s ratio as an input. In hydrocarbon-bearing intervals, this technique requires to estimate hydrocarbon effect and to correct acoustic impedance and V_p/V_s ratio for the hydrocarbon presence. The correction is done by gradually increasing hydrocarbon saturation and estimating data point shifts until convergence between the model and corrected data has not been achieved.

The model has been tested on data sets from wells located in different parts of the world and from different depositional environments. The calibration process involves model fitting using six crossplots and three different methods of dispersed and laminated clay volume estimations. These three methods are Thomas-Stieber, shear moduli vs. total clay volume, and the inversion process. The model is sensitive to the total clay volume estimation and selection of the clay component elastic moduli. The hardness of the sand component can be adjusted by the cement in the pore space minimization process. The comparison of the three methods based on dispersed and laminated clay volumes allows to calibrate elastic moduli and total clay volume. A number of applications have been tested for the model. These applications include anisotropic elastic moduli estimates, Thomsen weak anisotropy parameters evaluation, inversion-based porosity and clay volume analysis, and saturation analysis. This paper presents a novel dispersed and laminated clay rock-physics model and its calibration technique. The model opens several opportunities for the acoustics anisotropy-based petrophysics and geomechanics tasks, including new applications for the quantitative seismic inversion (QI seismic).

Enhanced LWD Quadrupole Shear Processing Provided Reliable Shear for Reservoir Characterization: A Case Study From Deepwater Gulf of Mexico

Lei Wu and Alisa Kukharchuk, Baker Hughes; Gary Ostroff and Brian LeCompte, Murphy Oil

This case study discusses the crucial aspect of ensuring the quality of LWD acoustic data in diverse applications: (1) real-time top-of-cement (TOC) evaluation and (2) a novel approach to enhance the reliability of shear measurements.

In the deepwater Gulf of Mexico, operators in the oil and gas (O&G) sector face a stringent requirement for a TOC evaluation before advancing to the subsequent drilling phase. The conventional wireline (WL) cement evaluation necessitates a separate run, incurring additional rig time and costs. Logging-while-drilling (LWD) acoustic logging obtains high-confidence TOC information in real time and in larger casing sizes.

For the LWD environment, quadrupole mode is the standard for assessing shear in slow formations. The old centroid-phase-slowness-based dispersion correction method is prone to high uncertainty, particularly in faster formations. Often, it leads to gaps in shear data delivery. The introduction of the slowness-frequency-Coherence (SFC)-based parameterized inversion technique offers a more robust and comprehensive assessment of shear properties across varying formations.

To achieve real-time TOC detection, both the correlogram of high-frequency monopole and the coherence strength of casing mode are transmitted to the surface. It can be clearly observed that below the TOC, the casing mode weakens, and formations' arrivals become discernible in the correlogram.

Different from WL dipole, LWD quadrupole mode dispersion exhibits a distinctive behavior, approaching formation shear with a steep slope and experiencing significant attenuation at lower frequencies. Ensuring the reliability of shear data involves an automated identification of the “optimal” frequency range for quadrupole data at each depth level. This is followed by parameterized inversion, which minimizes the disparity between field data and modeled dispersion within that chosen frequency range. Through this process, shear slowness is extracted in varying formations.

The real-time TOC detection achieved through LWD monopole data demonstrates good agreement with post-processing and other WL cement bond measurements. This synergy not only streamlines the operation but also eliminates the need for a separate run for WL logging, providing significant time and cost savings for our clients.

Furthermore, the reliable shear data derived from the LWD quadrupole mode proves consistently accurate across diverse formations and in various wellbores. It is in agreement with refracted shear, where applicable. To enhance data quality control, the novel inverted method presents the discrepancies between field data and modeling phase slowness at each level.

Acoustic data serve as a vital indicator of the mechanical response within both the formation and cement bond in cased holes. It offers distinct advantages over gamma ray tracer methods in TOC and cement bond measurements.

The utilization of the newly developed inverted shear technique provides a comprehensive shear log across diverse formations. It can be used for alternative porosity sources due to its minimal fluid effects. Moreover, it proves valuable for geophysical and completion fracture modeling.

Formation Acoustic Properties Analysis Workflow Based on an Innovative Cement Evaluation Log Behind Multiple Casing Strings

J. Adam Donald, Kamaljeet Singh, and Erik Wielemaker, SLB; Amr Serry and Sultan Budebes, ADNOC

Sonic log data acquired behind casing are often viewed only as a last resort for formation evaluation because of the challenges related to cement quality and interference of the casing signal with the formation signals. Obtaining compressional and shear sonic log data through multiple casing strings and through tubing is even more difficult due to the presence of fluid within the annulus and the multiple wave modes propagating within the casing strings themselves. However, the advent of a combined ultrasonic-sonic frequency evaluation of dual-string cement has made it possible to obtain both compressional and shear formation signals through multiple casing strings. This is the first case study to present compressional and shear data obtained through dual and triple casing across overburden shale and carbonate formations in the Middle East region. The application was crucial for obtaining geomechanical data required for drilling sidetracks, which were at a higher angle than previously done in the field, and for evaluating the bond quality in the annulus for both the first and second casing strings.

Ultrasonic data analysis within first-string annulus material was conducted for fluid and solids and to determine the pipe-to-pipe standoff. Subsequently, the monopole and dipole sonic waveforms were analyzed to evaluate the second-string annulus cement quality. Through advanced dispersion analysis, the formation arrivals for the dipole shear signal were identified and separated from the casing-related arrivals. Filters, including wavelet filters, were applied to the monopole compressional arrivals to further identify the formation arrivals.

The results showed that the overburden section had three distinct intervals of cement quality, yet the formation compressional and shear were clearly identified through all logged sections. The first-string annulus had solids predominantly throughout the interval, which was not expected, and the quality of cement in the second-string annulus showed good cement, enough to also identify the formation arrivals. Inclinometry data were also available in this logging string, and dipole anisotropy was identified for stress orientation in certain formation intervals. In addition to the valuable evaluation of the formation acoustic properties, the new technology enables simultaneous evaluation of the presence of solids across two concentric casing strings.

High-Resolution Peripheral Imaging Around a Borehole With a Source-Independent TV-Constrained Full Waveform Inversion Approach

Zhilong Fang, School of Resources and Environment, University of Electronic Science and Technology of China; Meng Li, School of Earth Sciences and Engineering, Xi’an Shiyou University; Hua Wang, School of Resources and Environment, University of Electronic Science and Technology of China

Borehole reflection imaging (BRI) represents a geophysical method extensively employed within hydrogeology, petroleum exploration, and subsurface assessment. Through the examination of traveltimes and amplitudes of reflected seismic, sonic, or ultrasonic waves, BRI empowers geoscientists and engineers to generate finely detailed depictions of subsurface formations. These images unveil critical insights into sedimentary strata, fault lines, fractures, and reservoirs, and provide valuable data concerning composition, porosity, fluid content, and the broader geological attributes of the subterranean region surrounding a borehole well. BRI relies on the availability of a high-quality subsurface velocity model to produce top-notch images in the vicinity of the borehole well. Nevertheless, traditional techniques such as first-arrival traveltime tomography can only effectively reconstruct the velocity field in the immediate proximity of the borehole well, typically within a range of about one meter. When it comes to areas farther from the borehole, these conventional methods falter in generating a high-quality velocity model, thus creating a significant bottleneck in the imaging process.

In this study, our objective is to address the velocity modeling challenge in BRI using a total variation (TV)-constrained full waveform inversion (FWI) equipped with an on-the-fly source estimation approach. FWI is an advanced and potent geophysical imaging technique that has gained significant recognition in recent years and achieved remarkable success in seismic exploration. By harnessing the complete waveform information in the data, FWI can create high-resolution subsurface velocity structures at great depths. However, successful FWI implementation typically necessitates high signal-to-noise ratio (SNR) data and an accurate source function. Unfortunately, in BRI, reflections from the far field often exhibit very low SNR, and obtaining a high-quality source function can be challenging. To address this issue of noisy data, we propose a TV-constrained FWI framework, which effectively suppresses artifacts present in the data through TV constraints. Furthermore, we introduce an on-the-fly source estimation method using the variable projection method, eliminating the need for a precise source function dependency.

We performed numerical simulations to demonstrate the effectiveness of the proposed source-independent TV-FWI method (SITV-FWI) in noise reduction and source function robustness. Figure 1 presents the final comparison of the results obtained through conventional FWI and SITV-FWI. It is evident that conventional FWI struggles with noisy data and inaccuracies in the source function, whereas SITV-FWI excels in producing accurate results. In the upcoming stage, we will demonstrate the effectiveness of the proposed method by applying it to field data.

Looking for Producible Fractures on Different Scales
Fernando Gomes de Mello e Silva, Antonio Persio Silvestre, and Alexandre Kolisnyk, Petróleo Brasileiro S.A.

A dynamic flux model of a hydrocarbon reservoir relies on various geological and petrophysical parameters. Some inputs are related to the flow properties of the formation, such as matrix permeability and understanding the fracture environment. The sooner we acquire this knowledge, the better we can comprehend the field and mitigate production risks. However, the low seismic resolution poses challenges in identifying open fractures through geophysical analysis. The primary information about open fractures is obtained from image logging tools at the well scale, but its limited depth of investigation may not guarantee an accurate assessment of fluid flow potential fractures.

The objective of this study is to develop a methodology for identifying fluid flow potential fractures at both well and seismic scales. At the well scale, a combined interpretation of image and sonic logging tools, utilizing anisotropy and Stoneley information, enabled the construction of a “Potential Fluid Flow Fracture (PFFF)” curve. This upscaled curve was then used to guide the seismic analysis, employing a self-organizing map (SOM) approach with specific combinations of seismic attributes to identify fractured regions.

The methodology was applied to a group of wells in the same field. The results indicate a promising capability of the PFFF in distinguishing open fractures identified by image logging tools, which are deeper within the formation and exhibit good fluid mobility. This information can be valuable for future reservoir modeling related to fracturing. By utilizing the PFFF, it was possible to identify the contribution of open fractures in a formation flow test. Seismic results demonstrate a positive correlation between a combination of the best matching unit (BMU) and cluster number, representing identified regions on a two-dimensional (2D) Kohonen map and the PFFF. High and low values correspond to supposed fractured and nonfractured regions, respectively. These regions align with wells exhibiting varying levels of fractures. It is important to emphasize that all the results serve as good indications, but their certainty levels can be further enhanced through additional tests, new analyses, and the availability of more data in different fields.

Real-Time LWD Sonic Processing Enabled by Data-Driven Machine Learning
Lin Liang, Ting Lei, Yixin Wang, Matt Blyth, Michiko Hamada, and Naoki Sakiyama, SLB

Borehole sonic measurements play an indispensable role in the industry for formation evaluation and subsurface characterization. Various interpretation methods have been developed to derive essential formation properties, such as compressional and shear slowness, anisotropy, radial alteration, etc., from measured sonic waveforms. In general, these processing methods are physics-driven, meaning that repeated forward modeling is needed during an inversion process to match the acquired data to the modeled tool responses under different model assumptions, such as vertical transverse isotropy (VTI) or stress-induced anisotropy. The forward modeling can be accelerated using traditional look-up tables or more advanced techniques, such as neural network models, for either wireline or logging-while-drilling (LWD) tools. Methods with extensive physical models built in can enable automated processing over a wide range of tool operating envelopes while maintaining an expert-level interpretation. As a result, they can significantly reduce the time from data acquisition to interpretation delivery. However, a limitation of these methods lies in their dependence on high-performance computing platforms to achieve timely results. The data processing time could range from minutes to hours, contingent on the data volume being processed, because of the computationally intensive nature of the processing. This constrains the ability to deploy these methods at the wellsite and makes it extremely difficult to utilize them in the limited resources available in LWD downhole processing that would be required to deliver real-time data.

In this work, we develop a general framework for the interpretation of borehole sonic dispersion data using data-driven machine-learning approaches, with a specific emphasis on LWD tools, to underscore their advantages in real-time processing. We generate training data sets from two possible sources. First, the application of physics-driven automated solutions on field data processing will naturally create a substantial volume of labeled data, i.e., pairing dispersion data with dispersion modes labeled by those solutions. Second, we can also generate a large volume of synthetic dispersion data from known model configurations. These two types of labeled data complement each other, enabling us to train a neural network model applicable to various formation types. The training data set is preprocessed before being used for machine learning. For the data set generated from field data processing, a quality control (QC) threshold is chosen to filter out those data with low QC scores, and the slowness and frequency are normalized using predefined bounds. The normalized dispersion data are then converted into a two-dimensional (2D) image, serving as the input for the neural network, where the output is the dispersion curve. These models prove significantly more efficient at mapping dispersion data to modal dispersion compared to previous solutions.

The trained neural network model has been applied to LWD sonic quadrupole shear processing. Benchmarking against results from previous solutions shows excellent agreement while demonstrating a significant speedup by three orders of magnitude. This novel solution can complete data processing within seconds using just a single CPU. The trained model and processing algorithm can be further implemented on FPGA or ASIC for even better performance. This approach demands minimal computational resources, enabling real-time data processing at the wellsite or in downhole conditions. This feature is extremely attractive for LWD scenarios due to the comparatively limited processing capabilities in downhole tool electronics. It enables a more reliable, expanded, and automated interpretation of LWD quadrupole shear measurements in real time, aiding in optimizing the drilling process and mitigating risks, such as in real-time wellbore stability monitoring.

The Evaluation and Correction of Photoelectric Factor in the Presence of Large Standoff and Heavy Muds

Bair V. Banzarov, Andreas Vogt, and Nicklas Ritzmann, Baker Hughes

The photoelectric factor (Pe) is a key formation property that helps to identify and distinguish between formations of different lithologies. Pe is only a good measure of the rock matrix properties, as long standoff and borehole fluids do not overly influence the measurements. For wireline applications, in which instruments are pressed against the formation, invasion and mudcake are the main factors that influence the measurement. In contrast, logging-while-drilling (LWD) applications are more challenging due to the additional dynamic standoff behavior of sensors mounted in a rotating drillstring and potentially changing drilling fluid environments. For LWD borehole configurations, the main factors influencing the tool responses are standoff, mud weight, and mud Pe. The accuracy of the uncorrected Pe measurements can be acceptable only in configurations of in-gauge wellbores without the presence of high-gravity solids. In the presence of these factors, without adequate corrections, the Pe of the drilling fluids may significantly exceed the formation’s Pe, resulting in unreliable data being provided.

Radiation-transport simulations leveraging highly detailed instrument models based on computer-aided design (CAD) are utilized for an enhanced characterization of these wellbore effects. Stringent Monte Carlo simulations allow for detailed studies of perturbative effects on the measurement induced by changes in formation density, standoff, formation Pe, mud density, and mud Pe. A new azimuthal acoustic standoff service, targeting an operational temperature of up to 175°C and a pressure of up to 30 kpsi, is used to provide input for the Pe corrections. The integrated self-calibrating downhole measurement of the acoustic mud sound speed, independent of borehole size and shape, provides a crucial input to the caliper calculation and enables precise caliper measurements. The acoustic mud sound speed is affected by the dynamic mud properties, namely borehole fluid composition, pressure, and temperature. Thus, it is mandatory to account for dynamics and not simply use a static value as it has been in the past. The in-situ characterization of the density and sound speed of the annular mud under downhole conditions, together with a caliper measurement, delivers much more accurate borehole shape and fluid properties, benefiting the Pe correction and other borehole-affected measurements. We present an approach for standoff and mud properties corrections of the Pe measurements. The new algorithm is based on a multitude of radiation-transport simulation and experimental characterization results. The presented method yields improved evaluation of formation Pe in conditions of large standoff as well as elevated mud densities and absorption cross sections.

Simulation-based analysis of the tool responses allows the establishment of the main factors influencing the density tool responses to optimize the spectrum energy windows width and position for increased sensitivity to Pe. Furthermore, an algorithm is developed to map the measurements of spectral gamma ray response, caliper, mud Pe, and mud weight to formation Pe. Several methods are suited to evaluate mud Pe. Measurements of mud samples may directly provide Pe values. Alongside, retort analysis of the drilling fluid provides the chemical composition of the fluid, from which Pe can be calculated. Different methods were applied to evaluate the mud density and mud Pe, providing reliable input data for the Pe correction algorithm.

CASED-HOLE FORMATION EVALUATION AND RESERVOIR SURVEILLANCE

A Data-Driven Method for Formation Slowness Estimation Behind Casing

Xuekai Sun, Acoustic Research Center, China National Logging Corporation; Haochun Yu, Jun Zhou, and Jingqi Lin, China National Logging Corporation; Siyi Li, Acoustic Research Center, China National Logging Corporation; Hao Chen, China National Logging Corporation; Xianping Liu, Hao Sun, and Ran Zhang, Acoustic Research Center, China National Logging Corporation

As the number of cased boreholes is overwhelmingly large in each oil field, estimating slowness behind the steel casing is of practical significance in understanding and monitoring formation changes during production. In many cases (like coalbed methane), sonic logging can only be implemented after casing and cementing due to unstable borehole conditions.

Quite different from situations in open boreholes, the acoustic waveform acquired in cased boreholes is often contaminated by the casing waves, especially when the casing is poorly bonded with the formation. Because of its larger amplitude and longer time duration, the co-existing casing wave blends the borehole wavefield dramatically, making the extraction of formation slowness a challenging task. Many methods have been tested to solve the problem with limited success. Simulation-based methods can reconstruct missing slowness features of the formation, but they require much prior information about the borehole, mud, and cement as input. Meanwhile, present data-driven methods work to resolve the waveform interference in the transformed domain, in which the deliberately tuned time window and frequency seem critical.

This paper presents a new data-driven method to get formation slowness estimates behind casing, free of additional intervention. The proposed method first separates the casing waves from the original wavefield in the time domain by utilizing the constant slowness of the casing wave (i.e., 57 us/ft). Such an initial separation is essentially a slowness-filtering process, but it is prone to remove many useful features of formation waves, still causing considerable uncertainties for subsequent slowness analysis. Therefore, we developed a masking strategy to constrain the separation process with the aim of preserving more formation waves. Moreover, the proposed workflow can be combined with data-enhancing methods to further elevate post-separation S/N by exploring the data redundancy of acoustic waveforms. Processing the ultimately separated waveform using slowness-time-coherent (STC) or dispersion analysis reveals formation slowness characteristics behind the casing.

The proposed method has already been tested by synthetic examples and many field examples (in both vertical and horizontal wells), which verify its effectiveness and time efficiency in differentiating, separating, and enhancing weak formation signals behind the casing. It provides a new way of overcoming poor bonding effects and getting reliable estimates of the formation slowness. In particular, a challenging example in a horizontal well is presented, in which the compressional slowness of the formation is quite close to that of the steel casing. Because of the dominant casing waves, it is hard to discern formation compressional slowness from the original STC spectrum. As a result, the application of this new technique shows that it is capable of recovering and estimating formation slowness in spite of the severely blended borehole waves.

An Evaluation Cement Method Using Gamma-Gamma Density Imaging Logging in a Double Casing Well

Yiming Yu, Feng Zhang, Luyu Zhong, and Zhenghua Hu, School of Geoscience, China University of Petroleum (East China); Yuexiang Dai, CNPC Logging (CPL)

Deep wells, ultradeep wells, and some offshore oil wells are characterized by high pressure and high temperature, and their cementing casing is often prone to collapse and rupture. It is difficult to meet the exploration needs by using a single-layer casing cementing method, and nowadays, the double-layer casing cementing method has become more and more common, so the cementing quality evaluation method of double-layer casing has become particularly important. Nowadays, many scholars have analyzed the cement cementing condition of double-layer casing wells using acoustic amplitude and variable density logging, but there are few studies on the evaluation of the cementing quality of double-layer casing wells using nuclear logging methods.

Gamma rays have a weaker penetration ability to the medium, and their detection depth is shallow. Gamma rays are emitted from a radioactive source, and the number of particles that can return to the detector area after penetrating the double-layered casing is very small, so it is difficult to obtain information about the cementing quality of the outer casing. The detector counts are affected by the multilayered medium, so it is not easy to distinguish which layer of the inner and outer cement rings are actually missing. This is also the problem of using gamma density logging to study the cementing quality of double-layer casing. In this paper, a new type of multiprobe gamma imaging logging instrument has been designed; the radioactive source is the Cs-137, the proximity detector and the middle detector are composed of single probes, the distal detector is composed of six arrays of probes, and the detector window is composed of metal Be. The 0.662-MeV gamma rays emitted from the Cs-137 radioactive source penetrate through the borehole, inner casing, inner cement ring, outer cement ring, outer cement ring, inner and outer cement ring, and the inner and outer cement ring, and the outer casing, the outer cement ring, and the outer cement ring. casing, inner cement ring, outer cement ring, and ground layer, in which photoelectric and Compton effects occur. By recording the gamma flux distribution of different energies returned to different detectors, the response energy spectrum is obtained, and the total number of scattering counts of each detector in the energy window of 0.1 MeV-0.662 MeV is extracted to derive the logging value under this condition. The near detector has a shallow probing depth and mainly responds to the influence of the inner casing, the middle detector is mainly affected by the inner casing and the inner cement ring, and the far detector is mainly affected by the internal and external casing—the internal and external cement ring. Combining the measurements of the middle and far detectors can reflect the location of the missing layer of the cement ring, and the far detector consisting of six arrays of probes can respond to the missing cement ring in different directions and perform an imaging display, which can visualize the missing cement ring in different directions. In this paper, the diffusion equation of gamma rays under double-layer casing conditions is derived for the process of gamma particles interacting with the medium. Through numerical simulation methods, different inverse models are established to obtain the influence laws of the main control factors, such as inner and outer casing thickness, inner and outer cement ring density, and stratum density, on the count rate of the three detectors, and the response equations are established. The conditions of double-layer casing wells with different cementing conditions are set to verify the inversion effect, and the results show that the cementing quality can be accurately responded to.

Borehole Effect Correction in Pulsed-Neutron-Neutron Logging for Formation Capture Cross-Section Determination

Guofeng Yang, Wenzheng Peng, Hongfa Ye, Zhengyan Wang, Meng Chen, and Xiangjun Liu, School of Geoscience and Technology, Southwest Petroleum University

The pulsed-neutron logging technique has been widely used to monitor the oil and gas saturation in oilfield development, and pulsed-neutron-neutron (PNN) logging, as one of pulsed-neutron logging methods, uses He-3 detectors to detect the thermal neutron counts decay with time downhole and extract the capture cross section (sigma) of the formation from the thermal neutron time-decay spectrum to evaluate the reservoir saturation. However, variable borehole conditions and the difference between formation and borehole media will result in the uncertainty of the borehole effects on the derived formation sigma, which will hamper the calculation of reliable hydrocarbon saturation. For this purpose, a borehole effect adaptive correction method based on image feature detection was proposed. First, the capture cross sections extracted from different moments of the thermal neutron time-decay spectrum are calculated to form the sigma matrix, which is transformed into a gray image. After that, two kinds of image segmentation methods, OTSU and fuzzy OTSU method, which can provide double segmentation thresholds, are combined to eliminate the borehole effect utilizing the non-uniformity of image brightness distribution caused by the sigma difference between borehole fluid and formation and to extract the formation-dominated region from the image. Finally, the counts of the moments in the formation region were exponentially fitted to solve the formation sigma. Test pit experiments and Monte-Carlo-simulated cases were used to verify the applicability of the proposed method under different environmental conditions. The results showed that the calculated and intrinsic formation sigma have a good correlation after the borehole effect correction by the proposed method. Moreover, the interpretation results of PNN logging from actual field examples proved the proposed method’s performance by comparing it with the completion saturation.

Cement Bond and Corrosion Logging With Ultrasonic Phased-Array Transducer

Roel Van Os, Izabela Titton, Zheng Li, Hiroshi Hori, Patrick Girolami, Gilbert Tardivel, Orland Guedes, Gulnara Ishberdina, and Kamaljeet Singh, SLB

Pulse-echo ultrasonic measurement techniques are used in the oil and gas industry for imaging casing and tubing for cement bond and corrosion evaluation. Conventional downhole ultrasonic measurement tools typically consist of one or multiple ultrasonic transducers that probe the inner surface and are rotated to provide full azimuthal coverage. Measured signals are processed to deduce, among others, the thickness of the pipe, which can vary depending on the state of the corrosion, and the acoustic impedance behind the pipes, which can vary from high to low depending on cement quality from good to poor. Over the past decades, ultrasonic pulse-echo images have become the reference in the assessment of well integrity. One of the main points of development needed on such tools is the simplification of the architecture using a non-rotating device and the ability to perform controls on slim wells. Our proposal is to use an ultrasonic phased-array transducer and qualify such a device on a realistic configuration of well logging.

Phased-array pulse-echo methods are widely used in nondestructive testing and medical applications. In a typical operation, multiple elements are activated in a collaborative fashion to transmit and receive the ultrasonic waves. By introducing time delays among the elements, the ultrasonic beam can be shaped and directed onto regions of interest within the target. The main advantage of this technique for cased-hole imaging is its versatility, thanks to a multi-element transducer that is placed around the circumference of the tool. In this way, electronic scanning replaces the rotation that requires complex mechanical systems. Moreover, it improves the tool architecture by reducing the outer diameter of the tool and unlocks the possibility of deploying the tool on a monocable or slickline in memory mode. As such,

the tool will provide the capability to obtain azimuthal cement and corrosion quality starting from 3.5-in. casing/tubing, which was not available before.

A phased-array ultrasonic transducer has been integrated into an experimental prototype tool and has been used in the logging of a test well, representing a realistic logging environment. The well contains several types of cement and pipe thickness features that allow for characterizing the measurement response of the tool. The test well logs were compared with reference logs of a commercial tool. The results show good agreement between images obtained from the legacy and new phased-array sensors in tested conditions.

First-Ever Seven Pipe Corrosion Evaluation for Comprehensive Assessment of Pipe Integrity in Complex Well Completions

Ahmed E. Fouda, Junwen Dai, Huiwen Sheng, Mahmoud Saada, Neil Ostermann, and Sushovon Roy, Halliburton

Well completions typically encompass a series of multiple barriers that are crucial for supporting both production activities and protecting aquifers from contaminants. Monitoring the integrity of these completions is pivotal for ensuring the reliability of oil and gas production while safeguarding the environment. In scenarios involving diverse pressure gradients, geological complexities, or corrosive settings, the number of barriers may exceed five to enhance protection. This amplifies the intricacy of assessing pipe integrity within such wells. Even if tubing extraction is feasible, the presence of multiple permanent barriers exacerbates the challenge for current nondestructive testing methodologies to accurately assess metal loss within each barrier. This paper presents a comprehensive demonstration utilizing a full-scale fixture, highlighting the application of a multifrequency electromagnetic pipe inspection tool with multiple transmitter and receiver arrays to estimate the individual wall thicknesses of up to seven barriers. The fixture comprises seven pipes with outer diameters ranging from 2.875 to 24 in., featuring non-uniform machined defects to mimic realistic metal loss profiles induced by corrosion.

The tool operates on the principle of electromagnetic eddy currents, employing a configuration of multiple transmitting and receiving coil antennas arranged at variable spacings. It functions in a continuous-wave mode, spanning a range of frequencies. To enhance sensitivity towards outer pipes, the receiver coils are strategically positioned at increased distances from the transmitter, and low-frequency excitation is utilized. Preliminary feasibility analyses show the tool’s ability to discern measurements with sensitivity extending beyond the fifth outer pipe. A sophisticated data processing workflow is implemented, involving multizone calibration and model-based inversion. This intricate process facilitates the estimation of critical parameters such as the electrical conductivity, magnetic permeability of the tubulars, wall thickness, and eccentricity. Within the inversion process, a regularization term is introduced into the cost function to favor realistic solutions based on the direction of corrosion progression on the pipes, as inferred from the data. In addition, the effect of the noncircumferential corrosion profile is also analyzed numerically and experimentally.

The effectiveness of the tool in scenarios involving seven pipes is demonstrated by leveraging yard test data acquired from a full-scale fixture and real well field data. These tests provide empirical evidence supporting the tool’s precision in accurately determining the extent and position of corrosion within each individual barrier up to seven nested pipes.

This study represents a significant milestone as it showcases for the first time the capability of pipe inspection tools to precisely gauge the individual thicknesses of well completions comprising more than five pipes. This advancement eliminates the need to physically extract the tubing, providing a comprehensive evaluation of the integrity of well casings. The information gleaned from this tool offers valuable insights for understanding the causes of metal loss in well completions and facilitates proactive planning for remedial actions.

From Leak Path Detection to Quantitative Flow Profiling: The Exciting Journey of the Noise
Giuseppe Galli, Marco Pirrone, and Saida Machicote, Eni S.p.A.

Downhole well surveillance is considered, during an asset exploitation, a mainstay for the proper characterization of well completions and reservoir behavior. For these activities, specific tools have been developed to address wellbore integrity issues (e.g., sonic, ultrasonic, electromagnetic logs) and to depict downhole dynamics in injectors/producers (i.e., production logging). However, these standard techniques may have some limitations. For instance, cement logs provide an indirect static picture of the cement placement scenario and are not able to highlight fluid movement behind tubulars if present. On the other hand, production logging can only capture fluid flow inside the completion. Therefore, it is not possible to know the flow path from the reservoir towards the well, together with the active reservoir units. Advanced Noise Logging (ANL, operating in a wide frequency range) can be an elegant solution to overcome these limitations. This paper first shows how ANL is the key to addressing tricky wellbore and completion integrity issues and then introduces a novel methodology for the quantitative use of ANL by means of an in-house spectral analysis of the recorded data.

The versatility of ANL makes it suitable for multiple uses, and this is demonstrated here by several selected case histories involving different commercial tools. In detail, the measured signal (associated with particular fluid flow paths) is modeled to extract noise power amplitudes in specific frequency ranges and qualify fluid movements through the reservoir, cement channels/microannuli, pipes, and other completion elements (such as leaking valves and packers). For what concerns the presented wellbore integrity applications, the enhanced spectral analysis has provided a detailed noise classification and allowed a robust identification of the issue preparatory to possible remediation actions. Further, from a quantitative standpoint, modeling of ANL data in injection/production wells has been implemented to assess the relative flow rate in the borehole, the relative flow rate in the reservoir, and actual net pay. The latter are unique outcomes from ANL that are fundamental in challenging environments where standard production logging interpretations are not consistent or not exhaustive: the presence of asphaltenes, waxes and/or solids in the borehole, highly heterogeneous reservoirs, stimulated scenarios, and complex completions. It is worth mentioning that the reliability of such ANL-based dynamic characterization has been validated in standard scenarios with conventional production logging results (for more than 20 surveys).

The novelty of the approach relies on the key role played by the enhanced modeling of ANL data and the demonstrated versatility of the measurement, with applications spanning from unusual poor cement placement issues to completion microleaks. Moreover, the quantitative use of noise power amplitudes in selected frequency ranges is relatively new and puts ANL in a prime location for the dynamic characterization of very complex scenarios when the fluid flow path behavior near the wellbore is nontrivial.

Finally, the outcomes of the extensive ANL analysis represent a strategic input for production optimization activities, remedial jobs, workovers, well test interpretations, permeability estimations, and 3D dynamic reservoir modeling.

Managing a Unique Subsea Field Through Depressurization – An Update on the North Sea Machar Field After Five Years of Acquiring Casedhole Surveillance
Alexandra Love, Xiaogang Han, Thomas Harpley, and James Hoad, BP

Machar is a fractured, waterflooded chalk reservoir with oil recovery dominated by spontaneous imbibition. Due to productivity uncertainties, it has been subject to a phased development throughout its lifetime. In 2018, the field was moved into a final depressurization phase. With limited examples of depressurization in this type of field, a cased-hole surveillance program was developed to monitor the field’s response under blowdown conditions and provide inputs into the reservoir model for oil recovery predictions and well work opportunity progression. A variety of subsea well work campaigns have now been completed using light well intervention vessels. After 5 years of cased-hole surveillance acquisition, we reflect on how the field has responded, comment on the effectiveness of the original surveillance program, and discuss some of the challenges faced.

The surveillance program included the use of flow diagnostic logging, pulsed-neutron logging, acoustic logging, and multifinger caliper logging. The data acquired were used to:

- Measure three-phase matrix saturation measurement from pulsed-neutron tools using custom nuclear models
- Estimate critical gas saturation and update the full field model for oil recovery predictions
- Confirm three-phase inflow profile to inform gas shutoff, water shutoff, and plug removal opportunities
- Confirm the matrix and fracture interaction through data integration
- Monitor liner and tubing well integrity

Well selection, logging techniques, and intervention timing have broadly been successful, but new logging conditions have developed during blowdown. The pulsed-neutron tools required a detector sleeve to reduce the unnecessary reduction in sensitivity caused by a gas-filled borehole, and production logging tools often required a tractor to aid conveyance due to the increased lift forces associated with gas production. Core analysis and fine-scale modeling predicted a wide range of potential critical saturations, which in turn led to the full field reservoir model predicting a range of oil recoveries. Surveillance appears to indicate that critical gas saturation is heavily influenced by the presence of the fracture network. Flow diagnostic data was key in trials for two different types of gas shutoff (GSO) techniques. AICDs (inflow control devices) and straddle packers have been installed in Machar wells, increasing oil recovery. Well integrity logging has not highlighted any concerns. The author believes that Machar has reached the limit of what can be achieved with lightweight intervention vessels. Further rate adding well work and remedial work are likely to require a heavy-duty vessel or drilling rigs. It is key that the full field model be appropriately validated for use in future well work value estimations.

Novel Through-Tubing Casing Measurement With Azimuthal Sensitivity for Game-Changing Proactive Multi-Casing Corrosion Measurement
Matthew Gavin, Andrew Smith, Marc Ramirez, Sushant Dutta, Jun Zhang, Adam Ostrowski, and Negah Ardjmandpour, Baker Hughes; Johan Kverneland, TotalEnergies EP Norge

Corrosion monitoring of multi-casing systems is an integral part of well integrity management because it can provide timely information to operators for well intervention and workovers. Conventional multi-casing corrosion measurements investigate more than three concentric tubulars but only yield average non-azimuthal wall thickness measurements of each tubular. These lead to non-unique corrosion interpretation whereby a catastrophic failure in a small azimuthal region of the tubular may be indistinguishable from a minor metal loss that is circumferentially spread out. Hence, conventional multi-casing corrosion measurements can sometimes be limited to being used as a precursor to pulling the tubing and evaluating the casing again with single barrier evaluation services. A new transient electromagnetic sensor is presented that can provide azimuthal measurements of the casing through-tubing and can thereby help provide a better definition of conventional multi-casing corrosion measurements.

The new sensor follows the pulsed-eddy current diffusion principle by inducing time-decaying eddy currents in multiple concentric tubulars and measuring corresponding time-decaying voltages generated by outward-diffusing eddy currents. The sensor design evolved through multiple iterations involving modeling, simulation, rapid prototyping, and laboratory testing. In some instances, laboratory testing results were used to validate modeling results. In other instances, modeling was used as a tool to understand and explain interesting or unexpected behaviors and results observed in laboratory testing. Many tests were also performed to decouple two or more factors affecting the measurement. Basic interpretation workflows were developed as a means of quality control of test data, as well as to visualize and evaluate casing features measured through tubing.

The sensor comprises multiple coils oriented and operated differently from conventional multi-casing instruments. Simulation studies and experimental results are presented to delineate the sensor performance in terms of sensitivity to channel flaws, vertical resolution, depth of investigation, and azimuthal resolution. These measurements can also complement through tubing evaluation of cement behind casing in some cases by providing an independent assessment of metal features, while other measurements might provide sensitivity to both cement features and casing features. The novel sensor design has the potential to plug a critical gap in conventional downhole well integrity measurements during intervention or plug and abandonment, which in the present day only provide non-azimuthal multi-casing corrosion, thickness, and metal loss measurements.

Obtaining Johan Sverdrup Field Remaining Oil Saturation From a Variety of Logging Data
Brice Fortier, Hege Christin Widerøe, Margarete Kopal, and Eirik Berg, Equinor; Tom Bradley and Tor Eiane, Baker Hughes

Johan Sverdrup, situated on the Norwegian Continental Shelf, stands as the third largest oil field with a recoverable volume spanning approximately between 2.2 to 3.2 billion barrels of oil equivalent (BOE). The field came on production in October 2019. Given the reservoir's proximity to hydrostatic pressure, maintaining a consistent production pressure hinges on the concept of voidage replacement. The drainage strategy is seawater and produced water re-injection and, in a subsequent phase, water alternating gas (WAG) injection. The reservoir has excellent reservoir properties and multi-Darcy permeability. The ambition is to recover 70% of hydrocarbon in place; therefore, a comprehensive data acquisition strategy is in place to unravel and optimize reservoir drainage.

Dedicated to waterflooding observation, Well 16/2-D-22 plays a crucial role in this strategy. Drilling the well at the right time, a full suite of openhole logs has been acquired to fully characterize formation and fluids. The well has been completed with an unperforated cemented liner. Pulsed-neutron logging is conducted every 3 months to monitor waterfront evolution and evaluate in-situ water saturation (S_w).

Logging results allow us to evaluate the waterfront evolution pace while also confirming that waterflooding primarily occurs laterally along the most permeable layer. These observations are used in the reservoir and petro-elastic models and validate their overall accuracy.

Notably, the pulsed-neutron-derived water saturation within the flooded zone currently deviates from the estimated residual oil saturation obtained from openhole saturation evaluation and core experiments. To address this discrepancy, a comprehensive investigation has been undertaken, utilizing a multitude of data sources, including advanced nuclear magnetic resonance (NMR) techniques, verified by laboratory measurement. This investigation reveals that the residual of drilling oil-based mud, relatively deep into the borehole wall, may still influence pulsed neutron several years after drilling. It is believed that future well-log acquisitions will contribute significantly to our understanding of this phenomenon.

Overcoming Cased-Hole Logging Challenges to Assess Waterflood Conformance in Clair Ridge Segment 2B
Alexandra Love, Xiaogang Han, James Hoad, and Laurence Burchell, BP

Clair Ridge is the second phase of the Clair area development situated west of the Shetland Islands in the North Sea. The Devonian sandstone reservoir is relatively tight (around 10 md on average) and contains a relatively viscous 24 API oil that provides low oil flow rates unless the natural fracture network within the rock can be exploited for productivity and injectivity. Pressure support and oil sweep are achieved through LoSal (reduced salinity) injection, enabling recovery through a combination of viscous drive, gravity drainage, and imbibition, with the reduced salinity also limiting H_2S development. Long horizontal openhole wells are drilled to facilitate access to natural fractures. Each reservoir section is completed with a liner, swell packers for annular isolation, and timer inflow control valves (ICVs) to facilitate sequential startup. Communication between the liner and sandface is often limited to two to three ports per reservoir zone. While this completion style is necessary for a successful well, it does pose a challenge for cased-hole (CH) data acquisition as there is no direct access to the sandface. B16 (injector) and B15 (producer) are an injector-producer pair within segment 2B of the Clair ridge field. Good injector conformance was vital to oil recovery within the segment. Injection into each reservoir segment can be controlled using the ICVs (open/closed), but first, the well performance and swell packer integrity need to be confirmed using in-well surveillance.

Since the completion allows no direct access to the sandface, the team needed to get creative with logging techniques. An all-in-one logging string was used to assess flow diagnostics per reservoir zones, flow diagnostics at the sandface, three-phase matrix saturation, and swell packer integrity. The data were assessed in real time to allow for adjustments to downhole flow control. The string included traditional production logging tools, a pulsed-neutron tool, and passive acoustic tools to achieve these goals. A combination of CH interpretation techniques was used to understand well performance, well integrity, and matrix sweep. These included traditional production log analysis, water flow logging using oxygen activation, nuclear attribute response, acoustic analysis, and warm back analysis. The team also took one step further to integrate this data with the image logs, fracture presence, completion design, and well startup.

The CH surveillance data indicated that good injectivity conformance into the segment had been established and that no adjustments to the downhole flow control were required. The team was able to achieve insight into injectivity at the sandface and matrix sweep and confirm swell packer integrity. The surveillance also confirmed that the well startup methodology was successful in establishing conformance along a horizontal well with varying fracture intensity.

Successful Avoidance of Production Hazards From Subseismic Faults on a Multiple Horizontal Well Project in Permian Basin, Texas
Karim Sabaa, Baker Hughes; Derek Buster, Consultant; Amer Hanif, Ehsaan Nasir, and Eduardo Cazeneuve, Baker Hughes

For this case study, a Permian Basin operator deployed wireline dipole acoustic shear-wave imaging through five stacked cased-hole wells to determine the extent and orientation of subseismic, water-bearing faults prior to completing eight closely spaced horizontal wells. The operator encountered continuous and uncontrollable water flows throughout the drilling and casing of the first horizontal well on the multiwell pad. To minimize the risk of USD 50 million dollars in capital and potential long-term operating expenses associated with excessive water production, cased-hole logs were acquired in four additional horizontal wells' offline operations. Acoustic log data were recorded in five of the eight wells from two adjacent drilling pads. Reflected geologic features cutting across these wellbores were correlated with drill breaks, gas influxes, and changes in drilling mud properties, which helped identify the geohazard connecting the wells to this large water-bearing fault. The faulted zones were left uncompleted, and production results indicate the study well's performance exceeded that of neighboring wells in the field on a per-completed lateral foot basis.

Waveform acquisition was extended in time to expand the detection radius away from the wellbore. Advanced processing was performed to bring out acoustic reflections several tens of feet away from the wellbore. Images were exported in orthogonal planes and viewed in earth coordinates to correlate reflective features in a 3D visualization space between the adjacent boreholes.

Several important observations and conclusions are drawn from this study. Cement quality directly impacts formation wave coupling on monopole data; the lower-frequency dipole source did not generate significant casing ring and generated quality images through intervals with poor cement bonds. Direct logging measurement methods resolve observations on drilling reports, and indirect seismic methods lack the resolution required to guide an engineered completion design. Smaller, subseismic features are difficult to detect and cause significant operational issues. Operators can leverage higher-resolution log data to identify geologic events not resolved by surface-seismic data. Deep acoustic wave imaging presents a unique post-drill technology to interrogate, in either openhole or cased-hole conditions, the extent of intersecting and non-intersecting geological features proximal to the wellbore. Close well spacing may benefit total recovery; however, a single fault network can impact several wells. Thus, geohazard risk is compounded in tight-spacing developments.

Many operators avoid openhole evaluation services due to the rig-time costs and conveyance risks in horizontal sections. These risks are minimized by deploying acoustic tools in a cased-hole environment. Wireline tools can be rigged up from a crane and deployed through the horizontal section of a wireline tractor. In the drilled-but-uncompleted (DUC) stage of wells, the casing inside is clean, and operational risk is greatly reduced. The offline operation eliminates significant standby costs of a drilling rig or fracturing fleet.

Surpassing the Challenges of Cement Evaluation on Presalt Wells
Janio Cornelio, Kamaljeet Singh, and Emerson Rodrigues, SLB; Lorena Bicalho and Diego Brasil, Petrobras

The presalt reservoirs, located in deepwater offshore Brazil, boast vast oil and gas reserves and are characterized by very long and thick evaporite formations, mainly halite and anhydrites with thin layers of carnallite. The geomechanical properties of these layers impose several obstacles to the well construction activities, being one of the most critical to the well annulus barrier placement and the assessment of its integrity by direct verification using wireline logs. This study highlights the substantial effects encountered in acoustic measurements caused by salts' slowness and delves into the complexities of evaluating thick casings. Understanding and mitigating these challenges with proper logging tools are imperative for successful cement evaluation and ensuring the integrity of wellbore cement barriers in the presalt environment.

Sonic logging is widely used to assess cement quality by measuring the amplitude of the first casing reflection and analyzing its attenuation associated with the acoustic coupling between casing and cement; however, due to the similarity between casing and salt slowness, most of the time, a constructive interference on the first casing reflection can be observed, changing the peak amplitude, leading to inaccurate interpretations of cement bond. The analysis of the raw waveforms has been used to detect such phenomena and subside the impact attribution of the physical principle to be used as the main one for the barrier validation process.

Additionally, ultrasonic tools, designed to provide higher-resolution evaluation, and cement azimuthal distribution around the casing by traditional measurement of acoustic impedance are also susceptible to a similar interference, further complicating the assessment of cement bonding and properties. In this specific case, a special analysis of the raw waveform in the processing of the measurement windows and the addition of a new measurement named flexural wave attenuation mitigate the interference and provide a reliable cement bond evaluation.

Another peculiarity of saline formations is their mobility, obligating the operator to adopt the usage of extra-thick casings capable of withstanding the tensions associated with this property. The presence of thick casings (over 0.8 in. thick) adds to the complexity of cement evaluation as they attenuate the ultrasonic signals and may result in wrong measurements. To overcome this obstacle, the use of a more powerful ultrasonic transducer was adopted, allowing a better signal-to-noise ratio and a more accurate measurement.

In conclusion, successful cementing analysis in the presalt environment demands a comprehensive understanding of the influence of salt slowness on sonic and ultrasonic measurements, as well as the complications arising from thick casings. Innovative approaches, including advanced signal processing, extra measures, and improved tool designs, are vital for enhancing the accuracy and reliability of cement evaluation in this challenging geological and well-construction setting. Addressing these challenges is crucial for ensuring wellbore integrity and optimizing production efficiency in the presalt reservoirs.

The Technology of Magnetic-Pulse Flaw Detection-Thickness Measurement of Multistring Wells by the Transient Method

Gulnara Golovatskaya and Aleksandr Potapov, JSC Research and Production Enterprise VNIIGIS; Aleksandr Shumilov and Mingjun Xie, Perm State University

With an increase in the depth of oil and gas wells, the number of wells with four- and five-casing construction is increasing. At the same time, corrosion, cracks, and other types of defects in the columns severely impact the development of oil and gas wells. Therefore, it is necessary to develop existing magnetic-pulse methods in order to study the technical condition of casings in wells with complex designs.

Electromagnetic flaw detection-thickness measurement, based on the transient method, is the most effective in the study of multistring wells. Firstly, the measurement of the electromotive force of eddy currents decaying in time is carried out in the absence of a primary field, which makes it possible to reduce the spacing between the generator and measuring coils to zero (practically combine them), which significantly improves the vertical characteristic of the probe, allows the probe to register small defects. Secondly, in non-stationary mode, it is much easier to separate signals from the first, second, third, and subsequent pipes than in harmonic mode, increasing the accuracy of calculating the pipe-wall thickness and determining whether defects belong to a particular string.

To create an electromagnetic field in a multistring well cased with pipes of large diameter, generator coils are needed of a sufficiently large length, approximately equal to the diameter of the last string, which reduces the vertical resolution of the method. The use of multiprobe systems allows for an increase in the vertical resolution for the first and second strings since, for their study, shorter coils can be used than coils for the third and fourth strings. The measurement principle is based on recording the decay curves (DC) of eddy currents transient processes of J_v induced in four strings after the passage of a current pulse through generator coils that create a primary electromagnetic field H_0. The measuring system consists of three probes – short (S), medium (M) and long (L).

A supply current pulse of t duration is passed through all three generator coils of the S, M, and L probes. The generator coil of the S probe at time $t_1 < t/4$ is disconnected from the power supply, and the DC_S is registered by the measuring coil of the S probe. At time $t_2 > 3t_1$, the generator coil of the M probe is disconnected, and the DC_M is registered. After the passage of the current pulse – t through the generator coil of the L probe, DC_L is measured by the receiving coil of the long probe.

Figure 1 shows an example of wall thickness estimation of a multistring well, which includes tubing with a diameter of D = 89 mm (1), the first casing – D = 178 mm (2), the second casing – D = 245 mm (3), and the third casing – D = 324 mm (4), where SR, MR, LR are the decay curves of the short, medium, and long probes. The numerical indices are the time channels, and ML is the deviation of the thickness from the nominal value. In Interval 4, the destruction of the third string is confirmed by the calculation of the thickness T_3 = 0 mm±DT_3 and a sharp drop in the long probe DC amplitude. In Interval 5, the destruction in the second and third strings, T_2 = 0 mm±DT_2 and T_3 = 0 mm±DT_3, causes a sharp drop in the medium and long probes DC amplitude, where DT_3 and DT_2 are the absolute errors in determining the thickness of the corresponding strings.

Research results show that probes with different lengths make it possible to develop a method for determining destructions in multistring wells and an algorithm for calculating the thickness of strings by successively complicating interpretation models.

The Road Through Microannuli: Advanced Ultrasonic Log Analysis and Mechanistic Modeling for Leak Rate Quantification

Saida Machicote, Marco Pirrone, and Giuseppe Galli, Eni S.p.A.

Wellbore integrity is a principal concern for safe and efficient hydrocarbon production activities, as well as for fluid injection and storage purposes. In particular, defects in the well cement sheath cannot guarantee the hydraulic confinement of the desired fluid (e.g., reservoir hydrocarbons/water, injection/storage fluids) and can be the cause of undesired leakages and/or contaminations. This study aims to evaluate potential migrations of those species through possible pathways at the casing-cement interface by means of a quantitative use of sonic and ultrasonic logs integrated into an analytical flow model.

The proposed method considers cracks and wet microannuli (small fluid-filled gaps between casing and cement). This is because they can represent the main and sneaky preferential leak pathways in case of such wellbore integrity issues. The first step is the identification of the presence and location of a wet microannulus from sonic and ultrasonic log responses. Then, by exploiting different experiments/simulations found in selected literature, an ad-hoc relationship between acoustic impedance (by ultrasonic measurements) and microannulus thickness has been established through a dedicated analytical model suitable for various completions and cement property scenarios. This allows the proper estimation of microannulus thickness downhole using ultrasonic log data. Next, the obtained value is used as input to Poiseuille's equation for the final behind casing flow rate estimation. The model also relies on the pressure drop along the considered vertical portion; it is corrected for gravitational effects and strongly depends on the properties and behaviors of the leaking fluids. Several sensitivity analyses according to the referred input have been performed to evaluate the main model dependencies and, as a consequence, the associated uncertainty.

The defined analytical model leads to the quantification of the order of magnitude of possible leak flow rates behind casing (together with quantitative information from cement placement scenario, completion environment, and pressure/temperature regimes). This represents a fundamental input for subsequent wellbore integrity studies, remedial job activities, and/or proper mitigation actions. To date, the model has been applied to dozens of scenarios, including flow rate quantification of undesired water movement behind casing, gas leakages through casing shoe, and stimulation efficiency evaluation in the presence of possible communication between perforations. Selected case histories are presented to highlight the versatility of the developed methodology. Applications to underground storage projects (e.g., carbon dioxide) are also foreseen. The novelty of the approach relies on the downhole application of the microannulus thickness estimation from ultrasonic logging. This allows an effective leak rate quantification behind casing, and it opens the way to critical operative applications.

Through-Tubing Casing Deformation Inspection Based on Data-Driven Koopman Modeling and Ensemble Kalman Filter
Lijian Jiang, Linh Ho Manh, Qinshan Yang, Alexander Tarasov, Jinsong Zhao, Marvin Rourke, and Neil Sookram, GOWell; Mohamed Larbi Zeghlache, Saudi Aramco

Maintaining the integrity of wells in the oil and gas industry is of critical importance to ensure operational safety, environmental protection, and cost-effective production. One very important aspect in terms of the pipe integrity status in a well is casing deformation, which can be caused by formation swelling, formation subsidence, tectonic activity, salt creep, corrosion-induced issues, and thermal stresses. Some other conditions include completion defects or operation envelope. Evaluation of casing deformation is, therefore, an important requirement for well integrity management in these conditions; however, existing logging technologies require the removal of tubing in the well in order to evaluate the casing behind it. Tubing retrieval is a time-consuming and costly operation, and through-tubing casing inspection is a highly desired service for reducing these interventions and making casing deformation monitoring more accessible and routine. Nevertheless, through-tubing casing inspection with conventional electromagnetic technology encounters significant challenges in two principal areas. The first challenge is the tubing shielding effect, where only approximately 20% of the magnetic flux density reaches the casing area behind the tubing, resulting in little casing response to provide a reliable analysis. The second challenge is the tubing position inside the casing, which could be eccentric and variable along the zone of interest, introducing substantial uncertainties in the processing of the logging data.

A novel approach is proposed in this paper in which data-driven modeling and the ensemble Kalman filter are utilized to address these challenges. Recognizing the dynamic nature of the system and the influence of tubing shielding on the casing, an enhanced dynamic mode decomposition (DMD) based on Koopman operators was developed to manage these conditions. This approach treats the measurement process as a dynamic system, accounting for the casing deformation change within the well as a state change. In the ensemble Kalman filter, an observation model was built with the training data, which is acquired based on finite element simulation results. The simulation model considers different wellbore scenarios and logging conditions. The variable parameters include casing and tubing diameters, weights and location in the well, and tool position, along with electronic parameters. Moreover, the ensemble Kalman filter considers the physical constraints inherent in through-tubing casing inspection. This approach merges a Koopman-based dynamical system learning with physical constraints as an innovative approach to overcome the tubing shielding effect in order to effectively improve the accuracy of through-tubing casing inspection. Notably, the solution quantitatively estimates tubing eccentricity, allowing for the removal of its nonlinear effects, even in extreme cases of eccentricity where the tubing touches the casing.

The performance of this tool and the processing advancements have been validated both in laboratory setup and in the field across various well conditions and casing/tubing combinations. In the simulated through-tubing assessments, remarkable results of an estimated 5% deformation ratio accuracy for casing diameters up to 13.375 in. were achieved. Applications in the energy sector for such technique encompass through-tubing well integrity monitoring for production, injection, gas storage and geothermal wells, stuck pipe diagnostics without pipe manipulation, pipe eccentricity assessment for plug and abandonment operations, and tubing clamp orientation detection for control line positioning analysis. Measurements from this through-tubing casing deformation technology can be integrated with other conventional single or multibarrier pipe inspection logging tools, such as multifinger calipers and electromagnetic multipipe thickness tools, to provide a comprehensive pipe integrity evaluation solution.

Unlocking Reservoir Potential: Strategic Role of Saturation Logs in Cased Hole for Waterflooding Optimization

Patricio Zamora, SLB

The accelerated implementation of waterflooding projects in mature hydrocarbon fields, exemplified by Block 61 in Ecuador’s Oriente Basin, has presented formidable challenges in effective water management and uncovering untapped reservoir potential in secondary reservoirs. As hydrocarbon fields reach maturity, optimizing production becomes increasingly complex, necessitating innovative solutions for enhanced reservoir recovery. Traditional methodologies have proven inadequate in addressing the intricacies of waterflooding projects, especially in mineralogically diverse formations. This paper aims to showcase the strategic application of cased-hole saturation logs as a key tool to surmount these challenges and optimize waterflooding in mature fields.

This study integrates cased-hole saturation logs (CHSL) with injection logs (ILTs) to enhance understanding of horizontal and vertical sweep efficiency in waterflooding projects. Leveraging cutting-edge pulsed-neutron tools (PNT) technology, the study utilizes measurements of hydrocarbon saturation using total organic carbon (TOC), derived from spectroscopy of 19 capture elements, including carbon that can be converted to minerals and TOC, besides thermal neutron-porosity measurements. This advanced technology embedded in PNT provides a versatile and holistic tool for petrophysical evaluation and surveillance throughout the life cycle of the field.

Innovative procedures derived from this integration guide critical decisions in water shutoff intervals, the equilibrium of injection patterns, the calculation of secondary recovery factors, and the evaluation of reservoir abandonment or exploration in new areas. Furthermore, these procedures contribute to updating static dynamic models through continuous data feedback from pulsed-neutron tools.

The findings demonstrate that saturation logs independently provide hydrocarbon saturation regardless of formation salinity, addressing a crucial issue in waterflooding projects that employ injection water with varying salinity. This more than optimizes injection patterns; in combining with all the benefits of PNT, we can validate petrophysical evaluations, especially in areas with mineralogical heterogeneity. The integrated analysis, encompassing production behavior during the waterflooding stage, changes in water cut, and insights from PNT logs, highlights the instrumental role of saturation logs in risk mitigation for proposed wells and the identification of opportunities in secondary reservoirs.

Since 2019, over 60 saturation logs have been conducted, proving indispensable in managing waterflooding areas, formulating drilling plans, and ultimately achieving optimization with record production in a mature field with over 40 years of production. This integrated approach has resulted in a notable 15% reduction in water cuts and cost-effective rigless operations. The cumulative findings contribute significantly to a paradigm shift in waterflooding optimization, presenting a strategic tool for mature fields grappling with intricate production challenges.

CORE AND PVT – LOG VALIDATION AND RESERVOIR UNDERSTANDING

Core Cleaning for Wettability Restoration – How Clean Is Clean?

Hussain Al Qatari, Halliburton; Shouxiang (Mark) Ma, Aramco; Ahmed Hafez and Taha Okashah, Halliburton

Wettability is a fundamental property that affects other petrophysical properties related to multiphase fluids distribution and flow in porous media. To characterize reservoir wettability, low invasion preserved cores may be taken and characterized, but a much more common practice is to clean the cores and then age them in crude oil to restore reservoir wettability. In this process, core cleaning becomes critical. The main objective of this study is to assess the effectiveness of core cleaning for the purpose of wettability restoration.

Carbonate and clastic rocks were selected as prototypes in this study, and rock mineralogy was characterized by X-ray diffraction analysis (XRD) and X-ray fluorescence (XRF) tests. Testing fluids included two crude oils that were analyzed for saturates, aromatics, resins, and asphaltenes (SARA), as well as brines with different salinities. Solvents used for core cleaning include toluene, methanol, and xylene. The core cleaning methods tested are the conventional Soxhlet, as well as the flow-through method. Various traditional ways for assessing core cleanness by analyzing effluent solvents that are evaluated in this study are the tests of turbidity, UV light, and 10% silver nitrate. To address the question of how clean a rock is in terms of wettability, various wettability tests were conducted after rock samples were cleaned, including contact angle measurement and rate of spontaneous imbibition.

The results of this study illustrated that the conventional cleaning method using Soxhlet is generally effective for volumetric cleaning of pore spaces for measurement of porosity and permeability. This is especially true for high-quality rocks. However, completely cleaning rock pore surfaces is much more challenging and even difficult to evaluate unless a pore surface property-sensitive test such as the rate of spontaneous imbibition is used, although it is noted that this pore surface uncleanness does not affect pore volume measurement since a minuscule amount of polar hydrocarbon can alter the surface properties of a large surface area. Based on this study, flow-through cleaning is much more effective for pore surface cleaning for both carbonate and clastic rocks aged in a crude oil at connate water of different salinities, as shown in the side-by-side comparison of rate of spontaneous imbibition curves. The wettability impacted by the presence of dolomite and anhydrite was also captured. This is also qualitatively confirmed by contact angle measurements on treated rock slices.

A systematic study on core cleaning for wettability restoration addresses the issue that if cores are not completely cleaned, it may be difficult to restore wettability by subsequent aging.

Experimental Study on the Change of Resistivity of Synthetic Methane Hydrate Under Different Saturation and Clay Composition Conditions

Yin Lu, Wang Meng, and Zhu Jiangmei, China Oilfield Services Limited

The electric characteristics of a hydrate reservoir are the basis for evaluating porosity and saturation. Because drilling hydrate core samples are unstable at ambient temperature and pressure, and deep-sea drilling is very expensive and limited, simulation experiments on synthetic methane hydrate sediment samples in a laboratory are important tools for understanding the physical properties of marine gas hydrate sediments. This paper quantitatively analyzes the relationship between hydrate saturation and reservoir resistivity test experiments to study the formation and decomposition characteristics of hydrates of different saturation under different temperatures and clay content conditions, which is similar to the China Sea target area.

The experimental device used in this study is a self-designed and developed methane hydrate reactor. Methane hydrates were generated under low temperature and high-pressure conditions using high-purity methane gas and deionized water with natural sea sand simulated sediments with particle sizes of 0.18 ~ 0.25 mm and 0.425 ~ 0.85 mm. It is composed of three types of experiments: (1) variation characteristics of resistivity during the formation of methane hydrates under different conditions of temperature; (2) influence of different hydrate saturation on the resistivity during the formation process; (3) effect of clay components on the resistivity of methane hydrates.

In the process of hydrate formation, the general trend of resistivity changes under different hydrate saturation conditions is the same. The results show that: (1) When the methane hydrate saturation is low, the resistivity increases slowly, which is because the hydrate is first generated in the large pores. However, with the formation of a hydrate, the salt in the formation water is analyzed, and the mineralization of the formation water increases, which plays a role in resistance; (2) With the further increase of hydrate saturation, the resistivity increases significantly, and the growth rate is larger, which is because the hydrate gradually changes from dispersed type to cemented type, and starts to block the throat, resulting in the rapid increase of resistivity; (3) When the hydrate saturation is 20 to 60%, the resistivity of the hydrate is basically the same under the conditions of no clay and 10% clay, indicating that clay has no effect on the resistivity of hydrate. When the hydrate saturation is greater than 60%, the clay increases the resistivity of the hydrate to a certain extent. The accuracy of the experiment is verified in two wells in the South China Sea, answering questions about the low resistivity of the hydrate reservoir in the area.

Investigation of Wettability of Rock Components via Water Adsorption Isotherms
Isa Silveira de Araujo and Zoya Heidari, The University of Texas at Austin

Multiple conventional experimental methods are available to estimate wettability, such as contact angle measurements and imbibition tests on core samples. Although commonly used, the inconsistency in wettability assessment from these methods challenges the wettability quantification in mixed-wet rocks. Moreover, new reliable methods for wettability assessment in both homogeneous and heterogeneous surfaces and in core samples that have a variable range of wetting states are still needed. The concept of adsorption is fundamental to understanding fine-scale interactions between solids and fluids and potentially can be used for wettability assessment. For the first time, in this paper, we aim to conduct a systematic study on the relation between water adsorption and wettability. We experimentally compute water adsorption isotherms and perform sensitivity analysis on the impacts of (i) wettability levels, (ii) types of rock components, and (iii) concentration of mineral constituents on water adsorption capacity.

We synthetically change the wettability of pure quartz and calcite powders to obtain samples with variable wettability. Subsequently, we use part of the chemically treated powders to create pellets and measure the contact angle. On the remaining portion of the treated powders, adsorption isotherms are computed using a Dynamic Vapor Sorption Analyzer (DVS). We also obtain water adsorption isotherms on several types of pure minerals and organic components, including diverse clay types, quartz, calcite, feldspar, and kerogen. Finally, different minerals are mixed at distinct concentrations to evaluate the effect of composition on adsorption capacity.

Results demonstrated that Na-montmorillonite exhibits more water adsorption than the other minerals, reaching adsorption of 0.016 grams of water per square meter of Na-montmorillonite at 100% relative humidity. We also measured the water contact angle on the pure minerals and found that in these samples, the water droplet completely spreads, demonstrating a 0° contact angle. After chemically changing the wettability of quartz, a contact angle of 140° was obtained. The adsorption isotherms show that the change in wettability of quartz resulted in a decrease of 58% in the amount of water adsorbed at 80% relative humidity. A comparison of the water contact angle with adsorption isotherm measurements suggests that the isotherms are more sensitive to variations in wettability than the contact angle. Water adsorption on immature kerogen is found to be larger compared to the evaluated minerals. Results also suggested that the structure of kerogen is flexible and capable of large water uptake. Adsorption isotherms estimated on mixtures of minerals also proved that these measurements are extremely sensitive to small variations in the mineral composition. We proved that the fine-scale solid-fluid interfacial interactions can be quantified with adsorption isotherms and upscaled to wettability. The outcomes of this work also demonstrate the affinity of individual rock components to water. These results can potentially be used for further development of new methods for wettability estimates of mixed-wet rocks and rocks with complex mineral compositions.

Pore System Analysis in the Golfo San Jorge Basin: A Regional Overview
Juan Javier Fabiano, Alejandro D’odorico, and Sergio Bosco, YPF

Understanding the distribution of pore-throat radii within a reservoir is essential for assessing critical macroscopic properties like permeability, irreducible water saturation, and height of the transition zone. This type of knowledge is key for asset comparisons, identifying analogs, and providing insights beyond the reservoir scale. The Golfo San Jorge Basin is characterized by a predominantly fluvial sedimentary filling and a mixed influx of both clastic and pyroclastic debris, where several factors influence the configuration of pore systems.

Our study was grounded in an extensive compilation of samples having mercury injection capillary pressure within the Bajo Barreal Formation and its lateral equivalents. Mapping of pore-throat distributions at a basin scale led to the definition of different regions, each one of them characterized by distinctive pore system geometry. These variations were correlated to regional and semi-regional geological factors, including changes in the source areas of sediment supply, proximity to the paleo-magmatic arc, and local diagenetic processes associated with intrusive emplacement. To stress the importance of these changes in pore geometry, we integrated capillary pressure curves of both mercury injection and porous plate, conventional core analysis, detailed petrology descriptions, and statistical modeling, enabling a deeper understanding of the pore system.

The investigation yielded significant insights into reservoir behavior. The varied interplay of fluvial systems, pyroclastic materials, diagenetic processes, and tectonic forces significantly shapes pore geometries within the basin’s rock formations. Notably, we identified extensive zones characterized by high initial water saturation associated with the presence of high-permeability reservoirs. This research advances our understanding of Golfo San Jorge Basin’s reservoirs and holds potential implications for hydrocarbon exploration and recovery strategies. By combining rigorous methodologies with regional geological knowledge and employing statistical modeling and comprehensive data analysis, we pave the way for optimized reservoir management and enhanced hydrocarbon recovery practices, contributing to the sustainable utilization of valuable resources and advancements in energy production.

Practical Model for Estimating Reservoir Crude Oil/Water Interfacial Tension
Mohammed Fadhel Al-Hamad and Sharath Chandra Mahavadi, SLB; Shouxiang (Mark) Ma, Saudi Aramco; Wael Abdallah, SLB

Interfacial tension (IFT) of crude oil/water governs fluid distribution in porous media. IFT laboratory measurements require equilibrium conditions and, thus, are time consuming. Downhole IFT measurements are non-existent; therefore, reservoir simulators rely on empirical models to estimate IFT.

These models, however, don't account for the complex chemistry of crude oils and require oil properties that are not easily measured. In this paper, we propose a physics-based model accounting for crude chemistry to better estimate the oil/water IFT, even at downhole conditions.

Twenty-two crude oil samples obtained from different fields were studied in the laboratory. The pendant drop technique was used to measure the IFT of these samples with deionized (DI) water. The established empirical model, the Sutton model, was tested for its applicability in IFT estimation with a known and computed physical property—critical temperature (Tc). With a new model developed to estimate the Tc using laboratory measurable properties, such as density and viscosity, the performance of the modified Sutton model was tested for its accuracy.

The measured IFT values of the crude oils vs. deionized water were in the range between 21.1 to 27.7 mN/m. The traditional Sutton model overpredicted IFT by more than 100% compared to measurements. This is because the Sutton model was developed based on experimental data of pure hydrocarbons. The modified Sutton model, with the contribution of measurable properties—viscosity and density—improved the model performance as measured by the prediction error down to less than 6.5% while eliminating the need to provide the difficult-to-obtain critical temperature data for the samples. Moreover, the modified Sutton model is applicable under different environmental conditions including subsurface. The modified Sutton model also takes the downhole measurable parameters of density and viscosity to predict the IFT of crude oil with water, which makes it versatile to be used at downhole conditions to predict the IFT at in-situ and reservoir conditions.

The results and findings of this study open the opportunity to acquire the IFT of crude oils downhole at reservoir conditions using a newly developed model that depends on downhole measurable properties (density and viscosity). This is of great importance to reservoir engineers for accurate reservoir evaluations and estimations.

DATA ANALYTICS AND AUTOMATION IN WELL-CENTRIC GEOLOGIC EVALUATION

A Machine-Learning Approach to Predict and Characterize Evaporites for H_2 Storage in Salt Cavities

Perrine Baron, Emmanuel Caroli, and Sabine Delahaye, TotalEnergies; Alexandre Pichat, AKKODIS

In salt basins, anticipating the spatial repartition of intra-salt lithologies is a prerequisite for safe drilling operations and for the safe development of salt caverns. However, it requires compiling a large set of well data in the area of interest, and because of bad cuttings recovery during the drilling operation, the identification of lithologies is a cumbersome task done manually, combining well events, logs, and regional context. One challenge is thus to automate and standardize evaporite identification from log data.

Automated lithology identification from logs is a problem generally addressed for sedimentary lithologies (e.g., claystone, sandstone, etc.); it requires a sound understanding of wellbore context and log measurements. Recent applications with machine learning (ML) have shown that either classification or regression methods can deliver accurate results in some specific contexts. However, predictions can rapidly degrade in case of severe wellbore artifacts and for lithologies poorly represented in the training data set. Evaporites generally combine the two issues simultaneously with possibly poor borehole conditions and a large variety of lithologies seldomly distributed in the log database. Accordingly, ML classification with a high accuracy in evaporites is challenging and innovative.

A database was built with two famous areas for evaporites: the North Sea and Brazil. It includes a total of 743 wells having expert-validated evaporite lithology flags and a uniform set of conventional logs: density, neutron, gamma ray (GR), and compressional velocity logs. Log signatures were treated based on wellbore quality; data were filtered by thickness, distance to boundaries, and wellbore quality (diameter and rugosity). Then, considering that evaporites are pure nonporous lithologies, the Euclidian multidimensional distance and dispersion of the log data to the tabulated evaporite log coordinates were taken as a probabilistic quality indicator. Finally, due to some possible lithology mixtures (mainly halite and anhydrite), a few lithologies were reallocated, subdivided (sylvite split per GR and acoustic signature), or grouped (carnallite and bischofite). The final database contains eight salt lithology names (potassic salt, anhydrite, halite, sylvite, carnallite, polyhalite, bischofite, and tachyhydrite) covered by the same logs and having an equivalent clustering ratio. This represents approximately 10% of the initial data set for a total of 400,000 training points.

A large panel of ML clustering approaches was assessed with AutoML to select the best-performing and most robust model (random forest). The optimal combination of input logs was also tested and came, by order of importance, to density, GR, neutron, and compressional and shear velocities. In case a log was missing, a synthetic ML-derived version was used. After this exploration step, predictions were further improved with an average-standard deviation rescaling for each log and grid search for hyperparameters optimization. Since lithologies were quite imbalanced in the original data set, a class weight, inversely proportional to the cardinality of the target class, was applied for each depth frame. The model validation was performed with a set composed of entire wells having evaporite lithologies in the same frequency as the original raw data set. Finally, some post-processing was performed on outputs to reallocate some classes, which increased the prediction accuracy.

The full workflow was applied to the North Sea and Brazilian sectors, and the model could predict with high accuracy:

- Anhydrite – Halite > 90%
- Sylvite – Carnallite > 70%

The results were used to define intra-salt lithology distribution, characterize evaporite acoustic properties, and initialize seismic models. The whole study cycle could be achieved thanks to the automation brought by the ML steps, which, in return, allowed an exhaustive use of the well data and ensured interpretation consistency all over the area.

An Automatic Approach for Core-To-Log Depth Match in Presalt Carbonate Reservoirs
Adna Grazielly Paz de Vasconcelos, Danilo Jotta Ariza Ferreira, Rodrigo Bittencourt de Aguiar, Luciana Velasco Medani, Giovanna da Fraga Carneiro, and Lin Liang, SLB

This study introduces an automated approach for aligning core depths with well logs. Core samples can be a very accurate and reliable source of petrophysical measurements. Conversely, well logs present a higher level of uncertainty but offer the advantage of covering a larger portion of the lithological formation when compared to cores. These two sources of information can be combined to improve formation evaluation for a more reliable formation evaluation.

Core and logs are acquired using different tools and at different times, requiring core depths to be checked and adjusted to the logs. This process is usually tedious, time consuming, and prone to human bias and errors. Furthermore, the conventional adjustment approach is usually based on gamma ray measurements, which may limit its applicability to carbonate rocks, as gamma ray variations in carbonates are commonly not very representative of formation heterogeneity. This complicates the manual depth-matching process, especially for the presalt carbonate reservoirs in Brazil. Therefore, this study presents a method for automating core-to-log depth matching by comparing petrophysical properties obtained through laboratory analysis of core data with the corresponding well logs.

The depth-matching algorithm was developed using statistical methods and consists of three main steps. First, a data preprocessing step normalizes the inputs with the Z-score so that the algorithm can handle different properties, measured in different resolutions, depending on the desired scenario.

The second step involves removing outliers to mitigate scale inconsistencies between core and log data based on their standard deviation. The cutoffs retain approximately 95% of the data, assuming they follows a normal distribution. The final and crucial step suggests the depth shift of core samples based on the maximum correlation between the core and log values, quantified by the normalized cross-correlation (NCC) metric.

The NCC measures the similarity between two signals by calculating the cross correlation between them, which is then normalized to account for differences in their mean and standard deviation. Using the NCC as a metric for core-to-log correlation simplifies implementation and interpretation and provides a quantitative measure of the correlation between the core and log data, enabling an objective assessment of alignment quality.

In addition, for those cases where core plugs are extracted from whole core samples, the algorithm can apply the same rule to each group of plug samples that belong to the same whole core. With this, core plugs derived from the same whole core are shifted together, minimizing depth errors that may arise from core fragmentation, especially in unconsolidated formations or highly porous or fractured carbonate environments.

For validation purposes, we applied this innovative method to a challenging Brazilian presalt field, using neutron porosity, nuclear magnetic resonance, and bulk density as reference logs for depth-matching core porosity. Core sample depths from nine different wells were adjusted. In this case study, core porosity values could vary by up to 15% at the same depth, highlighting the value of the data preprocessing and outlier removal steps. Following this approach, wells with a core position delta of less than 2.0 m showed an 80% improvement in correlation compared to the manual matching process. For wells with a core position delta larger than 2.0 m, the improvement in correlation was 150%.

Compared to manual matching, the developed solution has been proven to enhance the value of core samples for petrophysical models, improve overall accuracy, especially for carbonate reservoirs, and reduce the time and effort required from hours to minutes. Finally, the method has potential application to other scenarios using the same gamma ray measurements, with the advantage of being an automated approach.

An Autonomous Workflow to Evaluate Acoustic-Logging Waveform Quality
Gengxiao Yang and Hua Wang, University of Electronic Science and Technology of China

Quality control is always a critical issue for logging data applications. For example, if bad logging data are used, the interpreters would give inaccurate assessments of borehole conditions, which will result in subsequent erroneous decisions. Nowadays, as machine-learning methods are gradually being explored and applied in the oil and gas field, experts usually spend an enormous amount of time picking or selecting high-quality data as labels to train machine-learning models. Although we can use data-driven methods to improve the efficiency of the logging data quality assessment, sophisticated evaluation approaches are needed for advanced logging, such as full waveform acoustic logging, which needs an expert with rich experience. However, senior experts on acoustic logging are always in short supply because the acoustic-logging tool is becoming more and more advanced, and the acquired data are growing. High-efficiency logging data assessments become increasingly challenging. Therefore, it is of paramount importance to develop an efficient automated data quality assessment workflow.

This paper primarily presents a workflow for waveform quality assessment focusing on full waveform in ultrasonic and sonic logging. We first utilize wavelet transforms to analyze the time-frequency characteristics of synthetic ultrasonic pulse-echo waveforms and then define a feature parameter in the time-frequency domain to describe the quality of the ultrasonic waveform. For array acoustic logging, since there is continuity and similarity in depth for the individual waveform, we first employ a singular value decomposition to decompose the waveform matrix and then select some singular values to reconstruct the waveform. We identify abnormal waveforms by detecting outliers in the correlation coefficients between the original and reconstructed waveforms. In addition, we combine the time-slowness coherence method, spectral similarity between waveform arrays, and signal dominant frequency detection to jointly evaluate the quality of array waveforms. Our anomaly detection strategy is that the waveform will be marked as abnormity when one or more of the above four methods detect abnormity. We also provide the abnormality rate of waveforms in each interval for the whole logging depth. In order to visualize the results of the waveform quality assessment, we set thresholds to divide the abnormality rate into four levels and mark them with different colors as a reference for interpreters.

We applied the algorithms and data quality visualization scheme to field acoustic-logging data. The results indicate that the data quality assessment workflow can detect the majority of abnormal waveforms by setting proper parameters. According to different colors, we can easily judge the level of data quality in a certain depth interval.

Cascaded Machine Learning in NMR: Unveiling a Continuous Grain-Size Distribution Approach for Tackling Sand Production Challenges

Muhamad Saiful Hakimi Daud, SLB; Seyed Mehdi Tabatabai, PETRONAS

The management of sand production in mature siliciclastic reservoirs is a recurring challenge, primarily stemming from the declining reservoir pressure as hydrocarbons are extracted over time. This phenomenon induces subsidence and compaction of reservoir rocks, which, in turn, can alter their strength and mechanical properties, leading to sand production issues. The effective and safe management of the solids produced presents a considerable challenge for operators.

One well-established approach to mitigate sand production is the implementation of sand control mechanisms at the source. While this strategy has been widely adopted in various locations, its success depends heavily on the optimal design of these mechanisms. Critical to this design is the accurate characterization of the grain-size distribution within the formation. Unfortunately, obtaining such data often necessitates costly retrieval methods and, in some cases, may not be feasible, particularly in regions where the well has been cased entirely.

In this paper, we present a comprehensive case study focused on a brownfield reservoir offshore Malaysia, which has started exhibiting sporadic sand production across several wells. The available core data are sparse, and the inherent heterogeneity of the formation renders core data potentially unrepresentative of the zones prone to sand production. To address this challenge, we propose an innovative methodology aimed at reducing uncertainty in grain-size distribution characterization.

Our approach begins with the utilization of available core data as a calibration tool for the nuclear magnetic resonance (NMR). To extract meaningful insights from the pair relation of core to NMR, we employ multiple machine-learning (ML) algorithms in cascade, depicted in Fig. 1. ML models are critical as they can analyze vast data sets generated by NMR to discern intricate patterns that may be beyond the scope of human interpretation.

First, the unsupervised model is factor analysis, which helps to unravel the intricate relationship between NMR data and core measurements. Subsequently, a deterministic model is employed to relate each NMR poro-factors to the corresponding core poro-factors to determine the grain size. In cases where NMR data are entirely absent, we employ a second ML model, class-based machine learning (CbML), to automate the clustering of data points. Lastly, within each resulting cluster, we employ a third ML model, artificial neural networks (ANNs), to discern the connection between standard triple-combo logs and the corresponding grain-size distributions from the offset NMR well.

The rigor of our methods is ensured through a blind validation process against an offset well with core data. This validation step guarantees the consistency and reliability of our grain-size distribution estimations, even in areas where no prior data were available. The same methodology has also been validated with another brownfield in offshore Malaysia to confirm the applicability of this study.

By implementing these innovative techniques and leveraging legacy NMR data, which otherwise will be left unused, we can significantly minimize uncertainty surrounding grain-size distribution, contributing to more precise and effective sand control deployment. This, in turn, enhances reservoir productivity and safety, offering a valuable solution to a common challenge faced in mature siliciclastic reservoirs.

Data-Driven Petrophysics: An Automated Approach to Parameter Optimization in Well-Log Interpretation
Kjetil Westeng, Aker BP ASA; Christian Lehre, Sopra Steria; Yann Van Crombrugge, Inmeta; Peder Aursand and Tanya Kontsedal, Aker BP ASA

In petrophysics, big data, comprising both core measurements and dynamic statistics, offers transformative potential for interpreting well logs using empirical evidence. This study investigates the practical applications of these data types, emphasizing their utility in automated interpretation systems.

The primary aim is to leverage data analytics to delineate the distribution of petrophysical properties through a comprehensive analysis of dynamic curve statistics and rock databases.

Building upon the foundational work of automated shale volume interpretation introduced in 2023 by Westeng et al., this study utilizes lithological knowledge to accurately map individual core measurements to their corresponding lithologies. Subsequently, core measurements, such as grain density, are categorized based on predefined multimeasurement criteria. Our rock and fluid database, detailed in Petersen et al. (2022), serves as the backbone for this endeavor. Concurrently, automatic trend curve analysis for various rock properties, including shale porosity, shale slowness, shale neutron response, shale resistivity, and vertical stress, are derived using the same shale volume interpretations. For other key properties, e.g., water resistivity, our framework incorporates insights from existing interpretations, enabled through a structured and rigorous organization of metadata.

We have formulated and implemented an automated framework that cohesively integrates core measurements with statistical curve analytics into petrophysical interpretation.

The innovative fusion of expansive core databases with automated log analytics can revolutionize petrophysical interpretation. This approach obviates the need for simplified methodologies and nonrealistic assumptions, enabling more precise, time-efficient interpretations. Importantly, it minimizes the role of subjectivity, promoting data-driven results. The methodology also clarifies when deviations from general data trends are justifiable, thus reducing the chance of interpretative errors.

Traditionally, utilizing extensive core data sets for optimal petrophysical parameter assignment has been labor-intensive and reliant on specialized knowledge. Our proposed framework offers a more efficient, high-quality alternative that challenges current industry standards. This disruptive approach enables the effective use of the abundant data available, thereby refining both parameter uncertainty and likelihood estimations. The authors anticipate that the Open Subsurface Data Universe (OSDU) will significantly improve the use of big data analytics of core data and well logs across the industry.

The figure depicts the concept of a fully automated formation evaluation workflow. On the left, a log plot contrasts automated predictions of grain density, porosity, saturation, and shale volume with actual core measurements. On the right, a flowchart details the integration of automatic parameter prediction from measured curves, the core/fluid database, and the extraction of contextualized learning into the automatic formation evaluation process.

Describing the Porosity of Presalt Carbonate Rocks Using Machine Learning
Gisella Roza Nunes, Jeferson Santos, Gilberto Raitz Junior, and Leonardo Borghi, Federal University of Rio de Janeiro

The porosity of presalt carbonate rocks is a petrophysical property used for characterizing the quality of oil and gas reservoirs. Integrating depositional characteristics, diagenetic modifications, and petrophysical properties challenges carbonate rocks' petrographic description and classification. This process demands time and expertise from geologists, as these properties are typically described through laboratory analyses involving the interpretation and integration of petrographic thin sections, drilling core samples, and well image logs. The present study has the objective to use machine-learning (ML) techniques for thin-section characterization, with an emphasis on porosity, quantifying the percentage of pores and the mineral of calcite, dolomite, and silica grains to correlate this data with wireline measurements from the well, such as elemental capture spectroscopy (ECS) and nuclear magnetic resonance (NMR). High-resolution scanning of 100 thin sections was performed, utilizing images captured under both plane and cross-polarized light conditions, referenced according to each sample's respective well and depth. Subsequently, these images were used to train a ML model based on the neural network for feature extraction (GPU) and the random forest classifier (CPU) for pixel classification. The segmentation of images for pixel classification is performed manually (supervised), where objects in the image are identified according to the interpreter (petrographer) who assigns pixels to specific classes (e.g., Pore Class 1, Calcite Class 2, Dolomite Class 3, Silica Class 4, and Unknown Class 5). These classes represent groups of objects consisting of individual pixels with similar characteristics. In other words, the interpreter identifies textures, colors, and shapes of the same class, and through repetition and training, a subset of data is assigned to each image. After training on the sample set, the random forest classifier algorithm classifies the trained data, resulting in a comprehensive map of the thin section. This information is presented as tables and calculated percentages based on the area. It is also possible to obtain a colored image that displays the characterization of the thin section based on the determined classes, which in the current approach are classified as (1) pores, (2) calcite, (3) dolomite, (4) silica, and (5) unknown. The petrographer performs the quality control of the analysis by comparing the trained thin section with the classified image. Consequently, the division of the elements in the thin sections was obtained, displaying the modal count of all constituents and the area of each analyzed pore. Visually, the accuracy of the results increased with the addition of trained thin sections, leading to improved pore delineation and reduced errors in mineralogical identification. Compared with manual descriptions of these same samples, the results obtained from ML are satisfactory, approaching the originally obtained modal counts. Furthermore, the algorithm is easily configuring complex measurement tasks, yielding quickly acquired results, capable of analyzing 10 thin sections in about 4 hours, especially when examined in JPEG format, providing additional insights into the studied well. These elements produced by ML can also be correlated with petrophysical profiles, aiding in the interpretation of porosity logs and even seismic data from the formation. Therefore, the study of using ML in thin-section descriptions is of great importance regarding accuracy and practicality, addressing a commonly performed task by geoscientists.

Enhanced AI-Driven Automatic Dip Picking in Horizontal Wells Through Deep Learning, Clustering, and Interpolation in Real Time

Alexandre Perrier, Alexis He, Nadège Bize-Forest, and Daniel Quesada, SLB

Borehole images in horizontal wells are challenging for dip picking. We observe mainly lengthy parallel and ovoid bedding dip traces called ''bull eyes,'' as the well may be subparallel to the bedding. This deviates considerably from the classic model of dip picking, which extracts only sinusoids.

So far, the delineation of non-sinusoidal bedding features has relied on a manual process that entails delineating multiple segments to define these features. Each segment has its dip value, and interpreters have traditionally relied on the average dip to estimate the true bed dip, which may not provide the most accurate results.

In this paper, we present a method that enables the precise automatic extraction of segments from non-sinusoidal features using an artificial intelligence (AI) model and propose an automated grouping mechanism for the segments. Such a solution is applicable in real-time scenarios—which implies working with partial data until the drill's final beat—facilitating geosteering guidance.

Our solution is an automated workflow that detects and picks non-sinusoidal bedding dip traces in real time in horizontal wells' borehole images and computes the corresponding orientation of the structure.

The workflow starts with borehole images and the associated segments provided by the “auto dip-picking” algorithm. A convolutional neural network detects bedding features and categorizes them as sinusoidal or non-sinusoidal bedding features. Subsequently, segments are regrouped within each bedding feature, creating comprehensive data sets for each feature. For sinusoidal bedding features, full ones are preserved, while fragmented ones in multiple segments undergo an advanced clustering mechanism based on orientation and derivate. Meanwhile, parallel and “bull eyes” structures undergo a transformative process; a recursive approach connects segments within the same layer. Then, we compute each layer’s global orientation.

The procedure ensures adaptability in real time. With the arrival of each new frame, we evaluate if the last detected structure extends into it. If so, a swift recomputation ensues, allowing our solution to provide results whose accuracy is improved dynamically with each new frame.

Our study yielded significant outcomes in automatically detecting non-sinusoidal bedding features and computing associated dips from borehole images in horizontal wells.

The integration of our advanced workflow reduced manual intervention. Previously taking 1 hour per kilometer of well to pick non-sinusoidal features manually, our solution combined with an auto dip-picking algorithm achieves the same task in a mere 12 minutes per kilometer. In addition, this workflow is versatile, catering not only to horizontal wells but also to vertical ones. We provide a solution capable of handling non-sinusoidal bedding and sinusoidal bedding features simultaneously with just one click. By embracing automation, we also eliminate subjective interpretations, ensuring a standardized and efficient analysis process.

This workflow has immediate implications for the oil and gas industry, as no other automated dip-picking solution exists on any platform for non-sinusoidal bedding features and promising efficiency gains and cost effectiveness.

Fault Reactivation in Presalt Carbonate Reservoirs Based on Geomechanical Modeling – Case Study: Sapinhoá Field

Maria Juliana Jauregui Suárez, Universidad Industrial de Santander; Daniel Mauricio Rojas Caro, Alessandro Batezelli, Emilson Pereira Leite, Gelvam André Hartmann, and Maria Liceth Cabrera, Universidade Estadual de Campinas

The reactivation of faults may affect the petrophysical properties (porosity and permeability) of rocks in the formations of interest. This scenario can compromise the integrity and efficiency of a petroleum system (from source formation until seal formation). Therefore, reservoir modeling plays a crucial role in the hydrocarbon industry by aiding decision making at different stages of reservoir development. Specifically, geomechanical modeling in reservoirs is essential to understanding the response of a rock environment to different changes in stresses, pressures, and strength. However, this process represents a significant challenge due to the heterogeneity of the elastic and petrophysical properties. These properties are influenced by different diagenetic processes, especially for the carbonate reservoirs of the Brazilian presalt. Nowadays, there are different rock typing tools that facilitate grouping rocks with similar characteristics. One of the most important is geomechanical facies (GMFs) that provide some clusters used to classify different sections or layers of rock based on their mechanical properties and their behavior under stress. The GMFs show a close relationship with total porosity (fundamental petrophysical property), as well as the elastic and strength properties of reservoirs. In this way, the objective of this work is the identification of rock facies with the most probable potential of reactivation of faults in the Barra Velha Formation corresponding to the study area, Sapinhoa Field, Santos Basin, Brazil. This process was divided into four main phases: (I) the development of a one-dimensional (1D) geomechanical model based on elasticity, rock strength, failure criteria, in-situ stresses, and pore pressure; (II) unsupervised classification into GMFs; (III) the definition of the orientation of in-situ stress fields, which was determined by interpreting non-catastrophic structural elements (breakouts (Bos) and drilling-induced tensile fractures (DFITs)); (IV) structural seismic interpretation (faults and horizons); (V) study of fault reactivation potential obtained by the stress polygon. To carry out this methodology, 10 wells were used with conventional and advanced geophysical well-log leakoff tests (LOT), formation pressure tests, and post-stacked seismic data. The results indicate an abnormally high fluid pore pressure (9.39 ppg) in the oil saturation zone and (9.38 ppg) in the water saturation zone concerning hydrostatic pressure (8.33 ppg). Also, we define one regimen fault classified as double normal-transcurrent based on minimum and maximum horizontal stress gradients and three main geomechanical facies: GMF1 – non-compacted and nondeformable rocks with low strength and high porosity; GMF2 – intermediate strength and porosity; GMF3 – compacted and deformable rocks with high strength and low porosity. Finally, based on the stress polygon, we obtained a fault reactivation scenario with an NE orientation generated by simulating a fluid injection (increased pore pressure) in a hydraulic fracturing or recovery process. The methodology applied in this work can be used for siliciclastic carbonate reservoirs.

Integrating Statistically Significant Laboratory Information in Variable T_2 Cutoff Logs for NMR Interpretation in Presalt

Bernardo Coutinho Camilo dos Santos, Willian Andrighetto Trevizan, Thais Fernandes de Mato, Edmir Ravazzi Franco Ramos, Leonardo Gonçalves, and Lucas Abreu Blanes de Oliveira, Petrobras

Among the different techniques used in well logging for formation evaluation, nuclear magnetic resonance (NMR) stands out as being able to probe the geometrical characteristics of porous media when the correct requirements are met. For instance, when dealing with a core sample saturated with a single fluid, there is a strong correlation between the relaxation times (T_1 or T_2) and the surface-to-volume ratio of the pore space. Moreover, if the porous medium is homogeneous, with a well-behaved relation between pore volume and pore-throat size, the T_1 or T_2 distributions are proportional to the pore-size distribution, which can be used to derive permeability models or to determine irreducible saturation through the application of relaxation time cutoffs. However, when analyzing complex carbonates such as the ones in presalt, one observes a wide variation in the cutoffs determined in the lab (ranging roughly from 50 to 700 ms), which can question the usefulness of such a petrophysical parameter for well-log saturation determination.

In this work, we tackle the problem of determining suitable T_2 cutoffs for well-log interpretation that are able to incorporate the variations seen in core samples, including uncertainties estimations that are compatible with both lab and log data. In our methodology, each T_2 distribution obtained in the lab (Fig. 1a) is used to emulate an NMR log response. This is done through the forward modeling of an NMR acquisition with the same parameters set in the well-logging tool, such as wait times and echo times, Fig. 1b. By contaminating the resulting echo trains with different realizations of random noise (compatible with the noise observed in the field data), and subsequent inversion to reobtain the T_2 distribution (Fig. 1c), this bootstrap procedure gives rise to a population of T_2 distributions and corresponding cutoffs that are more likely to appear in a real well-logging operation. By analyzing the similarity between an NMR well-log distribution and the ones generated from the lab data, we obtain, for each depth, a histogram of probable T_2 cutoffs (Fig. 1d). The similarity metric was chosen based on its capability of clustering the laboratory samples in a way compatible to a rock typing method based on petrography and flow zone indices.

We applied this methodology to obtain variable T_2 cutoff curves, which include most probable, P10, P90, and other statistics, for different presalt well logs. The resulting saturation curves showed an excellent agreement with Dean-Stark measurements for oil and water saturations performed in core logs (Fig. 1d). The uncertainties in saturation obtained in the well log were able to explain the variations in the Dean-Stark measurements. As the methodology is based on the available NMR lab data, it can be continuously refined as more core measurements are performed.

Novel Machine-Learning-Driven Framework for Rock Typing and Permeability Prediction Using Borehole and Spatial Data – A Case Study From a Supergiant Carbonate Reservoir in Abu Dhabi

Gennady Makarychev, Alaa Maarouf, Lulwa Almarzooqi, Luisa Ana Barillas Cortez, Midhun Madhavan, and Hussein Mustapha, SLB; Nader Gerges and Chakib Kada Kloucha, ADNOC

Rock typing and permeability prediction are among the most challenging tasks in petrophysical synthesis workflows. Commercial petrophysical evaluation platforms offer separate tools for supervised or unsupervised classification (i.e., rock typing) and prediction. In practice, petrophysicists must run them sequentially, often repeating tasks several times to achieve satisfactory results. Another deficiency of the available products is their lack of integration of the spatial data. Borehole data are treated equally, without consideration of a sample's position in 3D space and possible vertical and lateral heterogeneity. The last ones are usually an object of the study in the later stage of 3D model construction.

In this work, we present a novel framework to intelligently solve simultaneously classification and regression tasks by leveraging the latest advancements in machine learning. We also show the importance of integrating the sample's position in 3D space for more accurate rock typing and permeability prediction.

The workflow is split into two parts to create rock types with core data and propagate them into the log domain.

In the core domain, several interactive tools are developed to provide comparison between candidate rock types outcoming from core and thin-section descriptions, and quantitative classification from capillary pressure curves. A synthesis between them ensures both geological and petrophysical meanings of created rock types. At the next step, rock types can be propagated to conventional analysis (porosity – permeability – lithology) core samples using semi-supervised classification.

In the log domain, we start with a first proxy of permeability prediction using a distance-weighted KNN approach. The predicted permeability feeds into a semi-supervised classification model to create the first proxy of rock-types distribution using logs.

Finally, we organize a loop of regression and classification where we predict permeability and rock types. The proposed novel framework integrates classification and regression tasks in a single workflow.

In this work, we developed and tested the workflow on real data from a large mature oil field in Abu Dhabi. We managed to effectively propagate rock types from tens of capillary pressure curves to thousands of conventional core analyses and, furthermore, to more than 600 vertical and horizontal wells with more than 2 million depth samples.

The proposed novel approach shows superior results compared to existing methodologies when validated with the core data.

Regression – Classification loop is allowed to minimize permeability prediction and rock typing error. Validation with blind test wells showed that for more than 80% of samples, the match with core permeability is within an uncertainty range of the predicted value. High-permeability streaks and baffles effectively propagated to noncored wells.

The integration of geospatial information allows the selection and weighting of the training samples for classification and regression not only by the similarity of the borehole data with the predicted sample but also by the similarity of their position in the reservoir. Such an approach allows the preservation of local heterogeneities and global trends for predicted permeability and rock types.

The workflow allows users to complete time-consuming tasks that require a sequential approach consisting of several repeated runs using available commercial platforms in a single run. A user-friendly interface and developed interactive tools help to fine-tune inputs and parameter selection to achieve the best results.

The Impacts of Bed Boundaries, Bed Thickness, and Sensor Measurement Resolution on Machine-Learning Facies Prediction

Andrew McDonald, Geoactive Limited; Edward Downer, Axis Well Technology; Ryan Banas, PetroRes Consulting; Tegwyn Perkins, Geoactive Limited

Over the past decade, the interest and applications of data-driven machine-learning workflows within the petrophysics domain have increased significantly. Despite this increased adoption, there are still numerous challenges and difficulties in adapting machine-learning algorithms to petrophysical data sets. Two of these challenges are dealing with varying measurement resolutions between different logging tools and the impacts on measurement response encountered at bed boundaries. Well-log measurements are diverse, multiscale, highly multidimensional, and have varying depths of investigation. Not accounting for these aspects of logging measurements when building models can increase model uncertainty, reduce model performance, and introduce data alignment issues.

Within this study, we investigate the issues of multiresolution well-logging measurements using a mixture of simulated data and real-world data for the process of facies prediction. Several techniques are discussed, including data resampling to the lowest and the highest resolutions within a simulated data set, feature generation, and inversion. Using a series of synthetic earth models with varying complexity, we explore the impacts of varying measurement resolutions. First, we train and predict facies using the earth model data and a neural network. Secondly, we use the earth-model-trained neural network model to predict facies based on measurements at a log resolution scale. Thirdly, we train a neural network on well-log resolution data and predict facies with the model using the same resolution data.

Additionally, to assess the impact on real-world data, we explore the impacts on facies prediction within thinly bedded geological sequences where bed thickness is below the resolution of the logging sensors.

Based on facies prediction from multiple earth methods, it is demonstrated that even in very simple earth models, facies are erroneously predicted at bed boundaries. These errors intensify when model complexity and uncertainty increase. When real-world logging data from thinly bedded reservoirs is used for facies prediction, increased uncertainty and misprediction of facies increase as the bed thickness decreases.

By exploring the challenges and impacts of multiresolution data on petrophysical machine-learning models, this paper aims to provide a clearer understanding of the necessary steps in preparing data prior to applying these techniques. Additionally, through multiple earth model simulations and case studies with real-world logging data, this paper will help identify how the error predicting facies from both imperfect continuous log data and imperfect core data manifests itself when the formations become less homogeneous.

SPORSE: DIGITAL ROCK PHYSICS FOR FORMATION EVALUATION: ARE WE THERE YET?

Empirical Determination of the Effective Solid Modulus in Organic-Rich Shales

K. Larkin Spires, Lori Hathon, and Michael T. Myers, University of Houston; David Myers, MetaRock Laboratories; John Castagna, University of Houston

Fluid substitution using Gassmann’s equations is a frequently used procedure in the petroleum industry for applications such as direct hydrocarbon detection, carbon sequestration monitoring, source rock evaluation, and elastic moduli and brittleness estimation in unconventional shale reservoirs. Thomsen showed a logical flaw in Gassmann’s derivation that is bypassed in Brown and Korringa. However, Brown and Korringa’s fluid substitution is difficult to implement even when using samples in a lab. This research is an experimental validation of a semi-empirical approach by locally calibrating the rock properties necessary for use in the Brown and Korringa fluid substitution model.

The first phase consisted of calibrating a rock physics model to approximate the unknown dry frame and porosity bulk moduli with real-world data. This was done using well data from seven hydrocarbon-rich

shale formations. This well data included fluid information, a petrophysical analysis with mineral and kerogen volumes, sonic, and density information. Three parameters were used to locally calibrate the missing moduli. After calibrating, a forward model estimated the brine-saturated bulk modulus. To validate our model, lab measurements were performed on synthetic samples. By using a 3D-printed plug consisting of thermoplastic polyurethane (a soft, flexible plastic typically called TPU) and polylactic acid (a rigid plastic typically called PLA), we are able to avoid hysteresis and complete fluid substitution on samples with known porosity, composition, and pore geometry. A triaxial cell system is used to measure strain as a function of changes in effective stress, deviatoric stress, and pore pressure. The static measurements produce Young's modulus and Poisson's ratio. The fluids used to generate pore pressure include He, N_2, CO_2, and Ar. The bulk modulus, dry frame modulus, mineral modulus, and Skempton's coefficient will be derived from the static measurements. These moduli will be used to perform forward modeling from a base case of He-saturated state to saturation with the other fluids using Gassmann's, Berryman-Milton's bimineralic formulation of Brown and Korringa, and the previously developed semi-empirical approach. This methodology allows for the comparative analysis of models with experimental data.

In using the semi-empirical model, we found that using the Reuss average in place of the Hill average in the mineral modulus produced better results. Furthermore, in performing fluid substitution to brine with the two methods, Gassmann's formulation using the Hill average produced nonphysical values for the dry frame modulus in contrast to the semi-empirical method that produced reasonable values for all data points. The experimental static measurement data provide validation for the use of the semi-empirical Brown and Korringa fluid substitution model relative to Gasssman's substitution model for forward modeling of well-log data and 4D time-lapse monitoring of fluid injection and depletion sites.

Evaluation of Genetic and Geometric Features Extracted Using Automatic Segmentation for the Characterization of Porosity and Permeability of Reservoir Facies From Tartaruga Verde Field, South of Campos Basin

Matheus Augusto Alves Cuglieri, Paulo Henrique de Oliveira, Marcelo Ramalho Albuquerque, and Leonardo Alencar de Oliveira, Petrobras

Carbonate rocks are responsible for a considerable amount of hydrocarbon reservoirs worldwide. In Brazil, a huge part of petroleum reserves is associated with carbonatic facies formed during the Aptian and Albian times, especially on offshore basins of the east coast. These sedimentary textures have great complexity due to many possibilities of pore allocation, resulting from the interrelation of different geological processes (depositional and diagenetic) on specific timings and intensities. Beyond quantification, the whole characterization of the porosity on carbonates needs geometrical pore structure data for a better understanding of how fluids could be stored and how efficiently they could flow.

The Tartaruga Verde Field, located in the southern part of Campo Basin, 127 km far from Macaé/RJ, is an important player in this basin, producing hydrocarbonates since 2018.

The reservoir is composed of carbonate sediments formed under high to moderate energy conditions during Albian times, represented by reworked facies forming metric to decametric shoals. Facies formed under low energy conditions, like packstones and wackestones, are interpreted as the distal parts of these shoals or the sedimentary record of paleo-lows generated by tectonic movements. Diagenesis is also important, mainly as dolomitization and karstification are identified on different scales.

The methodology presented here focuses on the characterization of the solid matrix and porosity in terms of mineralogical composition and geometrical features, aiming at the impact of these on properties like acoustic impedance, porosity, seismic velocity, and their relations. Using automatic segmentation deep-learning algorithms trained on a large data set of AxioScan and QEMScan acquisitions of carbonate samples, several geometric features of the pore geometry of the reservoir facies of the Tartaruga Verde field were extracted and analyzed. The main goal of this study is to evaluate how the geometric features of porous systems can influence reservoir properties. Different data are used from multiple scales and origins.

As a result, the characterization of a porous system and solid matrix and their relationship with the genetic pathways of the facies identified could provide better geological models and production previsibility. This methodology has the potential to be widely applied under different geological contexts, due to data availability and efficient tools to provide and analyze these formations.

Fast and Automatic Extraction of Fracture Apparent Attitude Based on CT Images of Full-Diameter Cores

Ying Zhou and Xin Nie, Yangtze University

Fractures play a critical role in reservoirs as fluid conduits and storage spaces. The distribution and characteristics of fractures are relevant to the presence of high-yield reservoirs. To accurately analyze and observe fracture parameters, three-dimensional (3D) digital cores generated from computed tomography (CT) are employed. However, the commonly used method to extract fracture parameters is the moment of inertia (MIN) method, which is greatly affected by the artifacts and noises and requires a lot of computing power to calculate the entire 3D digital core. The method also requires a skilled researcher to perform each step, which is time consuming and laborious manually. Therefore, new methods are needed to improve the efficiency of fracture apparent attitude extraction.

In this study, a fast and automatic system for extracting the apparent attitude of fractures in CT images of full-diameter cores is proposed, which integrates the least-squares method, singular value decomposition method, and principal component analysis method. The workflow consists of the following steps. First, two orthogonal cross sections are obtained from the 3D digital core and converted into binary images. Then, the minimum external rectangle is extracted by the connectivity domain analysis, and the coordinates of the four fracture feature points in the core image are automatically extracted; the user can choose a more suitable method to fit the fracture plane. Finally, the apparent dip angle and direction of the fracture are calculated by calculating the normal vector of the plane. In this paper, six sets of samples with a total of 24 fractures were selected. The three methods have little difference in the results of extracting fracture parameters, among which the least-squares method is more effective.

The results of the MIN method and the least-squares method show that in all samples, the errors of the apparent dip angle of the fractures are within 3°, and the maximum value of the absolute error is 2.15°. The average absolute and relative errors are 0.69 and 17.79%, respectively. Throughout all the experimental data, when the fracture dip angle is less than 5°, the calculation error of the direction will be larger. This is because when the dip angle is small, the fracture is almost horizontal, and a small change in the dip angle will result in a large change in direction. In addition, the fitting of fractures using the least-squares method is basically better than 0.9 for high-angle fractures. Some low-angle fractures are fitted with a lower degree of goodness, which is mainly due to the irregularity of the fracture surface, resulting in a large deviation of the coordinates of the characteristic points from the plane of the fractures. Still, since the fractures are close to horizontal and the error of the extracted apparent dip angle of the fractures is not large, it doesn’t affect the geological evaluation. In conclusion, the system proposed in this paper can quickly, automatically, and accurately extract the apparent dip angle and apparent direction of fractures. The application of this system to fracture attitude extraction in full-diameter core images can significantly improve efficiency. However, since the full-diameter core lacks the real position and orientation information, the dip angle and direction we obtain are only the apparent attitude and cannot reflect the original attitude of the fractures. Therefore, it is necessary to combine the core data with the microresistivity imaging logging data and other wellbore wall imaging tools to calibrate the true fracture attitude to achieve a more accurate fracture characterization in the well.

Influence of Salt Concentration and Type on Dielectric Permittivity of Rocks

Zullkuf Azizoglu and Zoya Heidari, The University of Texas at Austin

Ionic properties and concentration significantly influence the response of brine-saturated rock samples to electromagnetic disturbance. However, the dielectric permittivity response of rock samples under different ionic conditions is poorly described. This significantly limits the potential information that could be gained from dielectric permittivity measurements about the pore geometry and fluid content. Therefore, the influence of salt concentration and type on broadband dielectric permittivity must be quantified in the pore- and core-scale domains to develop analytical dielectric permittivity models. The objectives of this paper are to (a) investigate the influence of salt type and concentration on dielectric permittivity via experimental measurements and pore-scale simulations and (b) identify the limitations of current effective medium theories in the interpretation of dielectric permittivity measurements in samples with different ionic conditions.

We investigate the influence of salt concentration and type on the dielectric permittivity of pore- and core-scale Berea sandstone samples. First, we perform frequency-domain dielectric permittivity simulations to quantify the response of the pore-scale models to electric field excitation. The frequency-domain dielectric permittivity simulator solves Maxwell's equations under quasi-static conditions at discrete frequencies. We simulate the dielectric permittivity in the frequency range of 20 MHz to 3 GHz. We run the simulations in samples saturated with NaCl, KCl, and $MgCl_2$ brines. The salt concentration of the brine solutions ranges between 2 to 100 PPT. For the core-scale analysis, we fully saturate the samples with different brine solutions at varying salt concentrations. In the core-scale domain, we use the exact brine solutions and salt concentrations defined for the pore-scale analysis. The dielectric permittivity measurements were conducted using a network analyzer with a high-temperature coaxial probe setup in the frequency range of 200 MHz to 3 GHz.

We observed that relative permittivity at 1 GHz decreases with increasing salt concentration, irrespective of the brine type. However, the type of salt significantly controls the magnitude of the decrease in relative permittivity. After increasing the salt concentration from 10,000 to 100,000 PPM, relative permittivity at 1 GHz decreased by 7% and 11% when the samples were saturated with KCl and NaCl brine solutions, respectively. Furthermore, this behavior was enhanced as the frequency decreased. The impact of salt type on relative permittivity was negligible in samples saturated with 10,000 PPM brine solutions. Finally, we examined the potential errors that could arise from assuming an inaccurate salt type in the interpretation of dielectric permittivity measurements. We observed that incorrect assumptions about the brine type could result in up to 20% relative errors in water saturation assessment via dielectric permittivity measurements. Therefore, taking the influence of salt concentration and type into account is critical for a reliable interpretation of dielectric permittivity. The outcomes of this work will be helpful in the interpretation of dielectric permittivity measurements in formations with variable salt concentrations of formation water. Additionally, in the cases where the salinity of the formation water is unreliable, this work will illuminate the extent to which the dielectric permittivity measurements can be used for petrophysical analysis.

Insights of Core Analysis Data Interpretation by Use of Digital Rock Physics
Mohammed Fadhel Al-Hamad and Denis Klemin, SLB; Shouxiang (Mark) Ma, Saudi Aramco; Wael Abdallah, SLB

Modern digital rock physics (DRP) has been around for two decades and is continuously improving with developments of high-resolution imaging, faster computing, and an improved understanding of rock petrophysics. Traditional applications of DRP have been predicting rock properties that are difficult to measure in challenging conditions, such as tight rocks or irregular-shaped rock samples. In this study, DRP is used to help better understand physical measurements and their interpretations and reconcile different core analysis data for a more complete formation evaluation.

Carbonate core samples were mounted in a specially designed CT scannable core-holder that stress can be applied to simulate reservoir conditions. High-resolution micro-CT was used to scan the samples at different stresses to observe the effect of stress on the pore structure. Based on the high-resolution images, DRP was used to extract rock properties at stress, such as capillary pressure. The effect of stress on rock properties could be studied systematically. To complement and calibrate rock properties derived from DRP, physical measurements were also conducted, including X-ray diffraction (XRD), thin section, porosity and permeability, and centrifuge and porous plate Pc at stresses.

Results from this study of integrated DRP and physical measurements show that Pc obtained by different methods agrees well at ambient conditions. With increasing applied stresses, differences in Pc derived from different methods have been observed and are explainable by detailed studies of the effect of stress on pore structures, as observed from DRP. In addition, taking advantage of DRP's flexibility and capability to conduct systematic studies, correlations between applied stress and differences in changes in rock properties can be obtained, which can then be used in practical integrated reservoir studies.

Using DRP helps to explain physical measurements and interpret results to gain insights into complex relationships between rock properties and test conditions of core analysis to ensure applications of rock properties are fit for purpose.

Mapping Mineralogy to 3D Digital Rock Using Multimodal Multidimensional Image Registration
Mohamed Sarhan, Lori A. Hathon, and Michael T. Myers, University of Houston; Alon Arad, Automated Analytics

The development of large-scale underground energy storage technologies is necessary to integrate renewable energy into the global energy market. Siliciclastic reservoirs generally represent promising geological storage sites. However, some risks might be associated with storage in these reservoirs, such as mineralogic alteration and/or geomechanical failure due to the cyclical nature of injection/depletion associated with hydrogen or methane storage. Therefore, it is critical to understand the influence of mineralogy and texture on grain-scale deformation mechanisms that arise during cyclic injection/depletion. Utilizing digital rock imaging and image analysis techniques along with geomechanical measurements performed on the same rock volume provides a powerful approach to investigate the impact of microstructure on the geomechanical response of the sample of interest. Although CT scanning technology allows the characterization of three-dimensional (3D) geometry and pore space connectivity, the generated X-ray attenuations are not sufficient to distinguish mineralogy or to capture pore/matrix features below the image resolution. Accordingly, the aim of this paper is to couple the information from two-dimensional (2D) and 3D imaging modalities using a newly developed tool for multimodal/multidimensional image registration to obtain a multimineral 3D digital rock for investigating the impact of framework mineralogy and cement volume on the geomechanical response of sandstones to multiple injection/depletion cycles.

The paper investigates two sandstones that are dramatically different mineralogically. The first sample is the Boise Sandstone, which is classified as an arkose, while the second sample, the Castlegate Sandstone, is classified as a sublitharenite. In order to link mechanical response to microstructural attributes of a given sample, a multiscale workflow is used. First, the sample was imaged using micro-CT at resolutions of 13 µm/pixel. To capture mineralogy and pore/matrix features below the image resolution of micro-CT, a thin section was cut and scanned using optical microscopy. A cyclic uniaxial-strain test was performed on the sample to simulate energy storage. The post-test sample was imaged again using micro-CT and optical microscopy. Using a newly developed image registration tool, each thin section is registered to its corresponding CT volume to develop a multimineral 3D digital rock. Analyzing the pre- and post-test images documents the physical response to multiple cycles of injection and depletion. The workflow is illustrated in Fig. 1 (upper row). Registering images is an optimization problem in which the cost function quantifies the quality of the alignment between two images with respect to several transform parameters. Most commercially available software packages rely on mutual information that lacks spatial information for multimodal image registration. This leads to difficulty in registering 2D to 3D images. This study, in contrast, employs a proper mathematical optimization process to minimize spatial errors to acceptable limits by combining spatial information through gradient information with mutual information. The 2D/3D image registration workflow is summarized in Fig. 1 (lower row).

By comparing pre- and post-test images of the Boise Sandstone, we observe the presence of grain fractures predominately developed in K-feldspar grains and compaction of intergranular pores. The grain size is reduced from 260 to 215 µm, and intergranular porosity has experienced a net compaction of 4%. This suggests the inadequacy of highly feldspathic, coarse-grained sands for seasonal hydrogen or methane storage because of the strain-weakening response to stress cycling.

Combining multiscale multidimensional imaging techniques provides a powerful tool for a better understanding of the physical response to multiple cycles of injection and depletion on reservoir quality and, thereby, storage efficiency.

Predicting Rock Compressibility Based on the Statistical Data From Micro-CT and Thin Sections
Ghaleb Al-Gobi, Michael T. Myers, and Lori Hathon, University of Houston

Rock structure is often expressed in terms of grain sorting, mineralogy, and inclusions, which often obey fractal statistics. This comes with many benefits, including reducing the computations required to model the force chains connecting the fabric grains. This data may be obtained from either thin sections and/or micro-CT scans. Thin sections, while they provide high-resolution images of both the grains and their edges, offer biased estimates of the contact areas and contact lengths. Micro-CT helps with this by extending the imaging to 3D but at a significantly lower resolution. This paper utilizes data from both micro-CT and thin sections to take advantage of both strengths to build a network model for predicting the rock's compressibility. This model incorporated deviations from a self-similar scaling of network statistics to predict the stress-dependent uniaxial compaction coefficient.

The micro-CT scanner is used to scan a 2-in. by 1-in. diameter sample sand pack comprised of 70% quartz (Q) and 30% feldspar (K-spar) before applying uniaxial stress to the sample. Three increasing cycles of stress are applied until a stress of 2,250 psi is reached. Between each cycle, the sample is allowed to stabilize for 1 hour before unloading. The sample is then scanned in the micro-CT to obtain the force chains. The process, therefore, includes four micro-CT scans to monitor the three stress cycles. This experiment is repeated using samples with 95% quartz and 5% feldspar as well as 85% quartz and 15% feldspar. The data from micro-CT are processed by removing filtering noise and determining the edges of the grains in each slice. To achieve this, customized techniques for scaling the slices' intensity within the sample's stack, denoising the slices, and determining the edges were built to increase the resolution of the slices and find the close and far edges of the grains. The shape and intensity of the grains from the thin sections and micro-CT are used to determine the individual grain mineralogy.

In addition to the image processing techniques used with the micro-CT data, a customized physics engine is built to simulate the experiment digitally. The processed data from the micro-CT is fed to the physics engine to create a 3D model of the rock and use machine learning to study the geometry of the grains. This allows the engine to generate realistic grains to run virtual simulations to simulate the stress-dependent tests. The engine calculates the forces propagating through the contact areas between the grains. This creates a network of force chains that can be visualized. The statistics of the force chains and the evolution of these networks are studied as a function of the weight percentage of the inclusions is increased.

The experiments exhibited a significant stress dependence for the rock compressibility. The increase in the K-spar ratio led to an increased compressibility of the sample, with the peak compressibility occurring at decreasing stress. As the fraction of the inclusions increases, the probability of a force chain encountering the inclusion increases, causing these effects. The network of the force chains initially obeys fractal statistics, allowing for more efficient computations in the model. This model may also be used to calculate the effects of grain size, differing inclusions, and the impact of stress history.

Synchrotron Source Zoom-Tomography of Porous Media at the MOGNO Beamline
Nathaly Lopes Archilha, Daphne Silva Pino, Talita Rosas Ferreira, Victor Ramon Martinez Zelaya, Everton Lucas de Oliveira, Aluizio Jose Salvador, Bruno Becker Kerber, Murilo de Carvalho, Gabriel Schubert

Ruiz Costa, Paola Cunha Ferraz, Larissa Macul Moreno, Otávio Moreira Paiano, João F.G. de Albuquerque Oliveira, and Eduardo Xavier Miqueles, Brazilian Synchrotron Light Laboratory; Rodrigo Surmas, Petrobras; Harry Westfhal, Jr., Brazilian Synchrotron Light Laboratory

Greater spatial and temporal resolution are the main advantages of X-ray computed tomography of synchrotron light sources over benchtop scanners. This difference is due to the smaller size of the X-ray source and the higher photon flux achieved in particle accelerators.

The Brazilian fourth-generation synchrotron light source, Sirius, will count on a world-leading micro and nano X-ray imaging beamline, MOGNO, which will focus on time-resolved and multiscale experiments. This work aims to present the status of MOGNO and recent imaging of diverse examples of porous media (focused on rocks) using its cutting-edge zoom-tomography capability, which enables continuous magnification of the image.

The cone beam geometry of MOGNO allows for performing zoom-tomography. It covers up to 27 m between the sample and detector. The beamline will be equipped with a direct area detector that will provide a maximum field of view (FOV) of ~85 × 85 mm^2. At this maximum FOV, the sample is positioned close to the detector, and the image resolution is 55 µm, which is limited by the pixel size of the detector. By moving the sample away from the detector and towards the X-ray source, regions of interest within the sample may be selected with smaller FOVs (down to ~150 µm) and with higher image resolutions (up to 120 nm), which is limited by the projected size of the X-ray beam focus. Nevertheless, the maximum FOV for a given experiment must respect the X-ray transmission dependency on the chemical composition of the sample. In this regard, MOGNO works in high (22, 39, and 67.5 keV) X-ray energies, yielding a versatile beamline that can be used to image several materials, ranging across rocks, soils, plants, fossils, and biological tissues, among others.

Particular attention is given to the study of the microporosity of reservoir presalt rocks at multiple scales using zoom microtomography. Tests were performed with presalt rock plugs of 3 mm diameter. As MOGNO is intended to be a fast-scan beamline, different algorithms for image reconstruction and segmentation are currently being studied to establish a work pipeline at the beamline that will favor the decision-making process for choosing regions of interest for zoom, which will later be used for porous rocks and other porous materials. We expect to be able to correlate micropores and pores throughout the different scales and, by future analysis of other presalt reservoir rocks with zoom microtomography, to shed light into petrophysical models for more efficient oil exploitation.

ENERGY TRANSITION – REDUCING SUBSURFACE RISK IN MODELING AND MONITORING

Creep-Cyclic Stress Tests in Salts for Underground Storage

Talha Hassan Khan, Michael T. Myers, Lori A. Hathon, and Gabriel C. Unomah, University of Houston

Salt is an elastoviscoplastic material with low permeability and exhibits time-dependent deformation. These properties are beneficial for predicting the stability of salt caverns as a storage medium for CO_2 and H_2 storage projects. The brittle deformation associated with cyclical loading could result in pore collapse, and the ductile deformation from creep could lead to cavern closure. It is necessary to predict the geomechanical changes during creep-cyclical stress tests in salts. In this study, we conducted combined creep and cyclic tests on salts. The resultant visual microstructural damage was also investigated.

The combined creep-cyclic tests were conducted on servo-controlled triaxial testing apparatus in the University of Houston laboratories. The samples were subjected to confining stress, short holding time, cyclic loading-unloading, and increased to a new confining stress regime. This procedure is repeated for multiple loading-unloading cycles and maximum axial loading at a constant axial strain rate. The pre- and post-test thin sections and microcomputed tomography (CT) scan data are obtained to visualize the degree of microstructural damage.

The fountain plots (axial stress vs. axial, lateral, and volumetric strain) show the degree of stress hysteresis as a function of the opening and closing of microcracks. The initial isostatic loading of confining stress results in microcrack closure. The following hold time (creep) results in strain hardening transitioning to a steady-state ductile deformation characterized by the modified Cam Clay model and stress-strain profiles. This stress path will show the evolution of the yield surface towards strain hardening and increasing irrecoverable strains at each confining stress stage. The thin sections and micro-CT scans show signs of compaction strains, grain boundary microcracks, and increased crystal dislocation densities (formation or reorganization of subgrains) due to accumulated microstructural damage or irrecoverable strains from both creep and stress cycling.

The experiment provides a means of predicting the long-term geomechanical response and damage characteristics associated with rock salts under multiple stress cycles for CO_2 or H_2 storage projects to ensure the stability and serviceability of underground salt caverns.

Dynamic Reservoir Rock Typing and CO_2 Flow Characteristics on Supercritical CO_2-Brine System in Reservoir Rocks

Muhammad Nur Ali Akbar and Rolf Myhr, Prores AS

Dynamic reservoir rock typing plays a pivotal yet relatively unexplored role in the field of CO_2 storage, serving as a critical component in the assessment of CO_2 flow characteristics within aquifer reservoirs undergoing dynamic reservoir modeling. This study exhibits an approach to establishing dynamic reservoir rock types for the supercritical CO_2-brine system by leveraging special core analysis (SCAL) relative permeability data.

Our research builds upon an extensive data set of 22 sandstone and 13 carbonate core plugs collected from potential CO_2 storage aquifers in Alberta, Canada. The data set includes measurements of relative permeabilities acquired during both primary drainage and primary imbibition cycles. The rock typing methodology employed in this study integrates pore geometry and pore structure (PGS) with the true effective mobility (TEM-function) approach, offering a comprehensive characterization of multiphase fluid flow properties within these rocks. Subsequently, we present the outcomes of the dynamic rock typing process through both one-dimensional (1D) and three-dimensional (3D) representations, accompanied by the simulation of flow characteristics using 3D numerical modeling.

Our findings reveal the establishment of four distinct rock groups based on the relationship between pore geometry and the pore structure variable in our samples. Of paramount importance, our results clearly demonstrate discernible groupings of TEM-function curves based on the relative permeabilities of brine and CO_2, as observed in both primary drainage and imbibition experiments. Furthermore, we derive averaged relative permeability curves from the TEM-function and transform them into conventional relative permeability values for each rock type. Notably, our 3D numerical simulations of flow dynamics uncover unique and contrasting multiphase fluid behavior within each rock group, particularly evident in the evolving saturation profiles over time.

As a novelty, the integration of PGS rock typing and TEM-function analysis proves to be an effective and efficient method for grouping capillary pressure and relative permeability data in the context of supercritical CO_2-brine systems, ensuring consistency while minimizing overlap within each rock type for sandstone and carbonate reservoir rocks. This approach offers an alternative solution for the rapid averaging of relative permeability data within distinct rock types, speeding up dynamic reservoir modeling. The insights gained from this research have the potential to revolutionize our understanding of fluid flow behavior within aquifer reservoirs, ultimately advancing the field of CO_2 storage and dynamic reservoir modeling.

Importance of Well Integrity Measurements Throughout the CCS Project Life Cycle

Dirk Valstar, Robert Laronga, Andrew Dodds, Alec Nettleton, and Casey Chadwick, SLB

In the carbon capture and sequestration (CCS) operating environment, assurance of well integrity becomes both more important and more technically challenging than in typical oil and gas operations. Its importance is amplified by government regulators who are well aware of the risks and consequences associated with an eventual loss of containment of stored CO_2 and insist on a high level of scrutiny. For the operator, a catastrophic loss of containment could spell a premature end to the operating phase of the project at a huge financial loss. Meanwhile, the technical challenge of assuring well integrity is amplified by the corrosive, buoyant, and highly mobile nature of CO_2 in the subsurface and by the long service lifetime (100 years+) required by these projects. Ironically, the measurement of well integrity may be complicated by the exotic well construction materials selected to address these very challenges.

Nonetheless, measurements of well integrity play a critical role and will continue to do so throughout the lifetime of CCS projects in at least four ways:

1. Identifying and assessing the condition of legacy wells within the area of review (AOR)
2. Verifying and validating the placement of CO_2-resistant cement (or other material) and/or the condition of CO_2-resistant casing strings upon construction of new wells
3. Proactive continuous or periodic time-lapse monitoring of the casing, annulus, and near-wellbore region
4. Diagnostic measurements to pinpoint suspected eventual deficiencies, characterize them, and develop remediation plans

We review a broad range of well integrity measurements, including acoustic and ultrasonic logs, electromagnetic logs, mechanical caliper logs, pulsed-neutron logs, distributed measurements of temperature and acoustic vibration made via either permanently installed or temporarily deployed fiber optic, oxygen activation logs, production logs, and the old-fashioned mechanical integrity test. We discuss the applicability of each class of measurement to the various phases of CCS projects, illustrated by North American examples.

We examine the impact of special materials such as CO_2-inert cement or epoxy resins on both the measurement and the interpretation of well integrity. We also consider the impact of corrosion-resistant alloys on the casing integrity monitoring strategy. The end result is a recommended well-construction and monitoring strategy for CCS projects, balancing considerations of operational practicality, regulatory requirements, and the true risks faced by the project to assure safe and continuous operation and containment for the next century.

Incorporating Emissions Into Wireline Formation Evaluation Risk Assessments
Lee Hyson, Hamish Munro, Ron Ford, and Guy Wheater, Gaia Earth Group

As the global industry undergoes a transformative shift towards sustainability and emission reduction, traditional risk assessment metrics no longer capture the full spectrum of potential consequences. Beyond the conventional factors of injury severity, cost, traditional environmental definitions, and downtime, carbon impact would seem to be a requisite dimension. This necessitates the incorporation of emissions into operational risk assessments for a more comprehensive understanding of the implications.

A conventional wireline formation evaluation sticking risk assessment has been modified by integrating emissions considerations into our analysis. The methodology involves the development of a specialized calculator that factors in variables like well depth, rig type, wireline descents, and mobilization distance to quantify emissions across a range of operational scenarios. The scenarios encompass severe outcomes like loss of a wellbore, moderate incidents like wireline fishing operations, lighter severity situations requiring pipe-conveyed logging or tripping to replace a failed tool string, and fully mitigated scenarios with successful wireline operations completed.

With the introduction of emissions as a critical risk metric, the imperative for thorough de-risking during the assessment and planning stages becomes more significant than ever. The results of our exercise put into clear focus the impact that operational risks and NPT scenarios can pose on emissions targets. For example, if a drillship on a 27,000-ft deepwater well with 6,000 ft of open hole were to lose the borehole due to unfishable tools, the emissions impact would be 3,500 metric tons of CO_2e equivalent to you driving an average car 15.7 million miles. Successful fishing operations, a much more favorable outcome, would still result in at least 466 metric tons CO_2e. More commonplace tool failures at TD or an operational plan to log on drillpipe can result in over 400 metric tons CO_2e. In contrast, a fully mitigated wireline run provides a relatively smaller 122 metric tons of CO_2e. The implication of emissions consequences elevates the urgency of proactive de-risking to deliver the industry's pursuit of sustainable and responsible practices. The findings from this study can help operators to better evaluate wireline formation evaluation risks, as well as help other service providers apply the methodology to their operational disciplines.

Quantifying the Impacts of Reservoir Geochemistry and Pore Structure on the CO_2 Diffusion and Leakage in Organic-Rich Mudrock Formations and Caprocks

Ibrahim Gomaa, Zoya Heidari, and D. Nicolas Espinoza, The University of Texas at Austin

Depleted gas reservoirs often have complex geometries with varying porosity and permeability distributions. Quantifying CO_2 diffusion in such heterogeneous reservoirs remains challenging, especially when considering the interactions between CO_2 and different rock types and pore structures. To ensure the long-term effectiveness and safety of CO_2 storage, it is essential to understand and quantify the diffusion of CO_2 within the storage reservoirs. Therefore, the objectives of this paper are to (i) investigate the impact of pore size and pore geometry of kerogen and clay structures on the diffusion of CO_2 and CH_4 gases under different pressure conditions, (ii) investigate the impact of brine and hydrocarbon saturation on the CO_2 diffusivity in different components of organic-rich mudrocks, and (iii) quantify the coupling effect of CO_2 adsorption/diffusion in kerogen and clay nanopores on the apparent gas permeability.

We used realistic kerogen molecular models of different types (e.g., type I, II, and III) and thermal maturity levels. The kerogen models were developed using the restrained simulated annealing process to investigate the impact of different pore geometries (e.g., circular pores with different aspect ratios) on the adsorption and diffusion behavior of CO_2 molecules. Meanwhile, we modeled a variety of clay types (e.g., illite, kaolinite, and montmorillonite) with different surface charges, molecular structures, and pore sizes. The developed kerogen and clay structures were then used as inputs to non-equilibrium molecular dynamics (MD) simulations with CO_2 particles. Next, we quantified the CO_2 diffusion and transport coefficients under different pressure and temperature conditions. We then investigated the impacts of reservoir fluids (e.g., brine and hydrocarbons) on the movement of the injected CO_2 particles by performing simulations at a wide range of fluid saturations. Finally, we quantified both the surface and the bulk gas diffusion coefficients in the three Cartesian coordinates to describe the directional diffusion tensor across the pore surface and into the bulk gas volume. Once the actual diffusivity value was determined, we used it to calibrate the apparent gas permeability models, which are used to describe the gas flow in nanopores.

Results showed that kerogen geochemistry has a significant impact on the diffusion behavior of CO_2 particles in kerogen nanopores. Changing kerogen type from type IA to type IIIA led to an increase in the CO_2 diffusion coefficient by 21% at a pressure of 20 MPa. Moreover, increasing reservoir temperature from 300 to 400 K led to an increase in the CO_2 diffusion coefficient by 65, 56, 150, and 73% for kerogen types IIA, IIB, IIC, and IID, respectively, at a pressure of 10 MPa. Unlike temperature, increasing reservoir pressure showed an inverse impact on the CO_2 diffusion coefficient. Increasing pressure from 1 to 20 MPa led to a decrease in the CO_2 diffusion coefficient by 21, 9, 15, and 20% for kerogen type IIA, IIB, IIC, and IID, respectively, at a temperature of 400 K. These findings highlight the significant impact of the reservoir geochemistry, temperature, and pressure on the diffusion behavior of CO_2 in organic-rich mudrocks. Therefore, carrying out reservoir pressure, temperature, and geochemical screening is essential for prospective CO_2 storage projects. The outcomes of this paper enhance our understanding of the diffusion process, which is crucial for reliable assessment of the amount of CO_2 that can be safely and securely stored in subsurface reservoirs. The diffusion of CO_2 in organic-rich mudrock formations can also impact the geological sealing properties of the rock. If CO_2 can diffuse through the kerogen and clay pores, it may increase the risk of leakage, potentially compromising the integrity of the storage site.

Shallow Aquifer Sampling for Carbon Capture and Storage (CCS) – Development of a Low-Toxicity Tracer to Enable Low-Contamination Water Sampling in a Water-Based Mud (WBM) System
Michael Taplin, BP; Emilie Peyret, SLB; Phillip Jackson and Kirsty Hitchen, BP

Aquifer water samples are a key component of carbon capture and sequestration (CCS) site characterization and are required in many jurisdictions. Often, these formations must be drilled with a water-based mud (WBM) system due to the proximity to the sea or the potential for potable water. To obtain high-quality aquifer samples using a WBM, an environmentally acceptable mud system was developed with a tracer chemical to monitor the sample pumpout. This system was successfully deployed in a shallow aquifer sampling job using a wireline formation tester.

The Northern Endurance Partnership (NEP) project is planning to store CO_2 in the Bunter Sandstone aquifer in the Southern North Sea (SNS). As part of site characterization, a shallow aquifer sample (at approximately 200 m BML) was required to characterize the fluid properties in the wider Bunter Sandstone aquifer. As no fluid data existed in the area, the composition of the water was unknown. A jack-up rig was obtained to drill a short borehole into the aquifer to allow the collection of fluid samples on wireline. Due to the shallow depth, it was deemed likely that the Bunter Sandstone is in hydraulic communication with the sea at this location. Therefore, common techniques for monitoring sample cleanup, such as resistivity, could not be used with certainty. To obtain low-contamination samples a tracer would need to be deployed. Tracers typically used in deeper reservoir sections are not acceptable for use in hydraulic communication to the sea, so an environmentally friendly tracer was required to be developed. Several chemicals were tested for their ability to be successfully built into a WBM formulation while also being able to model their concentration accurately using an advanced downhole fluid analyzer through optical density and/or fluorescent properties. This allows the chemicals to act as a tracer to monitor the sample contamination in real time during the wireline job. Chemicals were made up and tested in the operator’s laboratories before being sent to assess suitability through workshop tests with an advanced downhole fluid analyzer. The best-performing tracer chemical was added to the entire circulation system of the drilling rig and deployed in a water sampling job in a shallow borehole in the SNS.

Low-contamination (< 3%) water samples were successfully acquired at four depths. These results were verified by comparison with a deuterium oxide tracer (which can be tested in the laboratory only), whole core water samples, formation pressure gradients, and wireline log analysis. The data were then used as part of the project’s environmental statement submission (United Kingdom regulatory permit). The tracer deployment was highly successful, and the operator is expecting to deploy the chemical again in other projects.

FORMATION TESTING – RESERVOIR DYNAMICS AND FLUID CHARACTERIZATION

Asphaltene Characterization Using Downhole Fluid Mapping While Drilling – Fluid Characterization Case Study for Completion Optimization
Yon Blanco and Julian Pop, SLB; Rolando di Primio and Oyvind Stiro, AkerBP; Scotty Paul, Velerian Sanjao Lopez, and Marat Khaziev, SLB

A novel workflow is presented where logging-while-drilling downhole fluid analysis (LWD-DFA) data are combined with surface mudlogging to identify and quantify asphaltene distribution in the development phase of a North Sea field known to have complex fluid variations and compartmentalization. Data from two pilot wells were used for calibration and validation of optical densities from LWD-DFA and wireline downhole fluid analysis (WL-DFA) acquired in wells drilled during the appraisal phase vs. historical laboratory-measured asphaltene data. Subsequently, three horizontal producer wells were drilled, and the new validated/calibrated LWD-DFA data were used for fluid characterization and asphaltene distribution mapping in real time, enabling decisions for drilling and completion design.

To de-risk and resolve this fluid variability and compartmentalization in the three horizontal production wells in the field development plan, a digitally enabled workflow coupling surface logging techniques with LWD-DFA was implemented. Identification of the presence of heavy hydrocarbon components (asphaltenes) and their mobility was of paramount importance. Continuous composition measurements were obtained via advanced mud gas chromatography to identify the heavier components and were further supplemented by fast field total organic carbon (TOC) analysis at discrete depth intervals. This rich data set, when merged with petrophysical LWD data, allowed fluid analysis station depths to be optimally selected and analyzed with LWD-DFA-based optical spectrometry.

Historical laboratory data and wireline DFA data were used to build correlations between optical densities at different wavelengths and the asphaltene content in wt%. These correlations were first validated while drilling two pilot wells and then utilized while drilling the three horizontal producers. Using these correlations, LWD-DFA optical densities obtained at each selected fluid analysis depth were used to predict asphaltene distribution along the well trajectories while drilling. Dynamic parameters during the pumping/cleanup phase of the LWD-DFA stations, such as pressure drawdown, gas-oil ratio (GOR), composition, optical densities, resistivity, and temperature, were monitored and controlled in real time to reach the targeted level of contamination and collect high-quality single-phase samples for further fluid analysis in the laboratory.

The asphaltene real-time data became critical during the drilling of the producer wells for completion design. High-quality fluid composition data, as well as physical single-phase hydrocarbon samples, were acquired with the integration of surface logging, advanced petrophysical measurements, and downhole fluid analysis in the reservoir section of each producer well. Moreover, the newly acquired data were integrated with previously acquired wireline DFA measurements in neighboring wells to evaluate variations in fluid properties measured in situ, particularly modeling asphaltene content gradients with the Flory-Huggins-Zuo (FHZ) equation of state to investigate vertical and lateral connectivity. Clear demarcation of the various compartments observed in the appraisal wells was achieved to successfully de-risk drilling and completions operations.

The examples show the value of applying LWD-DFA to characterize fluid distribution in horizontal well trajectory and its ability to complement existing well placement workflows to optimize reservoir exposure, all done while drilling. Field development decisions are enabled in the while-drilling phase to optimize well and completion design and serve to further refine subsequent well placement.

Combination of Borehole Image Logs and Downhole Fluid Analysis Logs to Assess Reservoir Connectivity
Oliver C. Mullins, SLB; Bernd Ruehlicke, Zbynek Veselovsky, and Carsten Vahle, Eriksfiord; Peter Schlicht and Robert J. Laronga, SLB; Brandon Thibodeaux and Bilal Hakim, Talos

Reservoir connectivity remains one of the most significant risk factors of reservoirs; unrecognized compartmentalization is one of the most important origins of reservoir underperformance globally. Pressure communication is a necessary but insufficient condition to establish flow communication because pressure communication requires almost no mass transport. Well testing is certainly a powerful method to address connectivity; however, well testing in many settings is very expensive, limiting its application. In addition, well testing of limited duration suffers from limited depth of investigation, reducing the benefit associated with the cost. An improved methodology is needed to assess reservoir connectivity prior to production while the value of information is high.

Here, a multiphysics, well-log workflow is employed on a reservoir to address reservoir connectivity at the earliest stages of reservoir evaluation. Often, the image logs and downhole fluid analysis (DFA) logs are acquired in the normal course of exploration and appraisal; these interpretation methods require little additional marginal cost. Moreover, new reservoir and well-log data can be placed within this framework deep into development. The combination of image log data and DFA from the discovery and early appraisal wells is used to address reservoir connectivity and other key attributes of the reservoir. High-resolution image logs enable geologic interpretation of geobodies. Correspondingly, DFA data can be placed within the context of reservoir fluids geodynamics, enabling a coherent evaluation of the evolution of fluids as well as their geobody containers over geologic time. In this case study, there are two stacked sands that make up the reservoir, and their possible lateral connectivity and vertical connectivity are fundamentally important to assess early in the evaluation process.

From the image log evaluations, the large-scale sedimentary system of the reservoir represents a sand-rich basin floor fan or series of fans over the reservoir units. The basin floor fans are comprised of confined and unconfined episodes, which occur in response to periodically changing axial vs. off-axis positions within the governing fan. The lower sand was deposited in a medial, channelized sand-rich fan to channel-to-sheet transitional zone. The upper sand is interpreted as a channelized, axial lobe system. The large-scale structure that emerges is that the T_1 and T_1ST are on one channel axis, and T_1ST and T_2 are on a second channel axis. Both these interpreted settings are consistent with isopach image analysis and bode well for potential lateral connectivity.

The DFA data indicate that the asphaltene gradients in the T_1 and T_1ST wells are equilibrated laterally in each sand, thus consistent with lateral connectivity. However, the offset between the asphaltene gradients in the upper and lower sand indicates limited vertical connectivity. The T_2 well is in a downthrown block; when reconstructing the reservoir and asphaltene gradients prior to fault throw, it is evident that the upper and lower sands were connected across these three wells at the time of charge and prior to fault thrown but not in present day. Subsequent lab data on the fluids and production data confirmed all major conclusions from the early multidiscipline analysis. This multiphysics workflow on the earliest log data available in the reservoir enables the development of different scenarios that guide subsequent data acquisition and development concepts.

Disparate Fluid Distributions of Stacked Gas-Washed Reservoirs Are Successfully History-Matched via Forward Modeling of Fluid Mixing Processes

Tarek S. Mohamed, The University of Texas at Austin; Morten Kristensen, SLB; Carlos Torres-Verdín, The University of Texas at Austin; Oliver C. Mullins, SLB

Three stacked reservoirs in the deepwater Gulf of Mexico received similar oil and gas charges, yet they were subject to different reservoir fluid geodynamics (RFG) processes that led to entirely different present-day fluid distributions: a near-critical condensate in the upper zone, black oil in the middle zone, and dry gas in the lower zone. Extensive wireline logs and fluid data analysis show that the three zones initially contained oil, then received a large influx of biogenic gas that led to gas-washing processes. Oil-filled fluid inclusions and precipitated asphaltene inclusions are found in the gas-filled lower zone, suggesting that oil first arrived before gas charged the reservoir. Our objective is to use compositional reservoir simulation to model the fluid mixing processes over geologic time, constrained by wireline logs and fluid data, to explain and reproduce present-day complex and spatially variable fluid distributions across the stacked reservoirs.

Mixing of oil and gas charges involves various mass transport processes and rock-fluid interactions, leading to the present-day spatial distribution of fluid properties. Wireline logs and fluid data are vital to describe complex mixing outcomes. The middle zone exhibits extreme gas washing in the crude oil with a methane-to-ethane mole ratio of 70 and a methane carbon isotope of –67%. Thus, the solution gas is 90% primary biogenic gas. However, the oil in this zone only has a gas-oil ratio (GOR) of 1,000 scf/bbl, precluding a process of preserved massive gas addition to this moderate maturity oil ($T_s/(T_s + T_m) = 0.63$). Additionally, there is no way this Neogene formation degassed the thermogenic gas in the geologic past. The only plausible explanation for these observed fluid properties is that the oil in the middle zone was gas-washed by added primary biogenic gas. The upper zone contains a high GOR oil with a gas cap. We model gas-oil mixing dynamics in the middle zone, driven by a point gas charge into undersaturated oil and leading to the present-day oil state. In the examined reservoirs, fluid mechanics evaluations and modeling results indicate that biogenic gas arrived after the oil charge. Moreover, the petrophysical evaluation indicates that the middle zone consists of main and stray sandstones, which are connected but baffled. There is a compositional offset of oil between the two sandstones, which must be accounted for by compositional simulation. We investigate gas-liquid equilibria, convective and diffusive mixing dynamics, as well as the effects of baffles and mechanical subsidence on compositions of liquid and gas phases.

We describe how the complex fluid distribution in the middle zone was developed over geologic time by simulating the mixing of fluid charges and matching current fluid measurements. The following sequence of RFG processes is modeled: an undersaturated black oil reservoir with dissolved thermogenic gas receives a primary biogenic gas charge. Simulations indicate excellent convective mixing and rapid dissolution of the added biogenic gas into oil. As gas addition continues, the oil reaches saturation, and the excess gas forms a gas cap, while added methane gradually strips thermogenic gas (C2-5) from the oil, which rises to the top, thereby increasing the thermogenic gas fractions in the gas cap. The expanded gas cap leads to seal failure and leakage of the thermogenic and biogenic gas mixture. Eventually, biogenic gas largely replaces solution thermogenic gas in the oil. Additionally, asphaltene onset pressure (AOP) increases, and some asphaltene cluster formation occurs, leading to a bimodal asphaltene distribution. Subsequently, the reservoir subsides, and the increased pressure and temperature lead to diffusive mixing of the gas cap into the oil column. Modeling of reservoir charges over geologic time is a powerful new way to reproduce present-day complex fluid realizations and enhance reservoir description.

Enlightening Reservoir Fluid Distribution and De-risking Brownfield Development With the Combination of Downhole and Surface Fluid Mapping Services

Aldrick Garcia Mayans, Alan Keith Fernandes, Andrea Di Daniel, Aleksandar Gligorijevic, and Ivan Fornasier, SLB; Siti Najmi Farhan Bt Zulkipli and Calvin Lowrans, PETRONAS Carigali

Fluid characterization in mature fields is rendered complicated due to complex wellbore profiles, challenging acquisition conditions such as increased risk of differential sticking, wellbore degradation, and uncertainties associated with fluid distribution and movement. In this study, we introduced a novel method of enhanced real-time fluid characterization combining advanced mud gas logging (AMG) with downhole fluid mapping while drilling (FMWD). While a typical approach consists of solely optimizing depth and station selection for formation testing, this workflow leverages the strength of both technologies to reduce stationary time while increasing data quality.

Field X is a mature brownfield offshore Malaysia with some heavily depleted zones and with gas injection effective in other layers. This leads to large uncertainties in fluid contacts and fluid types across the reservoir zones. Due to faulting and incertitude on the reservoir structural dipping dip, there are uncertainties in the reservoir lateral and vertical continuity. Additionally, drilling through Field X is complicated due to the geological reservoir behavior posing wellbore instability issues and causing stuck pipe events.

To mitigate the uncertainty in the fluid contacts, a highly deviated pilot is drilled across the gas cap, oil rim, and water leg prior to sidetracking and geosteering the horizontal drain. The reservoir has a low-resistivity contrast between gas, oil, and water, making classical petrophysical evaluation unreliable. An FMWD tool is therefore used in the pilot. However, limiting the stationary time during FMWD operation is necessary to mitigate stuck pipe risks. Therefore, the operator decides to limit fluid acquisition by reducing stationary time to a minimum and only performing basic fluid identification (gas/oil/water) as opposed to advanced fluid characterization and sampling.

While drilling the pilot hole, AMG is deployed to identify continuous fluid distribution in the drilled intervals. These data are first used to optimize depth selection for FMWD stations. While typical workflows stop here, an innovative workflow was adopted in which AMG was used at the surface during FMWD pumpout stations. During FMWD operation, mud circulation is necessary to power up the tool, maintain data transmission, and circulate out residual hydrocarbons expelled in the borehole. This offers a unique opportunity to allow AMG to evaluate the live reservoir hydrocarbon during FMWD operations.

Individually, both services are designed to characterize the fluid in the reservoir. However, to go from basic fluid identification (gas/oil/water) to advanced fluid characterization (gas-oil ratio, composition) with a high level of certainty, formation testers need to clean up, that is, to pump out until contamination from mud filtrate is reduced to an acceptably low level. AMG analyzes live reservoir hydrocarbon extracted from the mud, regardless of how small the quantity of hydrocarbons reaching the surface. While the service is mostly used on fluids released during the drilling process, it can be used with the fluids released by the FMWD tool. Tested in one well in Field X on six pumpout stations at three different depths, the combination of both services offered a unique perspective on the reservoir. AMG provided the first hydraulic unit distribution while drilling. FMWD confirmed pressure regimes, producibility, and movable phase indication. Utilizing AMG during the FMWD operation allowed meaningful characterization of the hydrocarbons and accurate comparison to the original PVT data that has been treated for variations in mud flow.

The integration of both services, as opposed to using them separately, was successfully deployed in one well of Field X. This dual technology approach allowed accurate fluid characterization while maintaining short stationary time and maximizing pumpout volume.

Estimation of Permeability From Electrical Resistivity Response Determination in Carbonate Rocks From the Sergipe Sub-Basin

Marcus Vinícius Corrêa, Maria Rosilda de Carvalho, Fernando Sergio de Moraes, and Victor Hugo Santos, CCT/LENEP/UENF/INCT-GP

In this theoretical-experimental study, we investigate the connections between real and complex electrical resistivity laboratory measurements and their relationships with reservoir parameters in carbonate rock samples. Real resistivity is typically assumed to result from direct current measurements, and its relations to reservoir parameters are described by Archie-type models. On the other hand, complex resistivity arises from electrical current measurements spanning from 1 to 100 kHz, and as of now, its relations to reservoir parameters have not been firmly established. In this multifrequency range, the medium becomes electrically polarized when small fractions of clay or metallic minerals are present.

Building on this premise, we conducted measurements of both real and complex electrical resistivity on 13 carbonate rock samples from the Sergipe sub-basin. We fitted amplitude and phase curves using the Dias and Hybrid models. However, the original Dias model struggled to adequately fit the phase curves in the intermediate frequency spectrum, likely due to the presence of heterogeneities within the rock samples. The Hybrid Model proved to be more successful in addressing this issue. The Archie coefficients that we derived from the models are associated with the resistive response of the sample's pore network and the relatively weak cementation, as confirmed by thin-section analysis. The observed polarization effect in the laboratory data from these 13 carbonate samples was effectively modeled. We attribute the observed induced polarization (IP) effect primarily to the low concentration of clay minerals, which is reflected in the low intensity of the first phase maximum.

Subsequently, we explore the potential connections between the estimated model parameters and the laboratory data concerning reservoir properties. The estimation of permeability using the Dias model parameters is based on the relationship between grain diameter and cation diffusion relaxation time in the solution. The electrochemical parameter is determined by the thickness of the electrical double layer, which is linked to the relationship between relaxation time, mineral grain diameter, and cationic diffusion coefficient. To ensure the reliability of our estimates for the permeability of the studied system, we compared the permeability values obtained from both the Dias and Hybrid parameters, taken at the first phase peak associated with ion diffusion, with the laboratory measurements. This comparison was conducted using percent error analysis, confirming the accuracy and dependability of our permeability estimates for the examined system.

Integrating Dual-Flowline Fluid Property Measurements for Guided Focusing and Cleanup Monitoring During Fluid Sampling

Melton Hows and Thomas Pfeiffer, Shell Exploration and Production Co.; Richard Jackson, Kai Hsu, Hua Chen, Evgeniya Deger, and Jules El-Khoury, SLB

Acquiring clean reservoir fluid samples lays the foundations for robust fluid characterization for input to decision making during field appraisal and field development planning. Focused sampling techniques for wireline formation testers, which were introduced in 2005, represented an important breakthrough in downhole fluid sampling since it enabled the capture of clean and representative reservoir fluid samples much faster than with conventional sampling methods. However, the results of focused sampling and its performance can sometimes vary widely depending on factors such as technique and operational control.

In this contribution, we describe techniques to monitor focused fluid sampling and methods to determine the efficiency of focused sampling by utilizing the dynamic responses of reservoir fluid flow in a dual-flowline formation testing system during fluid sampling operations. The method integrates downhole fluid analysis measurements, which are acquired simultaneously from both the sample and guard flowlines during sampling operations.

Multiple fluid property measurements are available to monitor both flowlines during formation testing and sampling operations. The hardware components, such as the light source, optical filter arrays, photodetectors, and electronics, are the same for both flowlines. Randomized optical fiber bundles connect the spectrometer to the individual flowlines. This configuration limits hardware bias between the two flowlines and enables new opportunities for integration between the fluid property measurements, which are acquired simultaneously on both flowlines.

The success of focused sampling can then be less dependent on skill and experience by improving monitoring and controlling the efficiency while adjusting the flow rate ratios and pressure drawdowns for the sampling pump modules. These techniques are compatible with conventional focused and three-dimensional (3D) multi-drain-focused sampling probes, which can further expand the operating envelope for fluid sampling and fluid property measurements in reservoirs with wider ranges of permeability and reservoir fluid type.

In this paper, we provide two case studies to illustrate the method. Field examples are reviewed to show the practical utility of quality control and monitoring of the efficiency of focused sampling. The integration and analysis of dual-flowline sampling measurements provide new insights to improve the assessment of dynamic behavior and responses during sample cleanup. We also propose the use of new indicators for determining oil-based mud contamination, which can be used for input to better decision making in reservoir fluid sampling and formation testing operations.

Raman Spectroscopy for Gas Composition Analysis With a New Logging Tool for EOR, New Energy, and Scope 1 Applications

A. Ballard Andrews and Andrew Speck, SLB

A new logging tool prototype enables a suite of applications for high-value multizone gas wells that can be part of a larger strategy of increasing the recovery factor of the entire asset and reducing Scope 1 emissions. From the production history, it may be uncertain which perforations are the source of compositional changes due to commingling. The new logging tool enables gas composition analysis on a zone-by-zone basis.

In formations that intersect sand bodies with variable CO_2 content, zones with higher CO_2 content lower the net caloric content of production. Zonal composition identifies sand bodies with higher CO_2 concentrations, which can be shut in, resulting in more CO_2 being sequestered downhole, thereby reducing Scope 1 emissions and costs. When lean gas (methane) is pumped into an injector well to sweep liquid condensate, breakthrough can occur. By measuring the ratios of compositional components at each depth, the inflow points can be identified and shut in with a plug, resulting in less compressed gas or other sweeping agents being returned to the surface and reducing costs and Scope 1 emissions due to leakage.

Salt caverns are limited in size and geographical distribution and cannot meet the anticipated global demand for hydrogen storage. Depleted oil and/or gas reservoirs could be used for hydrogen storage, but many technical uncertainties must be addressed. Compositional changes can occur due to chemical reactivity, microbial activity, and differential leakage, resulting in irrecoverable loss. These processes are complex and difficult to model on the reservoir scale, but since gas mixing is slow relative to the cycle times for injection and withdrawal from storage, compositional changes can be localized.

A high-temperature solid-state laser was developed for Raman spectroscopy to measure the molar concentrations of methane, ethane, propane, carbon dioxide, nitrogen, hydrogen, and water in the far-infrared (FIR) "fingerprint" region of the electromagnetic spectrum (3 to 25,000 μm). Backscattered photons are collected in a collinear geometry, obviating the need for an internal flowline and enabling continuous and/or station logging without a formation seal. A calibration file and inversion algorithm are used to calculate the gas composition in the borehole on a zone-by-zone basis.

Natural gas mixtures were measured, and mole fraction errors (MFE) were calculated over a range of pressures. Molar concentration errors were averaged from all mixtures and converted into errors in partial pressures assuming an ideal gas law and a temperature of 25°C. From the known temperatures and pressures of exemplary gas fields, we predict the MFE accuracies we expect to achieve for the instantaneous signal if the tool is run in the fields. For gas field applications with pressures above 3,000 psi, the MFE in continuous logging mode is ~2% for methane and ~1% for ethane, propane, nitrogen, and carbon dioxide. For pressures from 1,500 to 3,000 psi, the MFE is larger, but with station logs, statistical averaging can achieve errors of less than 1% for all components after 1 hour.

Raman spectroscopy enables continuous gas composition logging without a formation seal. In-situ zonal composition measurements are key to achieving targeted well interventions, solving the reservoir challenges outlined above, and enabling a host of applications for enhanced oil recovery (EOR), new energy, and reduction of Scope 1 emissions.

Real-Time Fluid Monitoring and Classification Using Downhole Spectrometer Measurements
Kai Hsu, Richard Jackson, Hua Chen, Evgeniya Deger, Yoko Morikami, and Jules El-Khoury, SLB

To evaluate and analyze the characteristics of fluids within hydrocarbon reservoirs, it is critical to collect representative fluid samples. For this purpose, the application of formation testing and fluid sampling with downhole fluid analysis is now well-established in our industry. In this paper, we introduce a new approach and methodology for the real-time analysis and visualization of crucial fluid properties, which are measured while conducting formation testing and fluid sampling operations. This method employs an eigenspace projection, utilizing the reservoir fluid spectral measurements acquired by downhole spectrometers in a dual-flowline formation tester. The eigenspace is derived from an extensive global fluid spectral database, which represents a wide range of hydrocarbon reservoir fluid types.

The proposed method combines machine-learning techniques with artificial intelligence. Initially, the prediction model is trained using a comprehensive global spectral database, which includes approximately 500 fluid spectra from a diverse set of hydrocarbon samples. The spectral measurements have been acquired under various pressure and temperature conditions, with samples that represent a wide range of hydrocarbon composition and PVT properties. The training method involves performing singular-value decomposition (SVD) on the spectral data within the database. A model is then constructed by retaining the first and second eigenvectors (also known as principal components) derived from the SVD. The SVD approach is a well-known technique for uncovering the dominant features concealed within data, often revealing key factors and parameters to help characterize the reservoir fluid data under consideration.

Once the model is established, the prediction phase involves projecting the real-time spectrometer measurements onto the first and second eigenvectors. By plotting the projection of the first eigenvector against the projection of the second eigenvector, we can determine the state, fluid type, and dynamic evolution of fluid properties within the formation tester flowlines during sampling and testing operations. Subsequently, a multitude of applications for this method can be considered for use in fluid sampling and evaluation of sampling measurements.

The application of this new method offers a range of significant applications. It allows for the discrimination between hydrocarbon and non-hydrocarbon fluids, such as water, mud, and contaminants, as well as the identification of pure hydrocarbon fluids within oil-water mixtures. Moreover, by crossplotting the projection data, it establishes a clear separation among various types of hydrocarbon fluids, such as black oil, volatile oil, gas condensate, wet gas, and dry gas, forming the foundation for real-time fluid classification. These distinctions also facilitate the identification of oil-based mud (OBM) filtrate based on distinct projection angles. Additionally, the evolving data projections over time closely correlate with the gas-oil ratio (GOR) of hydrocarbon fluids in the flowline.

Furthermore, within a dual-flowline formation tester, this method also allows for the determination of which flowline contains cleaner fluid and provides a means to monitor the progress of sample cleanup with indicators to help control and optimize the sampling process.

In this paper, we provide concrete illustrations of these applications through field examples. These field examples will also serve as invaluable case studies, showcasing the tangible advantages and outcomes achievable through the application of the proposed methodology.

GEOSTEERING / UDAR WELL PLACEMENT FOR OPTIMAL COMPLETION

A Fast Forward Modeling Method for Gamma LWD Using 1D Equivalent Integral in High Inclination or Horizontal Well

Cairui Shao and Zhiqiang Ma, China University of Petroleum (East China); Miantao Yu, China Oilfield Services Limited

During logging-while-drilling (LWD) geosteering, comparing the forward gamma logging response with the real one is one key technology to determine the real formation mode. As the Monte Carlo method is too slow to meet the real-time need of forward modeling, it is also difficult to deduce analytical expressions for gamma logging response in high inclination or horizontal wells. Therefore, it is a challenge to find a fast forward modeling method for real-time applications of gamma LWD. The author once invented a fast forward modeling method using three-dimensional (3D) partition integral in high inclination or horizontal wells, but the algorithm is somewhat complex to apply. Therefore, the author invents a new one-dimensional (1D) integral fast forward modeling method, which overcomes the difficulty of real-time gamma forward modeling.

The principle of this method is to take the gamma ray flux received by the detector in an inclined or horizontal well as a 1D equivalent integral problem under vertical well conditions, including three key points. (1) First, take the total gamma rays received by the detector, equivalent to that from sphere space with effective detection radius r0. Within the sphere space, obtain the integral expression φ(r0, z) of the gamma ray flux under vertical well conditions, which is a function of the distance z between the formation and detector center. (2) Then, using the numerical integral results of φ(r0, z) to fit a double exponential function varying with the distance z. After normalization, get the 1D longitudinal equivalent contribution coefficient gz of the formation’s gamma ray under vertical well conditions. (3) Finally, using the effective detection radius r0 of the gamma ray detector, determine the main contribution sphere space of gamma rays from the formation. Moreover, calculate the distance z between the detector and the formation within the sphere. Then, along the formation normal direction, using the 1D gz as the contribution coefficient, integrate the gamma ray flux of formation contribution and get the forward value.

Figure 1a shows the forward results at different angles between wellbore trajectories and formation model, which using the 1D equivalent integral method and the 3D sphere space partition integral algorithm individually. In Fig. 1a, the dashed line in step shape represents the formation gamma ray model; other different types of lines are obtained using a 3D integral, and scattered points with different shapes are obtained using a 1D integral. We can see that at the same angle between formation and wellbore trajectory, the forward results of the two methods overlap together, just with an average relative error of about 1%, verifying the correctness of the 1D method. Figure 1b is a demonstration using the 1D fast forward modeling for bed-boundary identification. The target layer is a shale gas zone with mud interlayers. The upper and left sides show the LWD curves indexed on horizontal displacement and vertical depth of the wellbore trajectory. RGR (blue color) is the real gamma LWD curve, and FGR (red color) is the fast forward gamma curve. The lower right area shows the vertical profile of the formation model and wellbore trajectories; the red one represents the actual trajectory, and the blue one represents the designed trajectory, which is along the maximum horizontal displacement direction of the wellbore. The FGR shape is consistent with the RGR overall, indicating the correctness and effectiveness of the method for real-time formation model identification and adjustment. These results show that the 1D equivalent integral method has high efficiency and is more convenient than the 3D one, without the complex division of 3D sphere space, can meet the real-time requirements of forward modeling, and provides an algorithm foundation for fast inversion.

Dielectric Permittivity From LWD Electromagnetic Measurements – Methods Comparison and Results Validation

Salah Al-Ofi, Baker Hughes; Shouxiang (Mark) Ma, Saudi Aramco; Jun Zhang, Baker Hughes

Extracting formation dielectric permittivity from LWD electromagnetic (EM) measurements has been an area of special interest recently, and as a result, a special session on the subject was conducted at the SPWLA 64th Annual Symposium. This study continues and extends that effort by comparing LWD EM-derived dielectric permittivity from three methodologies and validating them in comparison with wireline measurements conducted in much higher frequencies. A secondary objective of this study is to evaluate the possibilities of deriving dielectric permittivity from a unique ultraslim LWD EM tool for improved geosteering in drilling ultraslim wells, such as underbalanced coil tubing drilling when geosteering measurements are limited.

In this study, several methods are evaluated in obtaining dielectric permittivity from LWD EM measurements in 400 kHz and 2 MHz frequencies; Method 1 is complex refractive index model (CRIM-based), Method 2 is an analytical resistivity-based approximation (RBA), and Method 3 is a dielectric-independent inversion (DII). The resulting dielectric permittivity from the three methods is then compared among themselves and integrated with wireline dielectric measurements across the 10-MHz to 1-GHz frequency range to verify the dielectric dispersion relationship. Results validations are also performed by comprehensive log correlations, including the LWD triple combo and the water-filled porosity interpreted from wireline data.

Vertical and horizontal well LWD dielectric permittivities are obtained by using the methods described. Results show that all methods can provide dielectric permittivity within a reasonable range of uncertainties. Among the three methods, the CRIM-based method seems to perform better as its results show clear independence with resistivity logs and correlate well with wireline dielectric permittivity with consideration of dispersion, as well as water-filled porosity. Derived dielectric permittivity from the other two methods shows undesirable dependency with resistivity.

This is the first time to compare and validate LWD-derived dielectric permittivity from different methods, leading to a meaningful approach to utilize the dielectric properties estimated from LWD measurements for geosteering.

Energy and Spectrum of Transient Induction Measurements for Deep-Reading Looking Ahead
Pengfei Liang, Qingyun Di, Wenxuan Chen, Wenxiu Zhang, Xinghan Li, and Ranming Liu, Institute of Geology and Geophysics, Chinese Academy of Sciences

The total electromagnetic (EM) fields consist of the primary fields excited and propagated in the background model and the scattering fields reflected from the resistivity anomaly. As the resistivity anomaly is the detection target in the logging, it is advantageous to detect the resistivity anomalies by directly investigating the scattering EM fields instead of the total EM fields. The transient electromagnetics (TEM) method measures the scattering EM fields and is promising to largely enhance the detection of the resistivity anomaly layer ahead of the drill bit. However, it is impossible to directly process the time-domain TEM data downhole as the computational resource downhole is limited or transmit it to surface for further processing as the bandwidth of the borehole transmission system is limited. With developments in computational technologies, it becomes promising to process the frequency-domain TEM (FTEM) data downhole, as it requires less downhole computational resources than the time-domain TEM data. Thus, we apply the FTEM method to a borehole-conveyed logging tool for deep-reading look ahead.

We first define the energy of time-domain signals ($dB_z(t)$_dt) by implementing the Hilbert transform on it. Then, the time-domain original signals and their energy signals are transformed into the frequency domain for further investigation. Finally, we use attenuations of original signals and their energy signals in the frequency domain to detect the formation boundary ahead of the drill bit. They could provide formation information at very low frequencies and are of significant usefulness to detect a distant formation boundary ahead of the drill bit.

Moreover, we propose a theoretical instrument consisting of one transmitter sub and one receiver sub hanging in the top layer of a two-layer model, as shown in Fig. 1a. The transmission waveform is shown in Fig. 1b. The measurements of original signals in the time domain are shown in Fig. 1c, and the corresponding measurements in the frequency domain are shown in Fig. 1d. The energy signals in the time domain are shown in Fig. 1e, and the energy signals in the frequency domain are shown in Fig. 1f. The attenuations of original signals and attenuations of energy signals are estimated by the ratio of signals with different distances (3 to 40 m) between the receiver and the layer boundary and signals with a distance of 50 m and are shown in Figs. 1g to 1h, respectively.

Figure 1d shows that the original signals have a maximum amplitude of around 1k to 2k Hz, while Fig. 1f shows that the energy signals have a maximum amplitude of around 0 Hz. And the amplitude shown in Fig. 1f is larger than that in Fig. 1d. It reveals that the signals in the frequency domain could provide formation information at a much lower frequency, which is useful for detecting a distant formation boundary ahead of the drill bit.

Figures 1g to 1h shows the dynamic range of the signal attenuations is large, although that of original signals attenuations is a little smaller than that of energy signals. These two figures reveal that the attenuations of both signals in the frequency domain are sensitive to the formation boundary ahead of the drill bit. Furthermore, the depth of detection of the tool could reach more than 30 m ahead of the drill bit.

We show that such an FTEM tool may be used to image the formation boundary at comparatively large distances from the drill bit while keeping the tool itself relatively compact. Therefore, it would be instrumental in the optimal placement of a well in a hydrocarbon reservoir.

Exploring Propagation Resistivity Measurements With Two Receiver Pairs
Holger Thern and Jun Zhang, Baker Hughes

Propagation resistivity measurements have been the established method for deriving subsurface formation resistivity during logging-while-drilling (LWD) operations for more than 30 years. Traditionally, propagation resistivity is based on attenuation (AT) and phase difference (PD) from the combination of an axial receiver (Rx) pair and axial transmitter (Tx) pairs at sub or lower megahertz frequencies. Variations and refinements of propagation resistivity measurements over the years include increasing the range and the number of frequencies, the number of Tx, as well as the tuning of the Rx spacing and Tx positions.

A new concept of adding a second axial Rx pair operated at the same frequency as the existing Rx pair is introduced. The new tool configuration with a new third lower operating frequency results in improved data quality and expands the range of applications for multiple propagation resistivity (MPR) measurements. It also enables the exploration of the capability of a variety of different Tx-Rx pair combinations not available in the past. The six theoretically possible Tx-Rx pair permutations for four Tx and one Rx pair increase to 24 theoretically possible permutations for four Tx and two Rx pairs. The goal of the paper is to review and discuss the value added by some of the additional MPR measurement permutations, to illustrate their results by modeling and measurements, and to assess the added value for field applications.

The Rx spacing is directly related to the vertical resolution (VR) and signal-to-noise ratio (SNR) of the MPR measurement. While the short Rx spacing provides better VR for characterizing thin layers, the long Rx spacing delivers better SNR to extend the MPR resistivity range for providing high-accuracy measurements at high resistivity (HRHA). Meanwhile, a third depth of investigation (DoI) is achieved by matching selected Rx and Tx. The presence of four Rx also provides a great redundancy in case of an antenna malfunction. For example, the failed Rx can be reinstated by other available Tx-Rx combinations without having to introduce assumptions or approximations. Environmental correction charts are available when switching between all meaningful Tx-Rx combinations. The MPR key tool performance parameters VR, SNR, and resistivity accuracy are validated by modeling exercises, by data quality indicators (such as statistical noise) from the lab and in downhole applications, as well as by observations in field data. In summary, the concept of a second Rx pair introduces previously unavailable processing options and applications. The additional deliverables with superior data quality ultimately lead to improved formation evaluation and well placement applications.

High-Resolution 3D Reservoir Mapping and Geosteering Using Voxel-Based Inversion Processing of UDAR Measurements
Saad Omar, Diogo Salim, Mikhail Zaslavsky, and Lin Liang, SLB

Ultradeep azimuthal resistivity (UDAR) measurements provide full three-dimensional (3D) volumetric sensitivity to the surrounding formation and are routinely used for strategic geosteering, reservoir navigation, reservoir characterization, and real-time drilling decision making based on the inverted resistivity profile. The initial layered-earth-model (1D) reservoir map can be further refined (on demand) with two-dimensional (2D) and 3D processing. Existing 3D processing, employing octree gridding for modeling and inversion, leads to extreme smoothing in the formation mapping with artifacts appearing away from the wellbore, thereby compromising the higher resolution and superior accuracy of 2D imaging inversions (either along the wellbore to image longitudinal discontinuities or at an arbitrary alignment angle with the wellbore to image lateral). High-resolution and accurate 3D reservoir mapping is thus critical for delivering precise drilling performance to increase asset recovery, improve wellbore quality, reduce overall well construction costs, and optimize production.

In this paper, we present a new voxel-based processing method that provides sensitivity-driven, high-resolution 3D deep resistivity profiles and is, therefore, able to map arbitrary 3D reservoir heterogeneities. The minimally biased algorithm uses a non-uniform 3D voxel discretization of the imaging plane and the full 3D sensitivities of deep-directional resistivity measurements to map the 3D resistivity distribution. A full 3D electromagnetic simulator modeling arbitrary geometry and anisotropy (with exact gridding) is used in the inversion loop to accurately reconstruct the response, and preserving the resolution with an adaptive regularization enforces consistency and avoids data overfitting. In addition, a structure similarity regularization enhances the obtained anisotropy from the inversion process. The increased complexity of formation reconstruction from 1D to 3D requires not only sophistication in algorithmic development but also in tool measurements.

The inversion has been validated on several 3D synthetic scenarios with various complexities, including avoiding laterally occurring shale bodies, imaging laterally displaced multifingered sand injectites, and laterally imaging residual oil bodies in shaly environments. The 3D processing preserves the resolution and interpretation consistency with 1D and 2D processing and successfully enhances the imaging of the approaching heterogeneities by quantifying their dimensions and orientation with respect to the wellbore. The workflow has also been applied to multiple deep-directional resistivity field data sets, demonstrating the ability to map arbitrary 3D heterogeneities with high resolution and precision.

Improved Detection and Description of 3D Sandstone Injectites in the Grane Field, Central North Sea via 1D Stochastic Inversion of UDAR Measurements

Nazanin Jahani, NORCE Norwegian Research Centre; Carlos Torres-Verdín, The University of Texas at Austin

The Grane Field in the central North Sea presents technical challenges due to sandstone injectites within shale formations above the main sandstone body and commonly offset from the well trajectory. The standard approach of implementing one-dimensional (1D) inversion of ultradeep azimuthal resistivity mapping (UDAR) measurements can mask and/or deleteriously alias the influence of these three-dimensional (3D) sandstone injectites when not using a dimension-discriminant approach in the inversion algorithm. Such a limitation can result in sizable errors in predrilling planning and real-time well placement, including mud loss circulation near unstable shale formations. While 3D inversion is an option for interpretation, it remains computationally intensive and, hence, is not commonly used in real-time well-geosteering applications. UDAR measurements inherently provide discriminant information about the 3D object's spatial location relative to the well trajectory. Some components of the measurement tensor exhibit better sensitivity for detecting 3D objects penetrated and/or offset from the well trajectory, consequently leading to improved data misfit for those components during the 1D inversion process. Our objective is to develop a method to detect and quantify 3D objects offset from the well trajectory by analyzing differences in data misfit among various subsets of the EM measurements or geosignals during 1D inversion. For instance, we aim to determine whether 3D objects are intersected by the well trajectory or are offsets from it. Unaccounted 3D objects in the inversion process can deleteriously bias 1D curtain inversion results, hence affecting well navigation. The discriminant method developed in this paper enables one to conduct selective and adaptable 1D stochastic inversion of UDAR measurements, ultimately defining the orientation, geometry, and distance to sandstone injectites located away from the well trajectory within the Grane Field.

Our method consists of the following steps: (1) we conduct comprehensive 3D forward modeling and sensitivity analysis of UDAR measurements when 3D objects (1a) intersect the well trajectory and (1b) are offset from the well trajectory. This step aims to enhance our understanding of UDAR measurement sensitivity to 3D objects located around the well trajectory. (2) We implement a fast multigrid stochastic 1D inversion technique. This inversion strategy enables the estimation of anisotropic formation resistivities, quantifies data misfit, and assesses the uncertainty of inversion results. (3) For the above cases (1a) and (1b), we calculate data misfit for each component of UDAR measurements separately. (4) From data misfit analysis and the associated uncertainty of inversion results for each subset of UDAR measurements, we develop a method to determine the approximate location of 3D objects relative to the well trajectory. (5) Finally, we estimate the spatial location of sandstone injectites in the Grane Field with respect to the well trajectory (see Figs. 1 and 2).

The choice of measurement frequency significantly influences our findings. Low frequencies prove effective for detecting objects situated at a distance and offset from the well trajectory, whereas high frequencies tend to sense objects in close proximity or intersected by the well trajectory. In cases when the 3D object is offset from the well trajectory, reducing the frequency decreases the uncertainty of inversion results or, at the very least, does not significantly increase it. It is essential to emphasize a specific condition: when the 3D object is offset from the well trajectory (e.g., the well trajectory is aligned with the *z* Cartesian axis), the data misfit of the EM measurement component parallel to the well trajectory

(H_{zz}) decreases, while the data misfit for other components (e.g., H_{yy} and H_{xx}) increases. This observation offers valuable insights for the effective real-time detection and appraisal of 3D sandstone injectites located some distance away from the well trajectory.

Look-Ahead-While-Drilling Technology Assessment for Early Hazards Identification in Presalt Offshore Brazil

Antonio Mainieri Vieira da Cunha, Ralf Wilhelm Bohrer, Randolpho Lobo de Freitas Junior, Almir Rogério Pedroso, Geraldo Majela Sartori Brandão, Guilherme Augusto Amaral, Wilson Yoji Nakamura Junior, Fátima Andreia de Freitas Brasil, João Paulo Teixeira da Fonseca, Munir Pinto Koosah, João Antenor Prats Xavier, Caio Eduardo Barbosa Coutinho, Elisângela Cordeiro Pessoa, Eduardo Hilgenberg Mezzomo, Abel da Sila Hermida, and Fábio Pimenta Bernardez, Petrobras; Guillermo Marcelo Cuadros, Ligia de Matos, Charles Silva, Soazig Leveque, and Diogo Salim, SLB

Exploration and development of presalt carbonate reservoirs require the drilling of vertical and low deviation wells. Due to their offset from the bit and shallow depth of detection, conventional logging-while-drilling (LWD) technologies often struggle to predict formation changes ahead of the bit, which could pose a risk during well execution. On the other hand, seismic-while-drilling technologies, offering look-ahead capabilities, may not effectively detect features below seismic resolution.

For over a decade, reservoir-mapping-while-drilling (RMWD) systems, based on ultradeep electromagnetic (EM) measurements combined with inversion algorithms, have been employed in Brazilian offshore operations to assist in geosteering, as well as in geostopping (landing) high deviation and horizontal wells. These systems possess the capability to generate a map of the resistivity profile tens of meters around the borehole in real time. These modular technologies consist of a transmitter placed as close as possible to the bit, along with up to three multifrequency receivers distributed in the bottomhole assembly. However, as the systems were developed for highly deviated wells, a different approach must be implemented in low deviation and verticals to aid geostopping and mitigate drilling hazards.

The objective of this paper is to present the experience in presalt offshore operations in Brazil, using an ultradeep resistivity technology that enables a look ahead of the bit while drilling in vertical or low deviation wells.

This work includes an overview of the drilling risks associated with geological uncertainties, a technical description of this look-ahead system, the planning and interpretation workflows implemented, the application envelope, limitations, the learning curve, and results based on real examples of applications.

A recently developed system enables resistivity look ahead in low deviation wells using the existing ultradeep EM technology hardware. This system utilizes advanced 1D real-time stochastic inversion referenced to the transmitter rather than the midpoint between the receivers. By doing so, it leverages the measurement sensitivity ahead of the transmitter to generate a resistivity map closer to the bit. To enable this capability, an additional step involving the calibration of the receiver-tilted antenna must be performed to enhance detection capabilities ahead of the wellbore. In this new workflow, geological features with sufficient resistivity contrast can be mapped in ahead of the transmitter, allowing for detection ahead of the bit when the contrast enables a greater depth of detection than the transmitter offset.

In extremely high-resistivity environments like the ones encountered while drilling presalt wells, EM measurements penetrate the formation more deeply, allowing for enhanced look-ahead capabilities. Nevertheless, these advantages introduce new challenges linked to formation resistivity uncertainty, as the logging-while-drilling propagation resistivity measurements obtained in the salt section saturate at values significantly lower than the true formation resistivity. Addressing this situation required an adaptation of the look-ahead workflow, in particular for the additional calibration step that relies on formation resistivity as an input.

To date, the operator has utilized the look-ahead system presented in the salt section of three wells. In these instances, it was observed a vertical depth of detection of approximately 30 m ahead of the bit for geological features with strong resistivity contrast. Moreover, it confirmed the system's capability to map complex intervals with multiple conductive layers.

Additional insights gained from this technology implementation include the redefinition of the operating frequencies to be transmitted for each receiver in real time, the assessment of the required amount of stacking needed for noise reduction, and the management of the rate of penetration to minimize interference with the drilling operation.

The addition of the resistivity look-ahead technology to the existing geostopping workflows could play an important role in the management of drilling hazards, particularly as presalt reservoirs become depleted.

Optimizing Well Placement Using Real-Time Ultradeep Resistivity Look-Around Inversion – Deepwater GOM Case Study

Franck Michel, David Lopez, and Do Dang Sa, Halliburton; Christopher Moyer, Amy Borgmeyer, Bobby Bodek, and Alejandra C. Maldonado Pena, Oxy

Deepwater development drilling in the Gulf of Mexico region is evolving to more highly deviated wellbores with complex completion designs. The wellbore placement of such wells can benefit greatly from ultradeep resistivity (UDR) technology for addressing many geological and reservoir challenges. Such solutions integrated with a geosteering service with the capability to perform one-dimensional (1D) and three-dimensional (3D) resistivity inversion modeling as drilling progresses can be critical for the ideal positioning of a development well.

A challenging well to drill, with a highly deviated production section, targeted an area of amplitude consistent with pay sand, broken up by faulting and possible unexpected change in bed thickness. One of the most critical objectives of the well was to place the intermediate section shoe inside the target reservoir sand while minimizing the loss of the vertical section. The reservoir top uncertainty was ±20 ft TVD.

Using synthetic geological resistivity models, several geomapping resistivity inversion modeling scenarios were performed prewell as part of a detailed feasibility study. This allowed fit-for-purpose UDR technology selection and deployment for this project. The solution was to use a UDR technology with real-time 1D resistivity look-around inversion.

The UDR geomapping was used to identify the top of the reservoir while drilling and land inside the targeted sweet spot. The service was also planned to be used in real time in the subsequent section to assist in the mapping of the reservoir thickness, giving the operator a detailed understanding of their asset.

The landing hole section was drilled using a push-the-bit rotary steerable drilling system, UDR, and logging-while-drilling (LWD) penta-combo bottomhole assembly (BHA). This advanced BHA drilled 2,208 ft MD, landing at 75° inclination in the sweet spot of the reservoir. While dogleg severity was minimized to less than 4° per 100 ft, UDR reached over 40 ft TVD look-around measurements for a successful soft landing. Using the real-time UDR look-around 1D inversion, the top signature of the reservoir was identified ~42 ft TVD below the LWD UDR tool transmitter. The top of the reservoir was confirmed to be ~38 ft TVD below the tool position, with the bit ~20ft TVD above the reservoir top. Once the well was landed in the reservoir, the 1D inversion mapped the reservoir thickness as 105 ft. The apparent formation dip was confirmed ~12° downwards in the drilling direction with local variations. The bit was projected to be ~49 ft TVD below the reservoir top. The successful geomapping service delivery was complemented by acquiring representative formation pressure using LWD for reservoir understanding. Following the well delivery, the daily production numbers showed higher results than expected.

This case study provides detailed information on an advanced UDR geosteering service as a new technology for the US Gulf of Mexico deepwater area. It demonstrates the potential and capability of the service for future deployment in the area with applications such as reducing geological uncertainties while drilling in complex turbidite trap reservoirs to maximize reservoir contact.

Predicting the Future With UDAR 3D Resistivity Modeling – A New Key to Unlock Multidimensional Reservoir Steering

Yazil Abbas, Mauro Viandante, Jianguo Liu, and Mikhail Zaslavsky, SLB; Per Erik Wærum, Sven Severin Gundersen, Øystein Spinnangr, and Abraham Wayne, Repsol Norge AS

In the realms of geosteering and reservoir mapping, predrill simulations/feasibility studies are performed mainly for three reasons: (a) confirm the applicability/viability of deploying an ultradeep azimuthal resistivity mapping (UDAR) tool in in a range of predicted resistivity contrasts and to evaluate the detection/sensitivity of the UDAR multidimensional inversions to address the objectives for the subject well, (b) confirm the optimal number of UDAR receivers and the optimal spacing between the transmitter and each receiver, and (c) confirm the optimal frequencies for each UDAR transmitter-receiver pair. For reservoir-mapping-while-drilling systems which focus on geosteering in TVD only, the workflow to perform feasibility study has matured over the last few years, but for multidimensional reservoir mapping systems, the usefulness of a UDAR feasibility study is very much dependent on having a comprehensive three-dimensional (3D) geological model that captures structural and resistivity information around the planned well. The challenge with current industry standard geological models is that the grid sizes are much larger than commonly deployed UDAR depth of detection (DOD), thus undersampling the boundary detection. Another challenge in performing a multidimensional UDAR feasibility study is the forward modeling ability that can simulate downhole raw measurements capturing all the 3D elements of the formation (dip, azimuth, resistivity anisotropy).

Multidimensional UDAR feasibility has its roots in the contributing factors such as geophysical data, the grid size of geological models, and the robustness of the forward modeling algorithm. The geological and geophysical data are usually provided by the operators, and this information is further refined to be able to be used in the feasibility work. The most important step in this work is the grid refinement (x,y) to a meaningful value that is less than the DOD of the planned UDAR configuration while preserving the vertical resolution (z). The grid refinement can either be local (around the wellbore) or regional. If the grid is refined from an already-built coarse grid, there is a good chance that structural details on the scale of UDAR's DOD are not captured. The structural model workflow presented in this paper was built from the base using a corner-point gridding method on a 5 × 5 m (x,y) scale with seismic interpretation data (fault model, seismic horizons) as the primary input. Petrophysical modeling was then performed on the high-resolution structural grid, specifically focusing on resistivity data from the nearby offset wells.

Finally, a standard property modeling workflow was executed involving upscaling of well logs, data analysis (data transformations, declustering, variograms), and petrophysical modeling (both Gaussian-simulation- and Kriging-based). The resulting 3D resistivity model generated is used as an input to the UDAR multidimensional forward modeling process that uses the two-dimensional (2D) finite difference method, simulating all 3D electromagnetic (EM) components simultaneously under the given set of conditions: a formation model, a trajectory, and the UDAR sensor structure. This theoretical log response (simulated) is then input to multidimensional UDAR inversions, which form the basis of this feasibility work.

The multidimensional UDAR feasibility work shared in this paper gives insight into the 3D resistivity modeling workflow and how it can be used in the well-planning stages. In real time, the UDAR results were observed to be similar to predrill simulations, which helped in a smooth execution of azimuthal geosteering strategy and drilling risks' mitigation. The differences between simulated and real-time UDAR inversion are mainly because of predrill uncertainties with regard to geological structure; nevertheless, predrill multidimensional UDAR simulations represent a good reference for well planning and for foreseeing critical geosteering decisions along the planned well path.

Proactive Geosteering With New Multilayer Mapping Technology for Optimal Well Placement on the Edges of Mature Fields

Agustin Paladines, Camilo Tellez, Israel Campos, Alex Iza, Pablo Cisneros, Valeria Lucas, Vinicio Mena, Paul Cornejo, Andres Fonseca, Sergio Mata, Gustavo Núñez, José Rodas, Patricio Zamora, SHAYA; Egor Kovarskiy, Alexey Cheprasov, Igor Hernandez, Guillermo Cuadros, Manuel Garcia, SLB

The main objective of this study is to demonstrate examples of the use of a new multilayer mapping-while-drilling technology for mature field development to optimize the placement and completion of horizontal wells directed towards the flanks of the field with poor stratigraphic control, abrupt lateral changes, and high risk of the aquifer presence. Additionally, the paper shows the contribution of the data acquired by this technology to provide a deep understanding of reservoir geology and the precise calculation of well productivity.

Geological uncertainties and operational risks are factors that can jeopardize a horizontal drilling campaign if not managed properly. This is true even for mature fields when the need for further development pushes drilling toward the flanks of the field structure. However, the success rate of such wells can be greatly improved with the usage of modern multilayer mapping-while-drilling technologies. The Ecuadorian oil fields are composed mostly of two main reservoirs, Napo: Lower U and Lower T. Regularly, these reservoirs are made of three sand bodies which are characterized by abrupt lateral changes of facies and rock properties due to its estuarine nature, even leading to a complete pinchout of the sand bodies. The latest horizontal prospects are placed and navigated in the flanks of the fields with the aim of optimizing production; however, those areas present a higher geological uncertainty for horizontal drilling than the center of the structure, where better rock quality is found. Hence, such peripherical wells cause fewer errors during geosteering. One of the limitations associated with the legacy bed-boundary mapping technologies is linked to their poor capabilities to detect multiple thin, unproductive layers, which, if overlooked, can result in a considerable loss in net pay. The new multilayer mapping while drilling, which makes use of deeper resistivity measurements and new deep azimuthal measurements, has been implemented in a block of the Ecuadorian Oriente Basin. This system, supported by a new deterministic inversion engine, improves the understanding of the geology drilled by providing a finer resistivity map around the borehole in real time, leading to more proactive geosteering decisions.

Important results have been achieved with the implementation of the new mapping-while-drilling technology. First, the received data allowed a better understanding of the formation structure, petrophysical properties, and sand connectivity. With this information, the geological model was precisely updated around the borehole. Second, during drilling guided by the multilayer inversion, pinchouts upwards were detected. Thus, geologists could better understand lateral facies changes and react correctly to continue with drilling towards another sand body. Third, all decisions were made on time and allowed to avoid drilling inside of nonproductive intervals, to confirm that there is no more reservoir, and to detect on time the position of the lower sand body to place the well inside of the sand anomaly detected by geosteering. In addition, this technology opens new prospects for horizontal drilling in the block, and this experience can be extrapolated to other fields with similar geological scenarios in the Ecuadorian Oriente Basin.

Production Sustainability of a Challenging Heterogeneous, Mature Carbonate Reservoir: An Integrated Solution Comprising Near- and Far-Field LWD Measurements

Amr Serry, Shafiq Ahmed, and Sharifa Yousif, ADNOC; Sanathoi Potshangbam, Nada Al Sayed, and Asim Mumtaz, Baker Hughes

Sustaining optimal production from a well not only requires maximum reservoir exposure as a smooth profile but also a better understanding of the reservoir architecture and fluid distribution in 3D space. This case study represents an integrated approach to drilling a complex reservoir, offshore Abu Dhabi, which is heterogeneous, fractured, and complexly faulted. These common geological features can lead to water slumping and conning in some cases. The ultimate objective was to boost the dry oil production from the

upper and lower drains of the subject well. This required proactive well placement to maximize the reservoir exposure in real time while drilling and simultaneously characterize the reservoir further away from the wellbore in both drains. Moreover, the acquired data enabled optimization of the completion design, post-drilling, to balance the contribution from the different well compartments and prolong the well life.

Integration of the near- and far-field logging-while-drilling (LWD) measurements was considered for this application. The continuous mapping of the surrounding resistivity profile and defining the reservoir properties was possible by utilizing a tool with a larger depth of detection, integrated into a conventional triple-combo bottomhole assembly. The selected extra-deep azimuthal resistivity tool operates at lower frequencies and has a flexible spacing setup between its transmitter and receiver sections, which helps to achieve a greater depth of detection. This capability was the primary selection consideration in order to be able to obtain water saturation and detect the surrounding bed boundaries away from the wellbores. Mapping the change in resistivity above and below the well path helped in making informed well placement decisions and efficiently navigating along the optimum reservoir zone.

Utilizing the extra-deep azimuthal resistivity improved the understanding of the geological setting around the well area. The application has been proven highly accurate to place the drains in the optimum reservoir targets. It mapped the water slumping intervals from the above unit and also the change in water level approaching from below the well trajectory. In the upper drain, an increase in water saturation from top and bottom was mapped, based on which TD was called earlier than planned. Near-wellbore data acquired for reservoir characterization were integrated with the far-field high-water saturation maps. This served as decisive information for the completion design optimization to minimize the potential risk of an early water cut.

This case study elaborates on the successful deployment of the extra-deep resistivity measurements in an integrated approach to mitigate the complex reservoir challenges and potentially increase its productivity.

The Integration of Shallow to Ultradeep LWD Data: The Key to Geosteering and Improved Reservoir Understanding

Carlos Sarquez and Rosamary Ameneiro, Halliburton; Petter Vikhamar and Embla Galdal, Conoco Phillips; Nigel Clegg, Halliburton

Reservoir insight is driven by the integration of different types of data, depending on its nature, its scale, and the way that it is acquired and presented. Using this insight to understand the transitions and distributions of lithology and fluids along a wellbore trajectory is critical for optimal well placement and configuration of the completion string. Resolving the reservoir architecture using multiple logging-while-drilling (LWD) tools and real-time inversion of electromagnetic data is a decisive factor in narrowing the uncertainty and enhancing the geological characterization of the areas around the well path.

In terms of reservoir scale, different LWD tools bring different advantages to providing reservoir insight. LWD density images provide a detailed view of lithological dip angles (internal sedimentary structures, stratification, and structural elements) in the near-wellbore environment, whereas deep electromagnetic (EM) LWD inversions allow mapping resistivity distribution much further into the formation, up to 20 to 30 ft from the wellbore. Both tools provide useful definitions of features within the reservoir but at different scales. They are both mutually supportive, providing high confidence in geological models representing the reservoir and providing unique information, increasing the understanding of the reservoir. Azimuthal resistivity images act as a link between these two scales; however, the integration of these responses is still closer to the small-scale side of the range. When an ultradeep EM tool is run in combination with the deep EM and density tools, reservoir insight is revealed into the region of 100 ft from the wellbore. Some detail is lost due to the larger volume under investigation, but linking the information from all three tools provides reservoir understanding from the highly detailed near-wellbore data through to the lower resolution but deeper understanding distant from the well.

In a massive carbonate reservoir, a series of intercalated layers were evident on the real-time azimuthal density and resistivity images, indicating that the reservoir is more complex than a single massive unit. Deep EM LWD inversions showed a thicker resistive zone with internal weak resistivity transitions. The shallow resistivity EM LWD inversion resolves what was interpreted as a kink folding series highlighted by the definition of a less resistive layer. In addition, the dips picked from the density image confirm the dipping trend at each flank of every fold, revealing the direct correlation between the subseismic structure and its effect on the resistivity distribution. The ultradeep inversion results put these smaller-scale features in the context of the entire target formation, providing the large-scale picture.

Different scale data integration contributes to a deeper understanding of the reservoir architecture and its relation to the reservoir lithology and fluid distribution. This leads to enhanced wellbore positioning in the reservoir by reducing the decision-making uncertainty and improving reservoir understanding.

Uncertainty Estimation for Ultradeep Azimuthal Resistivity Measurements Using Machine Learning

Pontus Loviken, Hui Xie, Gordana Draskovic, Nguyen Thanh Nhan, Keli Sun, and Kent Harms, SLB

Geosteering and reservoir mapping electromagnetic tools provide complex deep and/or ultradeep azimuthal resistivity (UDAR) measurements while drilling. Using interpretation software, these measurements can be used to profile formation structure and reservoir fluid distribution more than 100 ft away from a wellbore. The quality of this interpretation is highly dependent on the quality of the raw measurements. It is often necessary to distinguish measurements based on their noise level to avoid biasing or even deteriorating the interpreted results with unreliable data.

Because acquiring and processing UDAR measurements themselves are already a challenging task, measurement uncertainty has never been systematically investigated. Until now, the standard approach to undertaking the problem has been for geosteering engineers to use their experience to manually remove channels expected to be less reliable. One potential resource would be UDAR noise models, which could be used to simulate tool responses based on a given formation; however, knowledge about the true formation can only be obtained after the interpretation process.

This paper presents a different approach for evaluating the quality of UDAR measurements by training a machine-learning (ML) algorithm to estimate channel noise levels directly from the raw measurements, thus avoiding the need for an initial interpretation. To this end, a large data set is created with raw measurements and noise levels from a wide range of simulated scenarios. An ML algorithm, e.g., a neural network or a decision forest, can then be trained to predict these noise levels directly from the measurements without access to the actual scenario. The trained model can then be used to evaluate the noise levels in unseen scenarios and, ideally, real-world cases.

As proof of concept, the proposed method has been applied to the noise model of a UDAR tool with 96 channels, consisting of eight types of measurements with six frequencies and two receivers. Scenarios were generated using a formation distribution designed to cover most cases that would be encountered in reality, and noise levels were computed as the standard deviation of output for each channel. The training set had 100,000 samples, and the test set had 10,000 samples. The final performance was computed using the relative error, with an error goal of less than 10% for at least 90% of all the data in the test set. Among all of the approaches, the authors found feedforward neural networks perform the best, particularly when predicting all the channels in parallel. It seems like attempting to predict noise in one channel might help bootstrap the feature search for other channels as well. With four hidden layers, we were able to reach the 10% target for 42 of the 96 channels, in particular, the low-frequency cases. The worst-performing channel achieved a relative error of 20.6% for the best 90% of its data. Classifying neural networks focused on one channel at a time were found to improve this result, but still not to the point where the 10% goal was obtained. As an additional test, the trained network was used to provide predictions on simulations of actual scenarios and benchmark problems, in which the method performed very well. As shown in the figure, the predicted uncertainty (blue dash lines) matches very well with the uncertainty computed directly from the noise model (red lines) in the final real-world scenario tests.

Use of Multilayer Mapping-While-Drilling Technology for Field Exploration Strategy Optimization While Increasing Production

Oscar Navarro, Anthony Stuart, William Cage, Alan Santos, Juan Cárdenas, Daniel Lancheros, and Andrés Rocha, Hupecol; Egor Kovarskiy, Igor Hernandez, Guillermo Cuadros, Alexey Cheprasov, Santiago Piedra, Adriana Paulin, and Eslendy Lara, SLB

Although the Llanos area in Colombia is well-studied, and principal formations are known and mapped, there are still many challenges in the exploration and development of new areas. These challenges arise from the high heterogeneity of the oil-bearing formations and the limited amount of often low-quality seismic data available. This is especially true for small operators that have limited budgets and struggle to justify the implementation of advanced technologies, such as ultradeep-azimuthal resistivity (UDAR) systems for horizontal drilling. The objective of this paper is to demonstrate the strategy for field structure mapping and exploration through horizontal drilling with multilayer mapping-while-drilling technology while increasing production and optimizing completion.

Initially, horizontal well placement was not part of the field development in the area. The plan consisted of drilling and completing only vertical and deviated wells. Based on low-quality 2D seismic data and two pilot holes, which have shown the presence of ~20 to 30 ft TVD heterogenous oil-bearing sand pocket, two deviated wells in opposite directions were drilled, but the results were not satisfactory. One of these wells did not detect the target sand, and the other did, but production did not achieve the necessary level. It was clear that the structure is highly uncertain, and the target zone is heterogeneous, varying in thickness. Based on this and the successful development of nearby areas through horizontal drilling by other operators, it was decided to change the strategy. The goal was to map the structure and increase production using geosteering mapping technology capable of steering in thin heterogeneous targets with possible resistivity above 1,000 Ω·m, while having enough depth of detection (DOD) to map as much volume as possible around and address any possible sudden changes in target geometry behavior. Additionally, to minimize the number of exploration horizontal wells, a particular approach in well trajectory planning was implemented.

As part of the new strategy, the first horizontal well was drilled in the direction of the successful deviated well to map the structure in that direction and evaluate potential production increase. The results were a breakthrough. The high-resolution inversion from the new multilayer mapping-while-drilling technology showed that the target zone, in fact, consists of several noncontinuous channels with thickness variation from 4 ft up to 15 ft, separated by nonproductive seals. Additionally, the new well placement technology allowed us to achieve the necessary increase in net pay. Following this success, two more horizontal wells, oriented in opposite directions perpendicular to the first one, were drilled. Integrated analysis of the inversions from these three horizontal wells allowed defining the optimal direction for the future horizontal wells, mapping part of the area with no reserves, and showed the existence of various parallel productive channels. Overall, the selected strategy demonstrated that no UDAR multilayer mapping-while-drilling technology could be used successfully for structural mapping in the case of heterogenous low-thickness formation.

IMAGING TECHNOLOGY AND APPLICATIONS – BEYOND DIPS

A Job Planner Software for Oil-Based Mud Resistivity Imagers

Ahmed Fouda, Baris Guner, and Peter Barrett, Halliburton

Design and interpretation of oil-based mud resistivity imagers are significantly more difficult than their water-based mud counterparts. The presence of resistive oil-based mud reduces the sensitivity to the formation and necessitates the use of higher operating frequencies. However, at these higher frequencies, formation permittivity starts to affect the obtained images, with the amount of contribution from the formation permittivity being dependent on the exact frequency that was employed. Due to these complicated factors affecting tool performance, optimal operating conditions for the tool vary based on the specific running environment as well. Thus, a job planning workflow and associated software for a next-generation oil-based mud resistivity imager tool has been created with the intent of helping users optimize the tool parameters for the needs of the given logging job.

At the core of the job planner is a forward model that can simulate the tool response for different realistic formation geologies. The forward model has been calibrated using an experimental database that was obtained with a purpose-built measurement fixture. Measurements were made for a range of formation and borehole properties in this fixture. Tool responses for different representative formation resistivity, formation permittivity, standoff, dispersion, and dielectric loss values, as well as muds with different compositions (e.g., different oil-to-water ratio values), have been obtained. A random media generator that allows the users to create a realistic representative downhole environment has been implemented. Job planning software allows the users to adjust the size and properties of the formation features and layers. The rugosity of the borehole may also be adjusted through the software. Effects of job parameters such as operating frequency, pad pressure, logging speed, pad-borehole curvature mismatch, and measurement noise on the image quality are visualized through the job planner. Empirical relationships have been devised to relate the variation of the job parameters to image resolution and noise level.

Users interact with the software through a graphical user interface (GUI) to modify the aforementioned job parameters. Thus, they are able to create a representative environment for an upcoming job and predict the tool performance. By adjusting the job parameters and visualizing the effects, users can optimize the tool response for a specific well. A quantitative estimation algorithm has also been integrated with the job planner. This allows the estimated formation and borehole properties to be compared against ground truth values and, thus, a numerical metric for the performance of the tool to be defined. This metric is, in turn, used to guide the optimization of the job parameters.

Assessing the Impact of Image Data on Enhancing Rock Typing and Formation Evaluation
Pallavi Sahu and Zoya Heidari, The University of Texas at Austin

Reliable rock classification is important for estimating petrophysical properties and making informed production decisions. High-resolution image data (e.g., image logs, core photos, and CT-scan images) can enhance rock classification by incorporating rock fabric (i.e., spatial variation of rock components) information. The additional value that image data contributes to enhancing formation evaluation is essential to assess for making informed decisions on acquiring expensive image data. Recently developed methods have been proven successful for image-based rock classification, mainly in siliciclastic formations. However, the reliability of image-based rock classifications in heterogeneous carbonate formations comprising complex depositional sequences has yet to be investigated. The objectives of this paper are (a) extracting rock textural features to obtain image-based rock classes from high-resolution images that capture changes in depositional sequences of complex carbonate formations, (b) assessing the impact of different sources of image data and their integration on the enhancement of rock classification, and (c) evaluating the reliability of rock classes identified by integrating well logs and image data and its impact on formation evaluation.

First, we conduct conventional well-log interpretation and preprocess the image data (i.e., CT-scan images, core photos, and image logs) using the image masking techniques to remove artifacts and noise from the available images. Then, we extract textural features from wellbore/core image data using a gray-level co-occurrence matrix (GLCM) algorithm that captures the spatial relationship of pixel intensity values in images to quantify rock fabric. Next, we adopt an unsupervised algorithm to detect rock classes using the extracted features. We automatically optimize the number of rock classes by minimizing a cost function defined based on rock-type estimates of permeability. We perform and compare rock classification through three different methods taking as inputs: (a) only conventional well logs, (b) different sources of image data (i.e., image logs, core photos, and CT-scan images) and their integration, and (c) the integration of conventional well logs and image data. Finally, we compare the outcomes of these three methods and their impact on the assessment of petrophysical properties.

We applied the proposed workflow on image data (i.e., CT-scan images, core photos, and image logs) and well logs in a presalt carbonate formation having a complex syn-depositional rock texture and pore system altered by a diagenetic process. The integration of image-based features and well logs decreased the mean relative error in estimates of petrophysical properties by approximately 30%. The rock classes obtained by CT-scan images were more successful in enhancing petrophysical property estimates than rock classification using other sources of image or well-log data. The contribution of image data was more measurable in rock types with higher levels of heterogeneity and spatial variation of rock fabric. The outcomes of this work are (a) to capture changes in depositional sequences of heterogeneous carbonate formations in rock classification, (b) to assess the impact of different sources of image data (i.e., CT-scan images, core photos, and image logs) on rock classification efforts of complex carbonate formations, and (c) to enable taking decisions on the optimum type of image(s) for image-based rock classification that best captures rock fabric information in a given formation.

Assessment of Petrophysical Heterogeneity Based on Image Data
Pallavi Sahu and Zoya Heidari, The University of Texas at Austin

Formation heterogeneity that broadly defines the spatial variations in rock properties has long been recognized as an important factor for the reliable assessment of petrophysical properties and their variation in subsurface rocks. Conventional methods to quantify formation heterogeneity depend on visual inspection of core samples or statistically derived well-log-based coefficients. These coefficients represent heterogeneity in a data set by a single value and overlook discontinuity in petrophysical properties. To fully understand the depth-by-depth variability in petrophysical properties, it is important to quantify the spatial variability of rock composition and texture. The interpretation of heterogeneity also varies with the scale of investigation. High-resolution images such as CT-scan images, core photos, and image logs can potentially be instrumental in assessing heterogeneity while honoring rapid variations in rock fabric (i.e., the spatial distribution of rock and fluid components) in multiple scales. However, reliable and fast methods for integration of the aforementioned sources of image data to quantify depth-by-depth heterogeneity have yet to be developed. The objectives of this project are (a) extracting image-based features at different scales of investigation that capture the spatial distribution of rock components, (b) quantifying the impacts of data scale and resolution on the estimated rock fabric features, and (c) developing a new method to quantify depth-by-depth heterogeneity by integrating core and CT-scan images as well as conventional well logs.

First, we preprocess high-resolution core and CT-scan images using the image masking technique to remove artifacts from the images. Then, we use a gray-level co-occurrence matrix (GLCM) algorithm that captures the spatial relationship of pixel intensity values in images to quantify rock fabric. We compute GLCMs in rectangular sliding windows having the same horizontal dimension (image width) and varying vertical dimensions to extract rock textural features at multiple scales. To capture depth-by-depth variability in rock fabric by a unique value, we employ principal component analysis (PCA) on extracted textural features and compute depth-by-depth rock textural characteristic values (RTCVs). RTCVs capture the maximum spatial variance within extracted rock textural features. Subsequently, we develop an analytical model using the computed RTCVs to assess depth-by-depth petrophysical heterogeneity. Finally, we normalize petrophysical heterogeneity to define the depth-by-depth heterogeneity index (HI).

We successfully applied the proposed method to synthetic image data and a field data set from a well drilled in a siliciclastic sedimentary environment. Results demonstrated that variations in extracted textural features capture variations in rock composition and petrophysical properties. This enabled the comparison of the degree of heterogeneity associated with different scales of investigation within the formation. The proposed workflow honored the impact of data scale and resolution in assessing heterogeneity by incorporating rock textural features extracted at different scales. The introduced HI quantified depth-by-depth local heterogeneity within evaluated depth intervals and enabled the classification of rock types based on heterogeneity in rock texture and petrophysical properties. HI facilitated selecting the optimum number and location of core sampling by identifying depth intervals having local geological complexities. The novelties of this workflow include taking into account quantitative rock fabric information to quantify depth-by-depth heterogeneity and reducing the uncertainty in quantifying formation heterogeneity by incorporating the impact of scale. The introduced HI is an efficient tool for making real-time decisions for representative core sampling to enhance core-scale and well-log-scale petrophysical models.

High-Definition Acoustic and Resistivity Imaging-While-Drilling Technologies: Experiences in the Brazilian Presalt Carbonate Reservoirs

Ana Patricia Cavalcanti de Castro Laier, Antonio Persio Silvestre, Erica Kato Pacheco Ferraz, Pamella Paiva Fernandes, and Anabela Porto Rosa, Petrobras; Guillermo Marcelo Cuadros and Andre Esteves, SLB

Characterizing geological features and artifacts of interest for geological, geomechanical, and petrophysical analysis is vital in the presalt reservoirs. For years, a significant technology gap between wireline and LWD systems has centered around borehole imaging resolution. The lack of high-definition borehole imagers has deterred companies operating offshore in Brazil from transitioning to full LWD acquisition. Nevertheless, the utilization of the new imaging systems outlined in this study effectively bridges this technological gap.

The aim of this study is to share our experience with the application of advanced high-definition borehole imaging logging-while-drilling (LWD) technologies in five wells drilled in the presalt carbonate reservoirs in offshore Brazil.

This manuscript encompasses several key aspects, including the newly implemented borehole imaging technologies, the operational hurdles encountered in optimizing image acquisition from floating rigs, and lessons learned obtained since it was implemented in 2021.

In Petrobras Brazil offshore operations, two types of LWD borehole imaging technologies were introduced.

The first one is a dual-physics system that provides high-resolution acoustic images in all mud types, as well as apparent images in oil-based mud. This borehole imager acquires high-definition acoustic images through four independent sensors, operating simultaneously at low and high frequencies, resulting in 16 amplitude and transit time images, along with borehole radius measurements, and offering a resolution equivalent to the one from wireline technologies employing the same pulse-echo principle.

The second technology is a laterolog-type system designed for water-based mud that provides qualitative images and resistivity measurements at different depths of investigations. It incorporates toroidal antennas, button electrodes, and an imaging sleeve with an array of eight button electrodes measuring 0.4 in. Moreover, this button array design facilitates full borehole imaging at high rates of penetration due to measurement redundancy.

Acquiring high-resolution borehole images on floating rigs presents a substantial challenge. Although the image resolution of these systems is smaller than 1 cm, the depth reference can oscillate vertically over more than 100 times that value due to residual rig heave. Consequently, specialized processing techniques were implemented to mitigate its impact on the images.

Advanced high-definition LWD borehole imaging technologies deliver high-quality acoustic and resistivity images. In combination with other LWD or wireline measurements, they can be used for intelligent completion design and to enable integrated geological, geomechanical, and petrophysical analysis. The lessons learned to date after implementation in distinct presalt carbonate fields have proven invaluable for refining operational parameters and conditions essential for improving image log acquisition in offshore drilling environments.

This experience results in a more efficient usage of rig time with the consequent CO_2 emissions reduction, cost optimization, and operational risk minimization when compared to conventional logging.

The knowledge and experiences shared here hold the potential to be applied to other fields and reservoirs with analogous requirements.

Image Data: The Unexplored Potential for Reservoir Characterization, Brazilian Presalt
Gilberto Raitz Junior, Théo Farhat, Jeferson Santos, and Carolina Ribeiro, Laboratory of Sedimentary Geology (Lagesed)

The Brazilian presalt carbonate reservoirs, known for their vast hydrocarbon reserves, present unique challenges due to their inherent complexity. Characterizing these reservoirs effectively is essential for exploitation. However, traditional methodologies that use the thin section for description (petrographer) and samples of plugs or sidewalls for petrophysical analysis (petrophysicist) are necessary to describe and characterize the reservoir but require a lot of time and effort to be completed. With the technologies we can build today, the image data can be used to obtain results quickly. Still, it is not intended to replace but rather to complement analysis to understand better the reservoir in the time without rock or petrophysical data. That way, while the oil and gas industry has leaned heavily on seismic and well-log data, image data (thin sections) remains a vast, underutilized resource.

This study delves into the untapped potential of image data, investigating its capabilities to revolutionize reservoir characterization in the Brazilian presalt with the simulated petrophysical data and apply it to rock-type analysis. A data set composing high-resolution thin-section images (100 samples) from a selected presalt well (9-BRSA-928-SPS) was created in Sapinhoá Field to explore the potential of image data. Advanced image processing algorithms were employed to analyze the collected data (DeePore), focusing on delineating porosity types, absolute permeability, formation factor, cementation factor, pore density, tortuosity, coordination number, throat radius, pore radius, throat length, pore to the throat aspect ratio, specific surface, pore sphericity, grain sphericity, average grain radius, and relative young module. Moreover, this study used deep-learning models, particularly convolutional neural networks (CNNs), which were trained on a data set consisting of 1,418 images. The analysis of 100 thin sections in the data set was performed using a pretrained algorithm. The aim was to classify the different classes of rock types, estimate petrophysical properties, and characterize reservoirs to understand diagenetic alterations or geological characteristics. These automated predictions were then integrated with traditional reservoir data (well-log data, well core data, and routine core analysis) to understand the reservoir better.

The integration of image data into the reservoir characterization workflow yielded results that can be classified as four groups of rock type correlated by flow units. Firstly, the pore-throat properties and Leveret J function of data obtained from images are better than traditional methods because they do not destroy the sample and obtain reliable data for classification in different rock types, offering details of the rock matrix and fluid flow. Moreover, the image data provided crucial insights into zones that underwent diagenetic alterations (cementation, dissolution, silicification, and dolomitization), often missed by conventional methodologies or are more difficult to obtain. These zones are pivotal as they influence fluid flow and reservoir quality. Two primary observations emerged from this study: the power of image data in capturing reservoir heterogeneity and the efficiency of machine learning in processing vast data sets rapidly. In conclusion, image data hold transformative potential for reservoir characterization in the Brazilian presalt. By harnessing advanced imaging techniques and coupling them with machine-learning algorithms, the industry can achieve a quicker, more valid, and more efficient time characterization process. This approach promises to streamline reservoir management strategies and paves the way for novel interdisciplinary research, bridging geosciences with digital technologies.

Integrated Application of Advanced Logging While Drilling for Understanding Altered Basement Rocks: A Case Study From the Norwegian North Sea
Sayyid Ahmad, Halliburton; Lars Riber, AkerBP and University of Oslo; Ingrid Piene Gianotten, Sanaz Javid, and Ophelie Durand, AkerBP; Srimantha Chakraborty, Karol Riofrio Rodriguez, Marius

Lundegaard, Gianbattista Tosi, Robert Gales, and Richard Michael Holland, Halliburton; Knut Richard Straith and Nils Andre Aarseth, AkerBP; Sami Eyuboglu, Halliburton

Altered basement rocks have been identified as part of petroleum reservoirs in some Norwegian North Sea oil fields. The challenges when targeting altered basement rocks during drilling are the high degree of variation over short distances, uncertainty related to productivity, and reservoir quality. Extensive outcrop and well studies, integrated with core and other available log data, show that these basement facies can be subdivided into specific categories controlled by fractures and the degree of physio-chemical alteration. Recently, an infill campaign was executed in Field A, where a horizontal well targeted these altered basement rocks, in addition to some conglomerates. The objective of this case study is to present an integrated workflow using real-time advanced logging-while-drilling (LWD) data and surface measurement interpretations to understand the basement facies architecture. This approach has the potential to facilitate wellbore placement decisions and optimize completion design within these physio-chemically altered intervals.

This study utilizes the following advanced sets of LWD logs: (1) high-resolution ultrasonic impedance and time-lapse caliper images, (2) ultradeep azimuthal resistivity inversions (UDAR), (3) nuclear magnetic resonance (NMR) logs, (4) formation pressure measurements, (5) X-ray fluorescence (XRF) analysis performed on drill cuttings, and (6) other conventional log data. The integrated approach consists of two main steps for data integration and data interpretation: (1) real-time integrated interpretation while drilling and (2) quick turn-around interpretation during bit trips using memory data. During the real-time interpretation, conventional log data, mud gas readings, deep resistivity inversion, formation pressure measurements, and NMR and XRF data were used to identify the different reservoir intervals and to perform the first-pass formation evaluation interpretation. During the second stage of interpretation, high-resolution images from tool memory were integrated to provide textural facies characterization.

With the real-time integrated interpretation approach, it was possible to map conglomerates and basement intervals using UDAR and conventional log data. In this phase, XRF elemental crossplots (total alkali silica (TAS) diagram for igneous rocks based on the relationship between SiO_2 vs. Na_2O + K_2O) were also integrated to identify basement intervals with various chemical compositions. As a result, three main basement units were observed: Unit 1, with very high resistivity, interpreted as a dioritic basement from the TAS diagram and conventional log measurements, Unit 2, with medium resistivity and lateral sharp changes in resistivity, interpreted as granodioritic by using TAS diagram and conventional log measurements, and Unit 3, with medium to high UDAR resistivity, and with lateral sharp changes in resistivity, interpreted as granitic by using TAS diagram and conventional log measurements. By integrating detailed ultrasonic image interpretation and NMR data, the basement was further subdivided into different specific image facies types. The dioritic basement was described with three different image textures, fractures of differing type, intensity, and qualitative width, and multimodal NMR T_1 distributions. Only within this interval were cemented low, high-angle, and higher acoustic impedance mineral-filled veins interpreted. During formation pressure testing, low mobility was observed within this zone. Granodioritic basement could be described with four different image textures, differing types, intensity, and qualitative width of fractures with bimodal or multimodal NMR T_1 distributions. The overall quality of formation pressure measurements was better than Zone 1, but calculated mobility was still low. The granitic basement was also dominated by different image textures. As a result, a comprehensive approach of data gathering and integrated interpretation in real time helped to design suitable completions and placement of packers and screens with good confidence. This integrated approach with detailed image facies interpretations helped to define facies architecture for the altered basement, which will be incorporated in future reservoir property modeling for further development of the area.

Optimizing Petrophysical and Geological Evaluation on Tight Oil Reservoir in a Braided Delta Fault-Nose Structure, Pearl River Mouth Basin, Offshore South China
Bo Liu, Huanling Bian, and Chenglong Wang, Baker Hughes; Lipeng He and Jian Li, CNOOC Shenzhen Ltd.

The Lufeng14-4 structure is a fault-nose structure in the Pearl River Mouth Basin offshore South China. The tight oil layer is developed at the Paleogene with a braided delta front channel environment, which is featured by low porosity, low permeability, and unclear fracture development. Three appraisal wells drilled in three sub-fault blocks show poor well correlation and different oil-water contact even though the distance among wells is less than 2 km. The electricity resistivity image log of two appraisal wells shows variable fracture orientation and unclear fracture effectiveness. A vague understanding of the tight oil reservoir distribution, connectivity, fracture effectiveness, and possible structural variation leads to oilfield development delays for more than 1 year. Optimized geological and petrophysical evaluation is crucial for effective field development.

To characterize the tight oil formation, logging-while-drilling (LWD) logging suites were deployed. LWD ultrasonic imaging logs were utilized for fracture analysis and geological evaluation, including formation structural variation and sandbody orientation. Open and closed fractures are clearly identified, and open fractures were further divided into vuggy open fractures, fully open fractures, and partially open fractures based on the amplitude and transit time from LWD ultrasonic image logs. Closed fractures were further divided into clay-filled fractures and quartz or calcite-cemented fractures. In addition, LWD Stoneley and shear slowness were utilized for permeability indication and TI anisotropy analysis. The modeled Stoneley slowness (DTST0) from shear is compared with measured Stoneley slowness (DTST) for permeable zone indicator, and the difference between horizontal and vertical shear slowness is correlated with bedding development from image log for anisotropy analysis.

The results show that mid-high-angle partial open fractures are commonly developed in tight sand zonation, and low-mid-angle vuggy open fractures are mainly developed in shale interlayer. Open and high-angle fractures may communicate among different tight zonations and increase the vertical connectivity of different reservoirs. Steeper formation dips and syn-formation microfaults are identified from the image log and fully demonstrate the reservoir uplift during horizontal well landing. The reservoir is isotropic when the two shears' slowness (horizontal and vertical) overlap, and the LWD ultrasonic image log shows no beddings, and when the reservoir is anisotropic, the two shears' slowness differs, and LWD ultrasonic image log shows beddings. Three microfault zones were identified by LWD ultrasonic image log, and one is considered permeable by Stoneley analysis. The DST for the first development well has an oil production of 100 m^3/day with no water.

The successful development of Lufeng14-4 tight oil by advanced LWD logging suites is a remarkable breakthrough in the deep tight oil formation of the Paleogene System in the Pearl River Mouth Basin. The optimized geological and petrophysical evaluation approach by LWD ultrasonic image logs, Stoneley permeability analysis, anisotropy analysis, and other petrophysical logs is a proven and efficient evaluation methodology and can be applied in other complex structural tight oil formations.

Petrophysical Characterization of Volcanic in the Presalt Interval: Image Log and NMR Data, Potential Tools for Characterizing Reservoirs With a Focus on CCUS
Gilberto Raitz Junior, Carolina Ribeiro, Michele Arena, Fernando Neves, and Leonardo Borghi,
Laboratory of Sedimentary Geology (Lagesed)

Volcanic reservoirs within the presalt interval present a unique data set on petrophysical properties, differentiating from the conventional tools in volcanic reservoirs (NPHI, RHOB, and GR). Additionally, with the rising global focus on carbon capture, utilization, and storage (CCUS) to combat climate change, it is imperative to understand reservoirs deeply and use all the data already acquired to be able to choose which rocks and how the characterization will be carried out for future CO_2 reservoirs. Accurate characterization becomes crucial for hydrocarbon exploitation and evaluating their potential as carbon storage sites. This study evaluates the efficacy of image logs and nuclear magnetic resonance (NMR) data in enhancing petrophysical characterization of volcanic reservoirs specifically geared towards CCUS applications using the data set in presalt.

A comprehensive data set (wells in the presalt interval) was compiled, which needed to have the image logs (BHI) and NMR measurements from select presalt volcanic rocks. Image logs provided a high-resolution visual understanding of rock fabric, fractures, and in-situ structures, while NMR data furnished insights into porosity, flow units, and permeability. An integrated workflow was developed, starting with a qualitative analysis of image logs to identify textural variations and fracture networks. Subsequently, the NMR data were processed to derive pore-size distributions, bound and free-fluid volumes, and permeability estimates. A reservoir model was developed, emphasizing reservoir compartments suitable for CCUS.

Integrating image logs and NMR data reveals details of the volcanic reservoirs. Image logs effectively highlighted volcanic textures and fracture orientations, which are crucial for understanding fluid flow patterns. In contrast, NMR data successfully differentiated between macro- and microporosities and delineated zones with potential capillary seals—essential attributes for CCUS storage security—making it possible to map reservoir zones and seals within the volcanic succession. Two primary insights were drawn from the study. Due to their heterogeneity and the presence of natural fractures, volcanic reservoirs in the presalt interval offer potential sites for carbon storage, with zones and trap containment. Combining image logs and NMR data can significantly uplift reservoir characterization, especially in complex formations like volcanic rocks, where conventional profiles (RHOB, NPHI, and GR) are traditionally acquired and may not show relevant information for the characterization of these reservoirs. In conclusion, the duo of image logs and NMR data is a potent tool set for the petrophysical characterization of volcanic reservoirs in the presalt interval. With a particular focus on CCUS, these tools can pave the way for identifying and optimizing volcanic reservoir compartments for sustainable carbon storage, merging hydrocarbon exploitation endeavors with environmental responsibility. However, it is important to mention that these more advanced tools require specific conditions (well diameter), which onshore reservoirs may have yet to have compared to offshore.

Reflection Sonic Imaging Using Slimhole Pipe-Conveyed Sonic Tools
Brian Hornby, Hornby Geophysical Services, LLC; Mark Bacciarelli, Rachel Ospina, and Said Assous, Weatherford International

Modern slimhole pipe-conveyed sonic tools provide formation P- and S-wave slowness as well as high-end products such as cross-dipole anisotropy determination and geomechanics parameters. Reflection sonic imaging is another area of strong client interest; however, to date, the use of slimhole sonic tools for this application has been limited. One objective of this paper is to demonstrate that slimhole sonic tools can deliver results for reflection sonic (P- or S-wave) imaging as good as traditionally delivered by wireline openhole sonic tools. Beyond this objective is to demonstrate that the results can affect drilling or completion engineer’s decisions to, for example, target the next well interval or guide best locations for well fracking.

In order to deliver data suitable for reflection imaging while retaining the data parameters to support the P- and S-wave slowness measurements for the well, the tool needs specific deployment considerations and is programmed to both extend the time recorded for the sonic waveforms as well as expanding the signal bandwidth of the recorded data beyond the default setting. Beyond that, the reflection imaging method and workflow are optimized for processing speed and delivery in time to make the targeted impact. For example, a fast-track processing can be delivered in a day that has 90% of the potential image quality, and a more complex result that is a 100% quality result is delivered some days later. Getting the recorded data to the person performing the imaging as rapidly as possible is one of the goals of this fast-track approach. If necessary, reflection imaging processing can be provided at the wellsite.

Data from several unconventional and other wells are looked at. Integration with other borehole measurements, including borehole wall imaging and other logs, was a key part of the analysis, as well as integration with resistivity imaging when available. Both the fast-track and the expanded processing choices produce positive outcomes. Most interesting wells are extended-reach/horizontal wells where the location of near-wellbore reservoir boundaries of interest is not predictable from any borehole wall imaging results. In the horizontal well portion, this was particularly true for extremely lengthy sections. The accompanying figure shows an example fast-track image in an extended-reach/horizontal well. Here, the arrow points to the imaged reservoir boundary away from the well. In this example, the imaged reservoir boundary is seen from nearly 40 ft away from the well at the bottom of this section to around 10 ft at the top of the section.

Weak Reflection Extraction in Borehole Acoustic Reflection Imaging Using an Unsupervised Machining-Learning Method

Qiang Wang, Hua Wang, and Zhilong Fang, University of Electronic Science and Technology of China; Danian Xu, Xiao Qi, and Yang Yu, China Oilfield Services Limited

With an increasing requirement for detecting subtle fractures and anomalous bodies around boreholes in unconventional reservoirs, borehole acoustic reflection imaging (BARI) is widely employed. In BARI, a small portion of the waves in the array acoustic-logging leaks into the formation and is reflected by geological structures, forming reflections, while the strong guided waves propagate along the borehole. The goal of BARI is to use the reflections to image the tiny and irregular structures 20 to 100 m away from the borehole. However, these reflections are submerged in the strong guided wave and are nearly invisible. Traditional methods, such as F-K transform and SVD decomposition, cannot fully suppress guided waves, resulting in residual guided waves still interfering with the weak reflections. Recently, deep-learning methods have made great progress in many areas, such as image and speech processing. Specifically, many supervised methods are employed to separate wavefields in seismic fields and exhibit good performance. However, they are limited by rare labels in field applications. Motivated by end-to-end speech separation networks, this paper proposes a novel unsupervised machine-learning method to separate guided wave and weak reflections according to their move-out characteristics in common-offset gathers (COG) data.

During the training stage, we feed the multichannel array data from COG measurements into a deep neural network (DNN), which leverages a mature speech separation architecture. Then, the DNN model will generate a rough estimated guided wave for a specified input channel. Subsequently, a Wiener filter can be applied to the estimated guided wave of the specified channel to predict the guided wave at all other channels. Then, we minimize the Frobenius norm between each full wave and its estimated guided wave as the criterion. This ensures the reflections have a maximum move-out difference with the guided waves in the training multichannel array. By subtracting the estimated guided wave from the full wave of the specified channel, we can obtain the clean weak reflections.

Synthetic and field data results illustrate a good performance of our method in which the weakest reflections can reach 33.2 dB compared to the maximum amplitude in the full waveform. We compare our method with conventional F-K transform and SVD decomposition algorithms, yielding signal-to-noise ratios of 6.7 and 12.1 dB, respectively. However, traditional F-K and SVD algorithms still leave a considerable amount of guided wave residue in the enhanced weak reflections, causing them to be unsuitable for subsequent imaging. Additionally, our method is applicable to complicated geological lithologies, such as sandstone and carbonatite.

INTEGRATED OPENHOLE FORMATION EVALUATION

A New Method of Determination Porosity by D-T Neutron Generator and Dual CLYC Detector

Junting Fan, Feng Zhang, and Qixuan Liang, China University of Petroleum (East China); Yuyu Wu, Southwest Oil and Gas Exploration and Development Research Institute

Porosity is one of the essential parameters in conventional oil and gas reservoir evaluation, as well as plays an important role in the calculation of formation saturation and reserves estimation. Neutron-porosity logging based on the Am-Be source is the most commonly used method to obtain formation porosity. However, due to the restriction and safety issues of the Am-Be neutron source, which has been gradually replaced by the D-T source, the energy of neutrons emitted from D-T sources is significantly higher than that of the Am-Be source, resulting in reduced sensitivity of the instrument. At present, related studies have combined information from multiple neutron detectors or gamma detectors to improve the sensitivity of porosity measurement. The double particle detector CLYC ($Cs_2LiYCl_6:Ce$) can detect both gamma and equivalent thermal neutron information, which has been demonstrated in previous studies to be used for information detection in pulsed-neutron logging instruments. In this paper, based on a pulsed-neutron measurement system consisting of a D-T source and dual CLYC detectors, a new method of determining porosity is introduced, which can effectively improve the sensitivity of pulsed-neutron logging in high-porosity formations.

The new pulsed-neutron measurement system consists of a D-T neutron source and a dual CLYC detector. The fast neutrons with 14MeV energy emitted by the D-T source occur inelastic scattering and elastic scattering with the formation nucleus and release inelastic gamma rays, gradually slowing down to thermal neutrons and eventually captured by the formation nucleus. Inelastic gamma rays and equivalent thermal neutron information are recorded by the new detection system with dual CLYC detector, including inelastic gamma count and equivalent thermal neutron count of the near detector as well as the far detector. The conventional neutron-porosity logging method used the count ratio of epithermal neutrons from near to far to establish a relationship with formation porosity. But compared to the Am-Be source, the energy of 14 MeV fast neutrons emitted by D-T exceeds the inelastic scattering threshold of the main elements in the formation, leading to the probability of inelastic scattering increases between high-energy fast neutrons and the formation nucleus, which weakens the proportion of elastic scattering of hydrogen nucleus in the neutron moderation process, resulting in a decrease in the sensitivity of the slowing-down length to determine porosity. Therefore, inelastic gamma rays are used by the new method of determination of porosity to describe the moderation process of high-energy fast neutrons and establish a self-saturation correction factor for porosity evaluation. Then, a new porosity evaluation parameter was combined with the self-saturation correction factor and thermal neutron count ratio, and a new porosity calculation model was established by using the parameter to achieve the purpose of improving the measurement sensitivity of high-porosity formations. On this basis, the numerical calculation model of the detection system is built by using the Monte Carlo simulation method to simulate the inelastic gamma rays and equivalent thermal neutron responses in different lithology and porosity formation so that the method of pulsed-neutron porosity by dual CLYC detector is verified.

The results show that the sensitivity of the new method of determining porosity is significantly better than that of the epithermal neutron counting ratio. When the porosity is 25%, the sensitivity of the new method of determining porosity is 2.37 times that of the epithermal neutron counting ratio. At the same time, the standard deviation of porosity is 17% of the method of epithermal neutron counting ratio, effectively improving the sensitivity and accuracy of D-T source neutron porosity in high-porosity formations.

A New Saturation Model for Tight Sandstones Based on Complex Resistivity Spectra

Wei Duan and Peiqiang Zhao, National Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum; Xiangxi Miao, Sinopec Matrix Corporation; Qiran Lv, National Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum

Tight sandstones are commonly characterized by low porosity and permeability, complex pore structure, and strong reservoir heterogeneity. Thus, it is difficult to accurately calculate the hydrocarbon saturation in tight sandstone reservoirs. The complex resistivity spectra of the rock contain more physical information than the single-frequency resistivity and are sensitive to water content. Electromagnetic logging could provide effective complex resistivity curves. However, the saturation models based on complex resistivity are fewer and have low accuracy. In this paper, the complex resistivity experiment of tight sandstone samples is carried out. The relationships between saturation and parameters of the complex resistivity are analyzed, and a new saturation model of tight sandstone is established.

The complex resistivity spectra from 40 Hz to 10 MHz of 12 tight sandstone samples with permeability less than 0.1 md were measured with an HP4294 impedance analyzer. The samples were saturated with four different concentrations of NaCl solutions. The water saturation of rock samples was varied by nitrogen (N_2) displacement. The complex resistivity data of rock samples under different salinity and saturation conditions were obtained. After that, we used the Cole-Cole model to fit these complex resistivity curves to obtain important parameters, including low-frequency resistivity, relaxation time constant, and frequency factor.

The results show that the complex resistivity spectra of rocks are obviously affected by porosity, salinity, and water saturation. There is a strong correlation between saturation and interface polarization frequency. The lower the water saturation, the lower the interface polarization frequency. Besides, the frequency factor also has a certain relationship with saturation. On this basis, a water saturation evaluation model with interface polarization frequency and frequency factor was established. Specifically, this model contains two equations, which are respectively the relationship between the interface polarization frequency of the water-saturated rock and its salinity and porosity, and the relationship between the ratio of the interface polarization frequency of partially saturated rock to that of completely water-saturated rock, the frequency factor, and the water saturation.

The reliability and effectiveness of the new model were verified. The accuracy of water saturation predicted by the new model is high. The correlation coefficient between the predicted water saturation and the actual measured water saturation is 0.945, which is significantly higher than that calculated by Archie's equation and the model based on the relaxation time constant. The establishment of the new model could provide an application basis for electromagnetic logging data.

An Automated Approach for Presalt Carbonate Depth-By-Depth Elastic Pore Geometry Characterization at Well-Log Scale

Adna Grazielly Paz de Vasconcelos, Gabriel Gonçalves Cardoso, Danilo Jotta Ariza Ferreira, Luciana Velasco Medani, and Giovanna da Fraga Carneiro, SLB

Carbonate rocks present a high chemical reactivity, leading to diagenetic processes such as dissolution, dolomitization, silicification, and cementation. These processes alter the mineralogy and porous space of the original porous medium, thus affecting the petrophysical properties. Notably, the elastic properties and electrical resistivity of carbonate reservoirs are two valuable petrophysical properties heavily influenced by pore shapes. Furthermore, pore shapes may have a large control on pore connectivity, thus also affecting the reservoir permeability. To address these challenges, rock physics models have been developed and refined to precisely evaluate the impact of pore shapes on elastic properties. One of the main inputs of rock physics models is the pore characteristics. However, manually characterizing pores from thin sections, depth-by-depth, is extremely time consuming, expensive, and depends on the expertise of the interpreter. Moreover, the upscale of thin-section interpretation to log scale has its own challenges, factors that could potentially make the rock physics model validation more complex. Motivated by this, we propose a novel approach for the automated characterization of pore shapes within presalt carbonate reservoirs at a well-log scale based on a rock physics inversion framework. By automating this process, we aim to overcome the challenges of manual characterization, ensuring efficiency and accuracy in analyzing the impact of pore shapes on the elastic properties of carbonate reservoirs.

The proposed approach comprises a rock physics inversion algorithm coupled with an automated procedure for characterizing pore geometry on digitalized thin-section images. The rock physics forward model uses pore shapes, geochemical, porosity, and resistive logs as inputs to compute elastic properties. To mitigate the challenges of manual pore space characterization, an inversion algorithm was designed to automatically estimate the aspect ratio and volume fractions depth-by-depth. The solution is obtained by minimizing the difference between the elastic properties measured at the wellbore and those calculated using the rock physics model.

We applied this novel workflow in a presalt well from Santos Basin. The results of rock physics inversion at the log scale were validated by the automated pore geometry characterization outputs obtained through thin-section analysis. In this well, the prevailing pore types are characterized by an average aspect ratio of 0.15, which constitutes about 90% of pore volume. Additionally, round-shaped pore exhibiting an average aspect ratio of 0.70 represents approximately 5% of pore volume. Notably, depths with a substantial proportion of the aforementioned pore types are strongly correlated with high permeability layers. Within a specific interval, the inversion estimated crack-shaped pores account for approximately 20% of the porosity volume. Unfortunately, thin sections were unavailable for this interval, thus preventing direct confirmation of the inversion results. Nevertheless, the wellbore stability is significantly compromised on this interval as evidenced by the caliper log. This considerable washout degree is an event potentially linked to crack porosity, agreeing with estimated pore characteristics. Apart from the conventional method, our developed strategy showed the capacity to automate pore characterization at the wellbore scale in a depth-by-depth approach. This approach substantially reduced the time required for manual pore geometry characterization from days to hours. At the same time, it effectively minimized the subjectivity linked to this task. Current investigations are underway on additional wells from the same oil field. Finally, we are looking for a better comprehension of how the estimated pore geometry would affect permeability and, consequently, hydrocarbon production.

An Integrative Approach Utilizing Well Logs, Thin Sections, Sidewall Core Samples, and Geochemical Data to Characterize and Evaluate the Reservoir of a Well in the Atapu Field, Santos Basin

Leonardo Ventura, Universidade Federal Fluminense and Observatório Nacional (LabPetrON); Guilherme Oliveira Ramos Dos Santos, Observatório Nacional (LabPetrON); Giovanni Chaves Stael, Observatório Nacional (LabPetrON) and Universidade Federal Fluminense

The Santos Basin is the largest offshore basin on the southeast coast of Brazil and is currently the main oil producer in the country, accounting for around 73% of all production in the sector. The large oil reserves in the presalt section correspond to complex lacustrine carbonate reservoirs constituted by the Barra Velha and Itapema Formations. The vast heterogeneity found in the facies of these formations brings several challenges to the characterization and evaluation of these reservoirs. The Itapema Formation comprises intercalations of conglomerates and sandstones in the proximal part and intercalations of carbonates and dark shales in the distal portion deposited during the tectonic regime of the rift phase. Superimposed on the Itapema Formation, the Barra Velha Formation represents the main reservoir and is formed by stromatolitic limestones, microbial laminites, carbonate shales, and microbialites rich in talc and magnesian clays.

An integrative approach was utilized to characterize and evaluate the reservoirs of Well 8-ATP-5-RJS in the Atapu Field. Special and conventional geophysical logs were used in the formation evaluation stage. The results from formation evaluation were integrated into X-ray diffraction (XRD) data reports, thin sections and sidewall core sample images, and drilling reports. The pressure gradient method was used to define the fluid’s contact with data from formation tests obtained through the drilling reports, establishing the oil-water contact at a depth of 5,557 m, the upper part of the Itapema Formation. Different methods to calculate clay (Larionov, NMR) volume and water saturation (Archie, NMR) were used in order to compare the different results from the petrophysical calculations and propose different net pay scenarios for the well. The cutoffs established for the net pay calculation were 6% effective porosity, 50% water saturation, and 20% clay volume.

The well logs show relative cyclicity with GR, resistivity, and sonic peaks, along with low values of porosity and permeability noted through the NMR logs, although not every peak means a decrease in perm-porous values and/or an increase in Fe, Al, Ti, or Si. This behavior comprises intercalation between shrubs and spherulites with laminites. Levels of intense dolomitization and a zone dominated by grainstones and even breccias can also be found. The main types of porosity observed are intergranular; however, it is quite common to find intragranular porosity in spherulites due to fracture or dissolution in laminites. The well generally presents good porosity values, reaching up to 22% in grainstones and 25% in laminites with intense dissolution. However, permeability values present relatively low values due to the large volume of fines and non-interconnected diagenetic porosity, meaning that rock physics crossplots tend to present a trend that is not as clear as for siliciclastic reservoirs. The spectral gamma ray logs present uniform proportional behavior between K and U, except a U peak found in the middle of the Barra Velha Formation; however, it is possible to notice higher values of Th proportionally when compared to the other elements. The XRD data were taken only at specific points and tended to confirm the behavior noted in the geochemical logs. Different cementation and saturation exponents were used to calculate water saturation, using values given in the literature, by the variable m method, and by neighboring fields in the Iara Complex. The set of calculations that presented the most feasible result when related to the well logs and descriptions of thin sections for this well was with clay volume by Larionov and water saturation by Archie, with cementation and saturation exponents of neighboring fields in the Iara Complex, presenting a small but important difference when compared to other sets.

Applications of a New Multiphysics Inversion Technique: Optimized Petrophysical Evaluation of Advanced Dielectric and Spectroscopy Logs in Unconventional Reservoirs
Andrew C. Johnson, Laurent Mosse, Yevgeny Karpekin, Ulises D. Bustos, Violeta Lujan, and Akinlolu Williams, SLB

Numerous comprehensive well-logging suites have been deployed in recent years to assess unconventional oil and gas reservoirs. These technologies produce extensive and rich data sets that, while powerful, can introduce significant technical challenges during integration into formation evaluation workflows. A key challenge arises when integrating advanced dielectric and spectroscopy logs, each of which yields independent outputs for water saturation and salinity through distinct measurement physics. Present workflows designed to reconcile these and other quantities do not rigorously and consistently incorporate known measurement sensitivities and uncertainties and can vary between log analysts. In unconventional reservoirs, they also rely on user inputs of kerogen maturity and hydrocarbon properties, which can be difficult to ascertain a priori. This underscores the need for a consistent, quantitative interpretation methodology that can precisely integrate advanced logs into a formation evaluation workflow.

A novel multiphysics inversion approach has been recently introduced to optimize the various formation property sensitivities of two primary advanced logs: multifrequency dielectric dispersion and geochemical spectroscopy. One of the primary limitations of standalone dielectric interpretation is its insensitivity to salinity estimation at high formation water salinity ranges, which is complemented by chlorine and formation sigma measurements in the multiphysics inversion. Additionally, nuclear magnetic resonance (NMR) porosity, when incorporated into the inversion with the spectral total organic carbon (TOC) measurement, provides unique sensitivities for constraining kerogen and hydrocarbon properties. The multiphysics inversion method quantitatively accounts for these differences in physical sensitivities, as well as their measurement uncertainties, in the solutions for water volume, saturation, formation water salinity, and kerogen and hydrocarbon densities. Combined with advanced mineralogy and porosity evaluations from the logging suites, this methodology produces unified, optimized outputs for advanced well-log interpretation while maximizing the extracted value of the acquired advanced measurement suite.

We present case studies as a first exhibition of the new multiphysics inversion technique, integrated into complete petrophysical workflows, for utilizing multifrequency dielectric, geochemical, and NMR logging tools in unconventional reservoir evaluation. We explore reservoirs in the Permian Basin of the United States, including logged intervals over the organic shale pore-fluid systems of the Wolfcamp Formation. We also include an unconventional oil reservoir evaluation in the Vaca Muerta shale of Argentina. Through these studies, we demonstrate how the standardized multiphysics inversion approach supersedes individualized advanced log reconciliation and minimizes uncertainties in their integration. We provide comparisons to standalone interpretations of each advanced log to illustrate the benefits of a simultaneous inversion with discussions of the limitations presented by each approach. Validation of formation water salinity and kerogen properties is performed against available published local data. Finally, we discuss the conditions under which these workflows can be logically extended to conventional reservoir evaluation and carbon capture and storage (CCS) applications, broadening their applicability well beyond unconventional reservoirs.

Drilling Mud-Filtrate Invasion Modeling for Residual Oil Saturation Estimation
Filipe Ramos de Albuquerque, João Paulo Teixeira da Fonseca, and Gabriel Luiz Pérez Vieira, Petrobras

The invasion of drilling mud filtrate into the formation is a commonly overlooked process. It is generally considered only a well stability and logging environment problem. However, recent studies have shown the potential of petrophysical knowledge involved in understanding this phenomenon. Residual oil saturation (Sor), in a more conceptual definition, is the minimum final hydrocarbon saturation that can be achieved through the action of viscous, capillary, and/or gravitational forces. It is important not only for the total estimation of mobile oil but also for oil production estimates over time, as its value impacts relative permeability models. There are few methods for the estimation of Sor. When it comes to openhole logging, only resistivity, neutron-induced capture gamma ray spectroscopy, and nuclear magnetic resonance (NMR) logs appear as potential candidates, and, even so, they only estimate the remaining oil at the formation, which may be or may not be close to Sor value. Here is where invasion modeling comes in as an alternative to trying to estimate properties that impact invasion, including Sor.

This paper presents a methodology for estimating Sor using invasion zone simulation and microresistivity logs. The workflow followed the logic of applying physics-driven models with a robust theoretical foundation, along with indirect measurements from well logs. The objective is achieved through the adjustment of calculated and simulated water saturations. A one-dimensional (1D) piston-like invasion model, which considers only horizontal flow, is preconceived using the UTAPWeLS software based on known petrophysical properties (Phi, Kabs, and Swi), relative permeability curves, capillary pressure, formation water salinity, and an initial guess value of Sor. A layer-cake model is used to populate the petrophysical parameters. The calibration of the invaded zone saturations, estimated by hydrodynamic invasion model (SxoSim) and microresistivity (SxoArch), the last one being used as the reference curve which the simulation had to match, is done through adjustments of relative permeability and Sor curves for the fluid flow simulation until both SxoSim and SxoArch matches.

This process results in an adjusted Sor curve. Sor data measured from SCAL was used as a reference to validate the resultant adjusted Sor curve. This result provides a formation evaluation product that is uncommon: a real Sor curve calculated at the well scale that can be applied to any water-based mud (WBM) well. Additionally, insights were extracted regarding the quality of laterolog resistivity curves, formation wettability, and relative permeability.

Enhancing Accuracy and Range of Sourceless Density
Marie-Laure Mauborgne, Rubi Rodriguez, Françoise Allioli, Viktoriya Sergeyeva, R.J. Radtke, Fabien Haranger, Benjamin Rouanet, Alexis Pallain, Idris Babahayou, Erwan Tanguy, David Maggs (Retired), and Christian Stoller (Consultant), SLB

The determination of formation density is a fundamental and critical input for reservoir evaluation. At present, this crucial measurement requires a high-activity radioactive source. The sourceless neutron-gamma density (sNGD) measurement based on a pulsed-neutron generator and introduced in logging-while-drilling (LWD) technology more than a decade ago eliminates the radioactive source and the issues associated with its handling, transportation, storage, and abandonment.

This sNGD algorithm has limitations in high-density formations, shales, large boreholes, and heavy mud. A new sourceless density algorithm has been developed using newly available nuclear modeling capabilities and provides a radical improvement to get closer to the accuracy of the gamma-gamma density (GGD) while covering a wider range of environments.

Inelastic gamma rays generated by high-energy neutron interactions with nuclei in the formation provide the foundation of the measurement. However, it is difficult to properly separate gamma rays generated by inelastic reactions from those generated by capture using only the gamma ray detector. New modeling capabilities allow a better separation of inelastic and capture gamma rays and the proper subtraction of the capture background from the total signal. One new, essential step was to combine modeling results with careful analysis of experimental data to define a new inelastic-capture separation function.

The new measurement modeling, which accounts for the neutron-pulsing scheme and the detector and electronics response, has been benchmarked against experimental data for validation with excellent results. This state-of-the-art modeling approach and the new capabilities have made it possible to re-engineer the sourceless density algorithm, using the latest experimental data available and expanded modeling and machine-learning technologies to realize the full potential of this sourceless measurement. The new algorithm includes environmental corrections based on modeling and experimental data combined with other nuclear measurements such as sigma and spectroscopy. In addition, an improved multipoint tool calibration procedure reduces the impact of tool-to-tool variability by 30%.

The new sourceless density is evaluated globally and has already shown the expected improvements in various challenging environments. The robustness and improved accuracy of the measurement in high-density formations and in shales have been confirmed, and the extended sourceless density range (from 2.8 to 3.05 g/cm^3) now matches the GGD (traditional gamma-gamma density) range. The figure shows the GGD vs. new sourceless density crossplot in one well.

The density measurements combined with the matrix density obtained from the concurrent spectroscopy measurement allow for estimating the formation's porosity. To quantify the impact of new sourceless density, the density porosity in the reservoir section was computed with both densities. The difference between the average porosities is 0.006 v/v, which is sufficient for accurate volume determination. The improvement in accuracy and range of new sourceless density allows for eliminating radioactive sources with confidence for sourceless logging.

Enhancing the Thomas-Stieber Model With Sonic Log Data for Improved Prediction of Clay Geometries and Total Porosity in Shaly Sands

Tariq Saihood, Michael T. Myers, Lori A. Hathon, and Gabriel Unomah, University of Houston

The Thomas-Stieber method has been widely used to evaluate clay-rich, thin-bedded clastic reservoirs by accounting for the distribution of clay minerals within the rock matrix. In such reservoirs, clay content has a profound impact on porosity and, consequently, hydrocarbon storage. However, the limitations of the conventional model have prompted the development of an extended version, which incorporates sonic log data as a crucial third axis in the analysis.

The extended Thomas-Stieber model with sonic log integration hinges on three key variables: the volume fractions of dispersed clay (Xd), laminated clay (Xl), and structural clay (Xs). The approach begins with the derivation of equations for total porosity, gamma ray response, and effective P-wave slowness. These equations are formulated iteratively, introducing heterogeneous clays and quartz into the matrix using Wyllie's time-average equation and the Thomas-Stieber model. Numerical solutions are then obtained for Xd, Xs, Xq, and Xl. To predict effective slowness, our focus is primarily on horizontal P-wave slowness. A three-dimensional grid template is devised to visualize the evolution of total porosity associated with different clay/shale components, wherein the axes are gamma ray, bulk density, and sonic log responses.

The grid template reveals distinct relationships between clay types, total porosity, and P-wave slowness. Structural clays exhibit a positive correlation with total porosity, whereas laminated clays show an inverse relationship. Dispersed clays also exhibit an inverse relationship with porosity and with P-wave slowness. The incorporation of acoustic well-log data enhances the model's sensitivity to structural clays. The extended Thomas-Stieber model is calibrated and applied to well-log data from a shaly-sand reservoir, yielding valuable insights into the volumetric fractions of Xd, Xs, Xq, and Xl. This study introduces a novel extension of the Thomas-Stieber model by integrating sonic log responses, thus enabling a more nuanced assessment of clay distributions and their impact on porosity in shaly sands. This improved model offers enhanced accuracy in reservoir characterization and simulation, ultimately contributing to more precise hydrocarbon reserve estimations.

Estimation of Permeability Combining NMR-Derived Viscosity and Downhole Fluid Mobility: A Case Study From Offshore Mexico

Nicole Stadt, Wintershall Dea; Mohammad Azeem Chohan, Amer Hanif, Alisa Kukharchuk, Steve Smith, Rex Sy, and Maurizio Briones, Baker Hughes

Formation permeability is a key petrophysical property that defines the producibility of subsurface formations. Nuclear magnetic resonance (NMR) logs are commonly used to estimate near-wellbore permeability; however, NMR permeability models are empirical in nature and often require core data for calibration. Collecting and testing downhole cores is a costly, time-intensive process. Formation pressure testing and sampling (FT) data provide a measure of fluid mobility, which requires viscosity to translate to permeability. A case study from offshore Mexico is presented to demonstrate that the integration of NMR and FT can provide a meaningful estimate of permeability in near-real time.

NMR data are inverted in two-dimensional $D\text{-}T_{2int}$ space to identify and quantify fluid types. Different NMR viscosity models are tested to estimate the viscosity of formation oil and that of any mud filtrate detected. Drawdown rates and pressure drop data from downhole formation tests provide mobility estimates at tool stations. NMR and FT data are combined to first estimate permeability at FT station depths and then use these points to calibrate NMR log permeability from the Coates-Timur model.

Coates-Timur permeability, determined from a default parameter setting, initially did not agree with FT permeability estimates; however, a good match was achieved between the two by a small adjustment to Coates parameters. The study includes a comparative analysis of permeability measured by NMR vs. FT and the advantages and limitations of the proposed methodology. We assess the effect of cleanup during pumpout and of near-wellbore damage on pre- and post-mobilities and how the effects can impact reconciliation with NMR permeabilities.

A relatively simple exercise of combining FT mobility and NMR viscosity benefits customers with an improved and consistent measure of reservoir permeability. In a high-cost deepwater drilling environment, this enables quicker decisions.

High-Angle Formation Evaluation in Layered Formations Using Dual-Arrival Sonic, Borehole Image, and Geosteering Electromagnetics Measurements

Nicholas Bennett, J. Adam Donald, Mustafa A. Mubarak, and Sherif Ghadiry, SLB; Olusegun Akinyose and Shouxiang (Mark) Ma, Saudi Aramco; Hiroaki Yamamoto and Wael Abdallah, SLB

High-angle or horizontal well analysis using borehole sonic data has been routinely used as input to stimulation design, geological mapping, or petrophysical analysis for almost two decades. Often, multiple coherence events are detected at the layer boundaries, and uncertainties arise as to which event corresponds to a specific layer. The variations in the interpreted slownesses can lead to uncertainties in interpreted porosity up to 9% for carbonates and inaccurate mechanical properties leading to under-optimized stimulation.

The main issue is that standard sonic processing methods such as slowness-time coherence (STC) assume that these sonic measurements are responding to a single formation layer, while the resulting multiple compressional and shear slowness values (called “dual arrivals”) indicate, in fact, that the sonic measurements are responding to multiple subparallel formation layers along these high-angle wells.

We introduce new methods to convert these multiple-arrival sonic events into (a) logs of tool layer and shoulder-bed slowness and (b) two-dimensional (2D) curtain sections of compressional and shear slowness along the well track in a manner analogous to the corresponding curtain section of horizontal resistivity derived from directional geosteering electromagnetics measurements.

We observe that in high-angle wells, these multiple-arrival sonic arrivals arise as refractions and reflections from nearby shoulder beds (the “shoulder-bed arrivals”) and as sonic arrivals that propagate directly from the source to the receiver array in the tool layer (the “tool layer arrivals).

These shoulder-bed and tool layer arrivals present very different moveouts as functions of measured depth in the common offset gather domain, source-receiver offset in the common shot gather domain, and nominal receiver azimuth in the common ring gather domain, so separating and characterizing these arrival events require the sonic tool’s full three-dimensional (3D) array of receiver sensors. We demonstrate how tau-P transforms (typically used to detect line segments in images) can be used to accomplish this task.

The tool layer compressional and shear slowness values derived from these tau-P results are formed into their corresponding logs to provide accurate formation evaluation answers for the layer(s) containing the well track and nearby shoulder beds.

A ray tracing inversion further processes these tau-P results to resolve the distance to, relative dip of, and slowness of a nearby shoulder bed and, subsequently, a 2D curtain section of formation compressional and shear slowness.

This workflow represents the first time that sonic measurements have been used to determine the slowness value of a shoulder bed along a high-angle well.

We demonstrate this workflow on both modeled and field measurements acquired on standard or slim sonic logging platforms with azimuthal receivers. The case studies include a high-angle geothermal well in an interbedded limestone/oolite formation as well as in other carbonate and shale formations. We show joint interpretation with borehole resistivity and density images where we observe the dual-arrival events responding to the formation structure. This workflow is deployed using edge computing with a multinode cluster at the wellsite to produce the results in operational time so that they can be used for completion decisions. This is the first time that this type of high-performance computing has been used to meet operational times, delivering results in a matter of hours.

The results of the tool layer and shoulder-bed slowness logs provide new layer-by-layer geomechanics and petrophysics formation evaluation answers (porosity, Poisson’s ratio, and Young’s modulus).

Implementation of a Laminated Sands Data Acquisition Strategy Delivers Improved Accuracy of Reserves and Rate Forecasting: A Case Study From Trinidad and Tobago
Arden Burrowes, Warren J. Lall, Jason Frederick, Rajiv Bridglal, and Zorie Jones, Heritage Petroleum Company Limited; Alisa Kukharchuk, Amer Hanif, Oluwaseun A. Savage, Mohammad A. Chohan, and Rishi Ramdhanie, Baker Hughes

The Soldado oil fields, off the southwestern coast of Trinidad, consist of several stacked, heavily faulted reservoir compartments. The fields have been on production since the 1950s. As a mature oil province, there have been challenges in finding commercially viable opportunities in previously unpenetrated compartments. Though there is abundant log, fluid, and core data in the newer wells drilled in the past few decades, conventional log data suites, such as the triple combo (density-neutron-resistivity), have historically struggled to accurately resolve and quantify the hydrocarbon volumes in thin-bed laminated sand-shale sequences. A novel data acquisition and integrated analysis methodology has been implemented for the Soldado fields. The logging and core acquisition program has been designed to better understand reservoir anisotropy, which impacts the production strategy of current and future wells in the current drilling campaign. Reserves volume and oil production rate forecasting for these unconsolidated sands are improved by building a dynamic reservoir model and updating it with the outcome of the static petrophysical analyses of the latest drilled wells.

Conventional logging measurements in the first well of the logging campaign struggled to resolve the presence of laminated oil sands between shales. Learning from this outcome, modifications were made to the data acquisition strategy to better understand reservoir anisotropy. Nuclear magnetic resonance (NMR), wellbore image, triaxial resistivity, and rotary sidewall core data were added to the planned data acquisition program to better appraise the lesser-developed reservoir packages. In the subsequent wells in the campaign, the addition of the triaxial resistivity combined with the NMR and borehole images provided enhanced resolution, allowing a more detailed reservoir stratification model. This model was used to specifically quantify the sand laminae porosity, saturations, and net pay thicknesses. NMR data are used to accurately define and incorporate bulk clay bound, effective, and total porosities. Isolation of flow units was an important consideration for well completion design and was established through the study of borehole images and NMR free-fluid index. Integration of these advanced data sets has not been attempted in this area previously to this extent.

Whereas some sand packages were observed to be uniform/isotropic, thin laminations and significant resistivity anisotropy were measured across deeper sand packages. The net sand pay was similar between the conventional and laminated shaly-sand methodologies applied to laminar sands; however, the laminated sand saturation model more accurately estimated effective porosity in the thin-sand layer. An increase of 20% in cumulative porosity and cumulative hydrocarbon volume was obtained. A key benefit of this integrated approach was the revelation that a substantial barrier was present between key reservoir flow units, which will impact the production plan for the subsequent well if a gassy oil scenario is encountered in the upper flow unit. This paper discusses the relatively novel approach successfully applied in the region for this mature oil province.

Integrated Workflow Utilizing LWD GR-Resistivity, Advanced Mudlogging, and Well Dynamic Data Enabled Petrophysical Parameters Modeling to Assist Geosteering in UBCTD
Ibrahim A. Mohd and Faizal N. Enezi, Saudi Aramco; Enrico Zipoli Ferreira, Baker Hughes

This article proposes a direct correlation between logging-while-drilling (LWD) gamma ray (GR) and multiple propagation resistivity (MPR), advanced mudlogging sampling analysis, and surface logging data to characterize poro-permeable formations. Integrated workflow enables reservoir navigation and real-time petrophysical multiparametric modeling through data scientific method to define net gas productive zones in underbalanced coiled tubing drilling (UBCTD), whereas the productivity index is defined as a quality indicator of net pay zone drilled within.

This method pioneers proactive reservoir navigation in ultraslim wells that utilize coiled tubing. The challenge to overcome is the diameter of the LWD tools deployed in this environment, which limits several technologies in the oil and gas industry. Thereby, real-time multicomponent-while-drilling (MCWD) inversions, described as a multiparametric algorithm to describe complex models with multiple layers from resistivity measurements, are allied with real-time multiparametric petrophysical modeling through the KNN method, which includes advanced sampling analysis of lithology and gas drilling dynamics in UBCTD environment.

The underbalanced net gas production is a direct reading of the well productivity index and qualifier of this method, which preemptively disallows erroneous interpretation of poro-permeable layers from the reservoir navigation workflow described in this article.

The novel approach in this integrated workflow enables reservoir navigation and real-time correlation of petrophysical models with offset well porosity and permeability. Results highlight a cornerstone in either clastic or carbonate environments, with increased net-to-gross and productivity index of this dynamic application of UBCTD, which demands no space for errors. In this paper, we will present an integrated workflow that led to a successful UBCTD well in a carbonate layered formation. The application of this workflow influenced the geosteering decisions by confirming the reservoir petrophysical parameters of the drilled section. The results will be incorporated into the geological correlation and navigation model and can lead to the modification of well trajectory if the penetrated reservoir is not meeting the expected quality in order to improve the reservoir contact.

The value of this approach currently contributes to the success of UBCTD development wells and is a limitless possibility of worldwide untapped reserves. Moreover, the coiled tubing allied with this workflow can reduce carbon footprint by minimizing nonproductive footage drilled and optimizing well placement investment and return on investment.

Fig. 1—Illustration of inversion result mapping internal conductive features correlated to real-time LWD resistivity data. Identification of apparent dip can be applied to inform gesoteering recommendations.

Inversion-Based Multiwell Petrophysical Interpretation of Well Logs and Core Data via Adaptive Rock Physics Models
Joaquin Ambia and Carlos Torres-Verdín, The University of Texas at Austin

Formation evaluation, and specifically hydrocarbon volume estimations, are tightly dependent on the rock physics model (RPM) used for the interpretation of well logs and core data. The latter models are known to exhibit small but significant variations throughout multiple wells located in the same hydrocarbon field. To improve the accuracy and reliability of the interpretation, the RPMs are typically adjusted ad-hoc. We automate the multiwell interpretation process by relying on local petrophysical inversion of well logs and core data. A spatial correlation function is used to implement the RPMs, both vertically and laterally. In addition to improving formation evaluation in each well, our inversion-based method mitigates layer-boundary, geometrical, and instrument-related effects on well logs and identifies data outliers and measurement imbalances where further quality control might be needed.

First, we invert each available well log into an equivalent physical property represented by a layer-by-layer blocky log with an associated uncertainty (earth model: piecewise constant layers with discontinuities at layer boundaries). This mitigates any tool, shoulder-bed, or borehole-condition dependency. Then, we use the extra measurements (well logs and core data) from a key well to determine an initial RPM (e.g., Juhasz parameters and density of minerals), as well as probabilistic prior distributions for all properties, e.g., porosity and water saturation. Next, we propagate the RPM and prior distributions throughout the field using Bayesian petrophysical/compositional joint inversion (PJI) for all petrophysical properties in every well, concomitantly propagating uncertainties to petrophysical/compositional properties. With each non-key well having a full set of physical (from well logs) and petrophysical/compositional properties, we generate new priors and RPMs for each well by minimizing the PJI misfit. These new priors and RPMs are used to further refine priors, and RPMs on neighboring wells. We enforce consistency via spatial variograms for RPMs. The process is repeated iteratively while tightening the variogram until no further improvement is possible. This method guarantees that the variation of RPMs is consistent across spatial correlations. The accuracy of the method is improved as more field data are available to corroborate and refine local RPMs and prior distributions.

By using adaptive RPMs over tool and borehole-condition-mitigated layer properties, we were able to match core data constituted by porosity, fluid saturations, and mineral composition. Our results replicated 87% of the core data within the 95% confidence interval; in contrast, using a universal RPM replicates a lower 80% of the core data within the 95% confidence interval. Traditional interpretation methods cannot capture confidence intervals and yield significantly poorer matches in all properties; when comparing specifically hydrocarbon pore volume, our method shows an average 5% accuracy improvement.

We generalized a logging tool and borehole-condition-independent Bayesian inference petrophysical estimation method to a multiwell framework. By considering the entire hydrocarbon field as a single petrophysical joint inversion of well logs and core data, we increased the accuracy of formation evaluation and/or identified outliers or data imbalances that signaled poor or biased data that required further quality control.

Novel Method for Estimating Water Saturation in Gas Reservoirs Using Acoustic Log P-Wave and S-Wave Velocities
Sheyore John Omovie, Goshey Energy Services LLC

It is well established in rock physics that when the fluid filling the pore spaces of a reservoir is primarily gas or light oil, there is a significant change in the bulk modulus but little to no changes in the shear modulus when compared to fully brine-saturated reservoirs. This, in turn, leads to a lower velocity ratio in gas or light oil reservoirs. This concept underlies and has been extensively used in the fluid identification of conventional siliciclastic reservoirs in seismic interpretation. Yet, there is not so much in the use of higher-resolution sonic logs. Here we ask the question, can we use sonic logs to not just identify but quantify hydrocarbon saturation in gas reservoirs? Using sonic logs, can we accurately estimate water saturation with uncertainties that are similar to those obtainable from conventional saturation models? If possible, this would have significant implications in the evaluation of shaly-sand reservoirs as well as low-resistivity, low-contrast reservoirs, where conventional saturation models may not be as effective.

Given P-wave and S-wave velocities computed from measured compressional and shear sonic logs, a new empirically derived saturation model for estimating water saturation is presented. One that does not require formation resistivity or brine salinity. The new model is based on the lower bulk modulus or velocity ratio observed in gas reservoirs. Assuming the reservoir is fully brine saturated, the deviation of the measured P-wave and S-wave velocities from the fully brine saturated velocities is used to invert for water saturation. The new model is shown to be consistent with theoretical rock physics models.

We apply the new model to compressional and shear sonic well-log data acquired in eight different wells and six different formations. The reservoirs range from an organic gas shale reservoir to a gas sand reservoir offshore the Gulf of Mexico. In one of the organic shale examples, the Haynesville shale average water saturation from the new model was 33% compared to 34% from the conventional saturation model that has been calibrated to tight rock core analysis. In the Gulf of Mexico gas sand example, the model yields 24% average water saturation compared to 21% average water saturation from the core-calibrated Archie saturation model. The attached figure shows how the model compares to the Archie saturation model and core data for the Gulf of Mexico gas sand example. In a low-resistivity, low-contrast, shaly-sand reservoir where conventional saturation models indicated the reservoir is wet, the new model yields results that are consistent with gas production from the reservoir. We also present the results of the application of the new model to a gas condensate reservoir in the North Slope of Alaska and an oil reservoir offshore the Gulf of Mexico.

Further work is ongoing to evaluate application to more oil reservoirs as well as potential application to carbon sequestration monitoring.

Perched Water Observations in Deepwater Miocene Fields Using Well Logs, Core, and Production Data

Alexander Kostin and Jorge Sanchez-Ramirez, Woodside Energy

Perched water is occasionally encountered above the main gas- or oil-water contact in stratigraphically and/or structurally complex fields. It is a consequence of localized water entrapment associated with relatively small-scale structural or stratigraphic traps during the migration process. Observations of perched water intervals and their associated transition zones in the exploration, appraisal, or production wells can challenge subsurface characterization workflows and often lead to inaccuracies in in-place volumes estimation. Perched water transition zones are commonly misinterpreted as lithological trends, while local perched contacts found at the bases of sands could be interpreted as segment or field-wide contacts. It is, therefore, important to recognize the presence of perched water and adequately characterize its impact on reservoir volumetrics and production volumes.

We present examples of perched water intervals in two Miocene deepwater fields. In the first example, a clear transition zone associated with perched water is observed in a fully cored gas-bearing sand located several hundred feet above field gas-water contact. The presence of movable perched water is confirmed via direct extraction from core samples (see Fig. 1). The associated saturation profile is evaluated using logs and special core analysis measurements. The chemical composition of extracted water samples is compared with the aquifer waters. In the second example, we present a case of perched water in a reservoir located hundreds of feet above regional oil-water contact. Perched water was detected by comparing resistivity- and capillary-pressure-derived saturation profiles and confirmed with water sample analysis and production data.

The field cases provide examples of movable water located high above field water contact and offer useful analogs for perched water detection in deepwater sandstones. Perched water transition zones saturation is shown to follow a normal drainage capillary pressure profile, and its chemistry differs from the aquifer waters. Perched water pools appear to have a limited volumetric footprint and do not result in large quantities of produced water; however, they still need to be accounted for as a potential risk in deepwater projects.

Petrophysical Joint Inversion for the Estimation of Compositional and Storage Properties of Thinly Bedded Reservoirs: A Fully Statistical Approach

Joaquin Ambia, David Gonzalez Isaza, and Carlos Torres-Verdín, The University of Texas at Austin

To develop a new statistical method for the estimation of petrophysical properties (water saturation, porosity, shale concentration, mineral, and fluid composition) and storage properties (net-to-gross and hydrocarbon pore thickness) from well-log-equivalent physical properties (e.g., resistivity, density, neutron, density, PEF, slowness). The statistical method considers probability distributions for every variable, allowing the calculations to have full variability of possible conditions. All the results are presented with confidence intervals for better formation evaluation.

The process can be divided into two steps. First, we take physical-property-equivalent well logs and turn them into earth model properties, which are piecewise constant with discontinuities at each bed boundary. This model is usually referred to as a “blocky well log,” but we go a step further, and instead of having a single value to describe each property in each layer, we have a probability distribution. This can be understood as, instead of describing the density of a layer as 2.56 g/cc, we now describe it as between 2.54 and 2.57 g/cc with a confidence of 95%. Furthermore, by relying on earth model properties rather than directly well logs, we mitigate any future calculation/estimation from instrument and specific borehole environmental conditions.

In the second step, we start from the aforementioned physical properties and calculate petrophysical properties using Bayesian inference. We generate prior probability distributions from previous knowledge of the field or known endpoints. The priors will be the foundation for a Latin hypercube sampling grid of the possible compositional solutions; this is a number of conditions with fully defined porosity, shale concentration, water saturation, and mineral and fluid compositions. Each of these conditions has associated physical properties easily obtained by performing forward calculations (e.g., nuclear properties, resistivity, and sonic slownesses). Then, we also associate a probability distribution to each of these conditions for each layer by comparing the calculated physical properties to those of each layer. Ultimately, we have a probability distribution for each petrophysical property in each layer, which can easily be used to calculate storage properties and their probabilities.

One of the most relevant features of our method is the fact that we are performing full calculations rather than relying on endpoints, which is important for nonlinear models, e.g., nuclear porosity, resistivity, and slowness. None of the compositions are assumed to be fixed, i.e., shale can have variations (small or large) in porosity or composition. The forward model can include restrictions for shale structure (e.g., laminar vs. dispersed), yielding more accurate results when anisotropy is present. Furthermore, the stochastic search enables a thorough investigation of possible solutions, avoiding any local minima trapping. Lastly, because our method does not rely on inverting matrices but rather prior distributions, there is no constraint between the number of unknowns and the number of equations used (well-log-related physical properties).

We applied our method to several field data sets. Using core data as ground truth, we compared our results to those of conventional methods. Using a 95% confidence interval, our results captured more of the total porosity: 91.4% vs. 71.8%. Results obtained from the two methods performed equally when estimating water saturation (both 70.3%), while the cumulative hydrocarbon pore thickness showed a 7% difference between the methods.

Physics-Based Probabilistic Permeability Prediction in Thin-Layered Reservoirs: Transport Theory, Dielectric Dispersion Logging, and Core-to-Log Bayesian Statistics

Marco Pirrone, Nicola Bona, and Maria Teresa Galli, Eni S.p.A.

Accurate permeability prediction is probably the most challenging issue in reservoir characterization, and, at the same time, it is one of the most desired targets. Conventionally, a permeability profile is inferred from core-calibrated algorithms applied at the well location to different openhole logs. However, as the models are not exact, and the assumptions are not always satisfied, the uncertainty attached to the results is high. This uncertainty is even higher in thin-layered reservoirs characterized by bed thicknesses well below the resolution capabilities of standard logging tools. In this respect, the paper deals with a novel physics-based probabilistic methodology for high-resolution permeability estimation. This relies on core data and dielectric dispersion logging (DDL). Its cm-scale vertical resolution and the related fit-for-purpose petrophysical model make the DDL tool response suitable to capture and describe the permeability heterogeneity of these very thin laminated scenarios.

The approach is presented by means of a study performed on several wells drilled and (a few of them) cored into gas-bearing distal turbidite reservoirs. Their exploration and production are particularly challenging due to the presence of thinly bedded sections with individual laminations sometimes thinner than 1 cm. DDL can be a useful tool to characterize these thin-layered scenarios since the response of rock to electromagnetic fields at different frequencies is a good indicator of its components and microscopic structure. A dedicated interpretation model has been developed to invert DDL data and obtain high-resolution (cm-scale) estimates of shallow water volume fraction, shallow water salinity, and a textural parameter that is correlated to cation exchange capacity (CEC). Permeability is then computed from a physics-based analytical model taking advantage of transport phenomena in composite materials, effective medium theory, dielectric dispersion modeling, and selected core data (i.e., grain-size distribution and CEC). All the input parameters of the proposed methodology come from DDL outcomes embedded into a core-to-log Bayesian framework. This generates a high-resolution permeability profile, together with the associated uncertainty.

The match with core measurements in key wells proves to be very accurate. The prediction capability has also been demonstrated on dozens of wells by comparing DDL-based permeability to wireline formation tester results (considering the differences in scale and lateral extent of the techniques). It is worth noting that the major strength of the method relies on the fact that no additional calibrations and/or adjustable parameters are needed.

This new approach is now routinely and successfully utilized to evaluate permeability in uncored and untested wells intercepting such challenging environments. Given the high vertical resolution of the DDL tool, it is one of the few methods suitable for thin-layered reservoirs.

Research and Application of Fracability Evaluation Method for Tight Sandstone Reservoirs Based on Logging and Experimental Data

Yuping Qian, China Oilfield Services Limited; Wenwen Wang, China United Coalbed Methane Co., Ltd.; Huizhuo Xie, China Oilfield Services Limited

In recent years, onshore and offshore oil and gas exploration has gradually moved towards the field of low porosity and low permeability. The development of such reservoirs requires hydraulic fracturing. Therefore, research on engineering fracability evaluation has increasingly attracted attention from major oil and gas fields.

This study takes the tight sandstone gas reservoir on the northeast edge of the Ordos Basin as the research object. Based on well-logging data, rock mechanics, and rock physics experiments, a comprehensive brittleness evaluation method considering the influence of minerals and microcracks is proposed for the study block. Then, the fracability of reservoirs is evaluated considering four factors: the difficulty of generating hydraulic fractures, the longitudinal expansion ability of fracturing, the radial extension direction of fracturing, and the complexity of the fracturing network from the perspectives of the generation and development of fracturing. Specifically, taking into account the strength and brittleness of rocks, the difficulty of producing fracturing cracks was comprehensively analyzed. The longitudinal expansion ability of fracturing fractures through the thickness of the barrier layer and the differences in properties between the reservoir and the barrier layer (such as rock strength, brittleness, lithology, stress, etc.) was discussed. Then, the radial extension direction of the fracturing fractures through the orientation of fast shear waves obtained through acoustic anisotropy inversion, induced fractures, or wellbore collapse was determined. The complexity of the fracturing fracture network is analyzed based on parameters such as rock brittleness, microcracks, bedding, natural fractures, and horizontal stress difference coefficient. Among them, the evaluation of microcracks relies on stress sensitivity experiments, the evaluation of bedding relies on velocity anisotropy experiments, and the calibration of in-situ stress relies on acoustic emission Kaiser experiments under confining pressure.

The application examples show that reservoirs with good fracability have a significant increase in production capacity after fracturing, and there is also good consistency with the analysis of the fracturing effect (fracturing height) and fracture network morphology evaluated using acoustic data. The application of examples confirms that the understanding of fracability analysis is reliable and accurate.

Thomas-Stieber Plots Viewed as the Source Data for Staged Effective Medium Models

Michael Myers and Lori Andrea Hathon, University of Houston

The Thomas-Stieber (T-S) model is interpreted in the context of a staged differential effective medium model (SDEM) to model rock properties accurately. The T-S plot is used to identify the clay geometry of dispersed vs. laminated and structural clay in thin-bedded, shaly-sand reservoirs. This model distinguishes the clay laminations from dispersed clay and sand by calibrating the different rates of porosity change due to the differing distributions of clay. The impact of the clay on porosity depends on the length scale with which the clay is distributed. The original T-S model is extended by allowing the dispersed and structural clay porosity and gamma ray responses to differ from the laminated clay porosity. Dispersed clay reduces porosity because it directly replaces the pore fluid. Structural clay increases porosity because it replaces zero-porosity quartz grains. Clay laminations may either increase or decrease the porosity depending on whether the porosity of the clay lamination is higher or lower than the sand it replaces. The equations describing the net/gross (N/G) and the massive sand porosity are derived and provided in compact form. This extension is important to include, particularly if large amounts of pore-filling clays are present. SDEM models allow the different length scales to be included in the models. They are developed by including multiple integration steps in effective medium models. A percolating host is initially assumed with increasing length scale inclusions added. These volumes are obtained from the T-S plot. This allows differing properties associated with connectivity to be included.

The use of a calibrated T-S model requires a knowledge of both the dispersed clay porosity and the interbedded shale porosity. Thin-section analysis is typically used to determine the sample dispersed clay volumes and the resulting macroporosity. Correlations between laboratory-measured total porosity and volumes of dispersed clay may also allow dispersed clay porosity to be estimated. This additional degree of freedom is particularly important when large volumes of dispersed clay are present. Accurate determination of N/G may be made from thin-section analysis at a fine scale or well logs at longer length scales. Different mixing equations are used for modeling differing rock properties. Electrical properties are modeled using a nonlinear mixing rule (multiple iterations of the Hanai-Bruggeman equation). Acoustic properties are modeled using a novel linear mixing rule. These two mixing rules will be introduced in the paper.

Examples are given for resistivity, acoustic, and permeability calculations. The examples show excellent agreement with the core data for all three models. The inputs all use the same Thomas-Stieber plot to

establish the clay volumes. The resistivity model correctly accounts for the variation in tortuosity with the volume of dispersed clay. The permeability model tracks the NMR measurements for permeability over the entire range of measured data. The velocity model demonstrates the importance of structural clay estimates.

The modeling represents an accurate portrayal of the length scales present and the differing impact they have on petrophysical properties. The staged differential effective medium technique allows these length scales to be incorporated. Since macroporosity is the control of many rock properties, quantitatively determining it is important for accurate results. Quantitative estimates of N/G are also a major factor in determining hydrocarbon volumes. Because of its increased accuracy, an extended T-S analysis combined with a physics-based SDEM model allows rock properties models for velocity, resistivity, and permeability to be developed.

Use of A-Priori Information to Improve Automatic Electrofacies Classification: A Case Study in Brazilian Presalt Carbonates
Eduardo Oliveira, Petrobras S.A.

The classification of supervised electrofacies is typically based on defining characteristics or patterns of electrical logs that distinguish rock facies or facies associations. Due to significant similarities in log responses and rapid vertical variation between depositional facies associations used in reservoir modeling, the conventional approach of electrofacies through multivariate analysis of logs commonly does not yield satisfactory results in Brazilian presalt carbonates. To overcome this issue, alternative methods of classification have been used, such as the one based on the interpretation of image logs supported by the description of sidewall cores. However, this approach is highly dependent on the availability of rock data, presents a high degree of subjectivity, and does not quantitatively consider the information from other logs. Therefore, a facies classification method was sought that considers information from rock data, conventional logs, and image logs.

Initially, the faciological classification of sidewall cores was expanded vertically based on image logs. In this step, intervals with typical characteristics in the image logs were also classified. In the next step, the remaining intervals were classified using discriminant analysis with conventional logs. In the Bayesian approach of discriminant analysis, the prior probabilities of the considered classes were modified, allowing the use of other types of information in the classification process besides the logs. Thus, the prior probabilities of the facies were adjusted to reconcile the resulting classification with the observed facies proportions in sidewall cores or correlation wells. This difference from conventional multivariate analysis, which assumes equal prior probabilities among classes, minimizes classification problems caused by the similarity of log responses. Additionally, based on the probabilities of facies a posteriori, it was possible to perform uncertainty analysis of the classification by generating n realizations of the classification using the Monte Carlo method.

The adopted method yielded consistent results with the available data and the reservoir’s conceptual model while also allowing for facies classification in the recent context of reservoir data acquisition, characterized by LWD logs and the absence of rock data.

Validating the Need for Quantitative Estimates of the Properties of the Various Shale Components in the Thomas-Stieber Plot
William Horvath, Lori Hathon, and Michael T. Myers, University of Houston

In thinly bedded, shaly-sand reservoirs, a Thomas-Stieber model is used to quantify volumes of clean sandstone from that of laminar, dispersed, and structural shales. In the absence of a whole core data set, this is done using a log-based volumetric lithologic indicator (i.e., gamma ray) and porosity, which is often inverted from the bulk density data set. The Thomas-Stieber model typically assumes all types of shales have the same properties. This is consistent with observations in the Miocene section of the central Gulf of Mexico, where the model was developed. However, in more heterogeneous thin-bedded reservoirs, refinements to the original Thomas-Stieber model may be appropriate. In a recent publication [SPWLA-2023-1666], it was shown that using segmented thin sections and SEM images that dispersed shale properties are not equivalent to those of the interbedded shale laminae. Because the quartzose framework of the reservoir supports the weight of the overburden, dispersed clay porosity was observed to be twice that of the laminar shale porosity. In this case, both the total porosity and the macroporosity calculated using the standard Thomas-Stieber model for interbedded sandstones will be overestimated.

In addition to the presence of dispersed and laminar shales, the system is complicated by the presence of structural shale in the reservoir. Because the microporous shale clasts replace zero porosity quartz grains in the rock framework, the result is an increase in total porosity. This is depicted on a “typical” T-S triangle as porosity, which lies above the varying net-to-gross clean sand line. When significant volumes of shale laminae, dispersed shale, and structural shale occur together, reliability diminishes for calculating accurate shale volume (net:gross) and clean sand porosity values using the original Thomas-Stieber model. A data cloud of around 50% shale volume and 25% clean sand porosity will likely either under- or overestimate sand porosity based on the true volumes of dispersed and structural shale present in the reservoir. This work establishes the need for differing clay properties.

In addition to exhibiting both clean sand and shale lamina, a recently acquired data set was also shown to include significant volumes of both dispersed and structural shale. Analysis of this data set indicates that portions of the reservoir with larger volumes of grain-replacing structural shale can be differentiated from those bearing larger volumes of intergranular dispersed shale using acoustic data as the discriminant. We illustrate the relationship between varying volumes of dispersed and structural shale quantified using thin-section and SEM image analysis and laboratory and log-based acoustic properties. Because structural shales act to decrease the velocity, and dispersed shales act to increase it, analyzing massive sands with varying volumes of each type of shale using the gamma ray, density, and acoustic properties allows us to deconvolve their influence on the logging tool measurements. Optimizing this differentiator allows for a refinement of the clean sand porosity and shale volume estimates computed by the Thomas-Stieber model, which will improve saturation and permeability interpretations.

This work quantitatively demonstrates the different porosity and gamma ray attributes of structural clays from dispersed clays. Meanwhile, the porosities are similar (with the exception of glauconite (rare)). The gamma ray values also differ from the shale/clay laminations. This significantly changes the estimates of the volume fraction of the clay distributions. This new formulation of the Thomas-Stieber plot allows quantitative estimates of the three distributions to be determined.

Wireline Cable Dynamics and Wellbore Diagnostics in the Deepwater Logging Environment
Lee Hyson, Mike Hanson, Guy Wheater, Stuart Huyton, Scott Ballou, Xavier Perez, Alfonso Mendez Camarena, Luke Miller, Hamish Munro, and Ron Ford, Gaia Earth Group

The evolving complexity of deepwater wellbores has created new challenges and risks for wireline evaluation. Geometries and depths challenge the foundational assumptions of traditional depth control. As complexity grows, formation fluid gradients see scatter, sidewall cores have uncertainty about where they were taken, and mistakes have higher economic and environmental consequences.

This study presents empirical data sets obtained from cable-mounted memory sensor packages during deepwater openhole logging operations. This is the first-ever study of wireline dynamics using downhole cable-mounted sensors. The sensors record wellbore temperature, pressure, triaxial accelerometer, and magnetometer data. An independent record of all downhole events like tool movements, depths, speeds, survey intervals, cable torques, and sticking events allows evaluation of hole and mud conditions, cable dynamics, and tool response throughout the logging operation.

To date, cable-mounted sensors have been used to acquire data on 64 runs in 15 deepwater wells, covering a wide range of wireline services. These runs have particularly enhanced wireline formation testers and data quality control (QC). These data sets are contributing to new understandings of how depth control during wireline operations can be improved, but also provide practical wellsite data. One practical result of these studies is understanding downhole tool and cable movement compared to bulk creep corrections, as shown in Fig. 1.

Fig. 1—The cable-mounted sensor package allows comparison of tool/cable movement to bulk creep corrections.

Other practical results include the ability to confirm loss zones and to identify sticking or jarring events.

The cable-mounted sensors output depth-based logs that encompass pressure, temperature, synthetic mud weight, cable rotation, casing-collar locator (CCL), inclination, and road noise, leading to the following outcomes:

1. **Continuous Extrapolated Temperature Logs:** These logs allow us to clearly identify mud column heating and cooling zones, with observable rates of change across consecutive runs and static temperature estimates from different reservoir packages to 10 ft TVD resolution.

2. **Mud Column Integrity:** Variations in mud column integrity have been detected following sampling operations, including the identification of a leaking packer during an attempted mini-frac.

3. **Wireline Creep:** Computed from accelerometer measurements after the winch has stopped on the station, wireline creep offsets of up to + 5 ft shallow have been identified. Anti-creep has also been identified, whereby the tool slows then stops before reaching the station, by up to – 8 ft deep. Creep is shown to be highly variable and may be the tip of a depth-discrepancy iceberg, driving scatter on fluid gradient plots.

4. **Station Log Validation:** Via continuous accelerometer data acquired during the entire pretest or rotary coring surveys, the winch technique and depth control can be validated (and improved if necessary). In deep, tortuous wells with high-viscosity muds, large and long tool strings may become decoupled from winch movements at surface, resulting in major depth errors. A traffic light system for station log depth quality has been established to drive logging procedures on a case-by-case basis.

5. **Cable Dynamics:** During incidents involving stuck tools, the sensors have been instrumental in confirming cable freedom, and they have recorded jar firing (or failure), providing valuable insights.

6. **Torque Logs:** These logs offer a downhole record of tension, torque, and rotation count during wireline operations. They supplement shop records and contribute to optimizing cable maintenance and inspection regimes.

7. **Road Noise Logs:** These logs identify cable contact zones, which may be used to assess wireline casing wear zones before they happen.

As we continue to better understand and utilize these data sets, we can anticipate practical and academic improvements that will enhance wireline formation evaluation and benefit the industry.

NEW TECHNOLOGIES / APPLICATIONS

A Benchmark Well-Logging Database From Brazilian Terrestrial Basins

Rodrigo César Teixeira de Gouvêa and Cleyton de Carvalho Carneiro, University of São Paulo

A comprehensive, well-structured, and diverse benchmark database of well logs is crucial in advancing data science tasks in geoscience studies. Such a resource serves as the foundation for the use of machine-learning techniques in various critical endeavors, including geological modeling, reservoir characterization, and resource exploration. In this sense, in 2021, the Brazilian National Agency for Petroleum, Natural Gas, and Biofuels (ANP) made available, free of charge, a database of drilling activities in Brazilian continental sedimentary basins. However, the agency's database exploration tools have limited resources for well and profile information retrieval. Compiling and structuring this database to create an informational environment for dynamic and exploratory interactions could enhance productivity in terms of queries and data extraction. Easy access to the data and metadata would facilitate their use in various desired applications, whether for analysis, queries, or visualization. Therefore, the primary objective of this work is to create a well-structured and preprocessed benchmark database of well logs from the major terrestrial basins in Brazil that is freely available for the development of data science tasks.

The process of creating this benchmark database employed data mining techniques to establish a metadata repository for each of the wells within the ANP database that possessed DLIS file types. Subsequently, a JSON (JavaScript Object Notation) file was generated containing well metadata such as basin name, well code, file name, presence of AGP file, number of frames in the file, depth index type, maximum and minimum depths, acquisition spacing, number of channels, channel mnemonics, their description, and unit. This resulted in a metadata repository of 21,303 wells. This repository was then utilized in a data mining workflow to select the wells that would constitute the benchmark data set. In this workflow, all depth units were converted to meters, including "0.1," "0.1 in.," "0.5 mm," "M," "ft," "in.," "m," and "mm." Wells with depths ranging from 100 to 2,000 m were selected. Among the selected wells, the longest run with the highest number of channels (mnemonics) was chosen, resulting in a data set of 5,065 wells. Cataloging of mnemonics in this data set was performed, followed by their classification into profile groups: gamma ray, neutron porosity, density, photoelectric factor, compressional wave, spontaneous potential, caliper, and bit size. These wells were then plotted on a map, with 20 wells selected from each of the following Brazilian terrestrial basins: Alagoas, Espírito Santo, Parnaíba, Potiguar, Recôncavo, Sergipe, and Solimôes. This selection process was carried out based on the following criteria: (i) wells with the highest count of selected profile groups; (ii) proximity of wells, ensuring some lateral overlap; (iii) selection of distant wells for comparison; (iv) selection of wells from different production fields and exploratory blocks; (v) selection of wells with occurrences of oil/natural gas. This process resulted in a data set of 140 wells with depths ranging from 126 to 1,872 m, featuring lithostratigraphic overlap, control wells, and extensive spatial distribution.

This database underwent preprocessing to standardize the units of variables: gamma ray (GAPI), neutron porosity (p.u.), density (G/CC), photoelectric factor (b/e), compressional wave (uspf), and spontaneous potential (mV). Outliers in the variables were corrected, and anomalous values of the differential caliper and bit size values exceeding 12.5 in. were removed. Lastly, the gamma ray and spontaneous potential variables had their histogram distributions adjusted relative to the regional median (for each basin) to achieve uniformity. The result is a well-logging database suitable for machine-learning tasks, which will be employed in the evaluation of well-similarity methods and measures, as well as assessing sample representativeness and database creation in data science tasks based on well-logging information.

A Novel Approach to Estimate TOC in Unconventional Reservoirs: The Case of the Pimenteiras Shale, Parnaíba Basin, Brazil

Luis Miguel Rojas, Lilian S. Silveira, Frederico Miranda, and Jose Roberto Correa, ENEVA S.A.

The Devonian Pimenteiras Formation, nestled within the resource-rich Parnaíba Basin in Brazil, is continuously under evaluation as a compelling unconventional reservoir. Shale gas, interbedded gas, and tight gas accumulations are recognized within the formation but have not been commercially produced so far (Miranda, 2014; Miranda et al., 2018). This abstract presents a pioneering approach to the comprehensive characterization of total organic carbon (TOC) in the Pimenteiras Shale, featuring techniques like core-log integration and multilinear regressions, which are particularly valuable for overcoming the challenges posed by the lack of advanced logs and log quality issues. Resistivity logs are often affected by either high pyrite, conductive minerals, and others, challenging petrophysicists to perform an accurate TOC estimation through the most used methods, such as Delta-log R. Other methods require either additional calibrations for control variables or require advanced logs, such as nuclear magnetic resonance (NMR) and nuclear spectroscopy.

Seven wells were selected with TOC analysis of sidewall cores and cuttings samples collected from the Pimenteiras Shale, significantly enhancing the approach of core-log integration. This technique combines traditional core measurements with available downhole log data to provide a more comprehensive understanding of the reservoir's TOC quantification. The core-log data integration compensates for the limitations of the absence of advanced logs and augments the accuracy of calculations. In response to the challenge of limited log data quality, multilinear regressions are employed. These regressions allow for the development of predictive models that leverage the available data to estimate crucial reservoir properties. By quantifying the relationships between core-derived data, geological observations, and the limited log data, multilinear regressions offer valuable insights into reservoir behavior, mitigating the impact of log quality issues.

In conclusion, this research highlights a groundbreaking approach to characterizing the TOC of the Pimenteiras Shale in the Paranaiba Basin, Brazil. By integrating core-log data and employing multilinear regressions to address the lack of advanced logs and log quality issues, we aim to provide a comprehensive understanding of this unconventional reservoir. The result from the new approach achieved an average $R^2 = 0.77$ between measured and calculated values in the studied wells, demonstrating an added value to the subsurface integration. This research is pivotal to unlocking the full potential of the Pimenteiras Shale, contributing to Brazil's energy security, regional development, and sustainable hydrocarbon production.

An Automated Workflow to Optimize Parameters for Formation Pressure Measurements Utilizing Memoization

Pontus Loviken, Yon Blanco, and Tianjun Hou, SLB

Pore pressure measurements are essential over the life of an oil field, providing critical information from exploration through development. However, designing pressure tests with a formation tester (either on wireline or logging while drilling (LWD)) might not be straightforward as it requires understanding several variables such as overbalance, permeability (both horizontal and vertical), viscosity, porosity, compressibility, etc. Modeling software exists to predict the behavior of a pressure response under multiple combinations of those variables. Typically, trial and error are used to adjust the best pressure test parameters, which are drawdown volume, drawdown rate, and buildup time. The goal is to optimize volume, rate, and time in such a way that a fully stabilized pressure measurement is obtained in the minimum time possible. In practice, this is difficult since each test has to be evaluated over many different variable combinations one expects to encounter. In this work, we develop a method to automate this process to suggest optimal pressure test parameters, given the expected distributions of the key variables. This optimization includes a tradeoff between the probability a given test would work for a random variable combination and the time each test takes, which is left to the user to decide. Additionally, the user can generate multiple pressure tests, where each is optimized to solve the scenarios that the previous test failed to solve.

In this work, we are treating each pressure measurement as two individual tests: an initial drawdown followed by a pressure stabilization time, followed by a second drawdown and a second stabilization time. As each drawdown is defined by a volume and a rate, each full test consists of six parameters. Given expected distributions over the key formation variables, expressed in terms of P10, P50, and P90 values, the goal is to instantly know in what proportion of all scenarios a given test configuration will work. This is done using memoization. A data set of 1,000 scenarios is generated ahead of time using the given distributions. In each of these scenarios, the pressure responses of different drawdown volumes and rates are simulated and subsequently registered using modeling software. By using the fact that the result of the second test depends on the stabilization pressure of the first, it is possible to disentangle the second test from the first by always stopping the first test at a given pressure within a predefined range. This reduces the combinatorial complexity significantly, as the two tests can be analyzed independently. During optimization, it is thus possible, without further use of the modeling software, to instantly know for what scenarios a given test configuration will work, allowing for rapid configuration search and providing the best solution for each total test time. The process can be repeated with unsolved scenarios to build a toolbox of different tests for the different scenarios.

The proposed method is rapid and flexible at testing time and leaves much room for the user to influence the optimization process, focusing on certain parts of the variable space or optimizing with respect to what is unsolved by previous tests. The time-consuming step is the one-time cost of memoization, which for 1,000 scenarios takes around 48 hours on a standard laptop for 100 volume-rate combos for each drawdown, giving 10,000 possible test configurations to search among. Once done, pressure test parameters can be instantly evaluated over all scenarios, and optimization for all test parameter combos can be made in less than a minute. Preliminary analysis confirms that the tests suggested by the method work well in simulation and outperform both the standard tests as well as hand-crafted tests by domain experts.

An Image-Based Artificial Intelligence Approach for the Determination of Analog Petrophysical Rock Properties From Drill Cuttings

Allen W. Britton, Core Laboratories; Shouxiang (Mark) Ma, Saudi Aramco; Katrina Cox, Core Laboratories

A thin-section image-based artificial intelligence (AI) model, leveraging an associated database of 100 conventional core samples, has been developed, validated, and published for the determination of analog petrophysical properties when conventional core is unavailable. The AI model, with newly available data, continues to be updated, resulting in an ongoing learning process. In this study, we will focus on applying this technology to synthetic drill cuttings and present gained insight into additional factors that may also impact the AI-based analog drill cuttings results.

A subset of 20 samples, consisting of multiple lithologies of conventional core-based synthetic cuttings, were evaluated in three size classes of 5, 4, and down to 2 mm (60 samples total) in order to compare analog petrophysical properties (porosity, permeability, matrix density, mineralogy, electrical properties, and capillary pressure) to their physically measured properties. This was accomplished in the following steps: (1) Each synthetic cutting sample to be evaluated was created by disaggregating a conventional core plug, whose data was used in the creation of the AI model and sieving the results into the three size classes noted above. (2) A thin section was then prepared for each of the sample's three size classes. (3) The thin sections were subsequently scanned in high resolution (0.44 µm/pixel). (4) Each scanned image was submitted to the AI model for analysis, and the petrophysical data sets associated with each AI-based analog match were returned from the database for evaluation and comparison to the physically measured core data.

Results of the AI analysis indicate that lithology plays a major role in the analog synthetic cuttings results. Analog petrophysical properties of the clastic synthetic cuttings (comprised of sandstone, siltstone, organic argillaceous sandstone, argillaceous sandy siltstone, argillaceous sandstone, and argillaceous dolomitic sandstone lithologies) reasonably matched the physically measured properties at a frequency of 85%, while the carbonate synthetic cuttings (comprised of limestone, dolostone, dolomitic limestone, celestine dolostone, calcareous dolostone, and bituminous dolostone lithologies) only matched at a low frequency of 38%. Analysis of the three size fractions—5, 4, and 2 mm—found that the size of the cuttings, and thus the amount of sample heterogeneity (or variability in pore geometry) available for analysis by the AI model, was less of an influencing factor in the results. This finding reflects well on the resolution (0.44 µm/pixel) of the thin-section images used in the model, though analysis of cuttings less than 2 mm in size needs to be further evaluated to find the effective lower limit on the effect of size. All the above observations are being evaluated further, including the potential loss of heterogeneity during the process of creating cutting samples.

Assessing Well Integrity and Water Injection Performance in Selective Completions With Injection Logs and Distributed Temperature Surveys

Cristian Escarraga, SLB; Alejandro Castaneda and Zhully Ortiz, Ecopetrol; Marcia Benavides, Andrea Ordonez, and Diego Garcia, SLB

The fields discussed in this technical success case are neighboring mature heavy oil producers currently under water injection through selective completions of a tubing equipped with downhole injection mandrels and valves designed to allow water to enter with a specific pressure and rate to maximize reservoir fluids displacement in an environment of highly variable pressure and petrophysical properties between layers with several perforations isolated by groups, with packers. In these fields, it is very well known that oil recovery is more efficient in selective completions than in commingled injection since downhole-to-reservoir pressure management is more effective; however, once the completion is deployed and operative, it is difficult to assess and evaluate the injection distribution at perforations along the different injection groups, locking the surveillance of real water injection per perforated foot and veils possible events such as formation damage, fractures, or well integrity issues behind tubing.

Traditionally, downhole injection rates are measured with conventional production logging tools or radioactive tracer flowmeters, but the injection rate behind tubing is not characterized. The temperature warm-back effect is described as the trend that formations have to return to their original temperature (geothermal) after inducing a thermal disturb; for example, after injecting colder water compared to geothermal, the formation cools and starts warming gradually, and its velocity depends on water amount and rock properties. This physical principle, combined with a precise measurement of downhole rate with injection logging tools (ILT), is the core to deploy an exhaustive assessment of water injection performance and well integrity, but measuring temperature to satisfy this objective needs a careful design with an innovative technique that distributed temperature surveys (DTS) with fiber optics can completely offer, as delivers continuous temperature measurement along the well during the necessary time. To add value to the injection operation, the downhole survey needs to be agile; therefore, a logging truck with an interchangeable cable drum that allows the acquisition of ILT and DTS in a tight timeframe was deployed to reduce operative costs and time. Workover engineering teams in the operator company initially select wells with concerning behaviors such as irregular rate and pressure or integrity events occurring. The operational design starts with an ILT log survey with well injecting to compute the downhole individual rate per valve. Then, the tool is pulled out of the hole, the well is shut in, and the logging cable is replaced by fiber optics while the well stabilizes. The DTS is deployed to total depth (TD) for 2 hours with the well shut in, then 4 hours flowing, and ends with 12 hours shut in for the warm-back evaluation.

In the last year, this technique has been deployed in 15 water injection wells, where observations of downhole rate plus warm-back effect have allowed the confirmation of the injection pattern at perforations in different groups behind tubing, unlocking events of preferential flow (possible induced fractures), crossflow, and integrity compromises at packers and cement. Also, due to the revealing result obtained in the injectors, the warm-back technique with DTS has been deployed in two producers with the challenging but achieved objective of identifying very small leaks. The field's management has approved this technique for standard water injection performance and integrity surveillance since it has allowed the optimization of valves' design and overall injection, and the service company has standardized this technique with a specialized multidisciplinary team that works in synergy with the operator, which way forward is to expand it to other fields.

Automated Identification of LRLC Reservoirs Using Regression Machine Learning in South Sumatra Basin, Indonesia

Aziz Permana, Yan Gustian, Jerry D. Mamesah, Pambudi Suseno, Giyatno, and Djudjuwanto, Pertamina Hulu Rokan; Diah A. Rahmalia, Sudarmaji, and Sarju Winardi, Universitas Gadjah Mada

The South Sumatra Basin has played a pivotal role in Indonesia's oil and gas production for several decades. This study focuses on evaluating the potential of the Muara Enim, Air Benakat, and Gumai Formations, situated above the primary Baturaja carbonate and Talang Akar sand reservoirs. While 27 wells have demonstrated hydrocarbon production from the low-resistivity low-contrast (LRLC) reservoir, approximately 85% of the staggering 4,700 operational oil wells are currently suspended. The identification of LRLC pay zones is a daunting challenge due to the voluminous data set and repetitive nature of the task.

The classification machine-learning algorithm was used in an exploration well (Well HBS-001) to automate the hydrocarbon prospecting process for LRLC reservoirs. Initially, data inputs were classified based on well data completeness, with particular emphasis on parameters such as Vshale (VSH), porosity (PHIE), total porosity (PHIT), water resistivity (R_w), and true resistivity (R_t). Subsequently, net reservoir and non-reservoir zones were determined using VSH and PHIT cutoff values. The third step involved distinguishing pay zones from water zones utilizing R_t-R_o log separation and RHOB-R_t log separation, with a crucial parameter being the R_t and R_o ratio. A ratio greater than 1 indicated a pessimistic result, while a ratio greater than 1.2 indicated an optimistic result. Following this, the fourth step was the identification of LRLC reservoirs, defined by a resistivity value of under 5 Ω. These LRLC reservoirs were further categorized into three groups based on oil production data tests: proven LRLC (with favorable parameter values), prospective LRLC (lacking data tests but possessing favorable parameters), and potential LRLC (with incomplete parameters and no data tests). The final step involved training the data using classification machine-learning models, specifically support vector machine (SVM), XGBoost, random forest, and artificial neural network (ANN).

The results indicate a favorable fit between the training data set and the production test results, with a need for further validation of water resistivity (R_w) values. The SVM yielded an accuracy of 0.92 and F1 of 0.91, XGBoost had an accuracy of 0.99 and F1 of 0.99, random forest showed an accuracy of 0.99 and F1 of 0.99, while ANN demonstrated an accuracy of 0.97 and F1 of 0.97. The random forest and XGBoost models presented in this study offer an automated and expedited approach for selecting potential LRLC reservoirs with significant hydrocarbon content. This innovative approach not only streamlines the identification process but also holds promise for accelerating the exploitation of the South Sumatra Basin's valuable resources.

Core Scanner for Electrical Profiling of Full-Bore Cores at the Wellsite With Advanced Pulse Electromagnetic Technology

Dler Mirza and Kristofer Birkeland, Aker BP; Lars Øy, Roland Chemali, and Benjamin Barrouillet, WELL ID

When freshly cut full-bore cores come up to the rig floor, petrophysicists are eager to know whether or not they have hit their objective. Should they continue to core ahead? Or should they stop coring and proceed with the drilling operation toward their next objective? Where are they on the structure when correlating to other wells in the field? We present a new core scanner instrument that can answer these important questions while the core is on the rig floor. The new scanner measures the resistivity and the dielectric permittivity of the cross section of the core. The output is a finely resolved survey along the axis of the core. The observed resolution is on the order of 2 cm. Later, we integrate resistivity and dielectric permittivity measurements with other petrophysical parameters from the core analysis to refine the formation evaluation results. We combine the resistivity and dielectric permittivity with lithology, porosity, and water resistivity in the complex refractive index equation. The outcome is a finely resolved estimate of the water-filled porosity and water saturation.

The new core scanner device includes a transmitter antenna and a receiver antenna located on opposite sides of the core. The assembly moves along the axis of the core. The transmitter antenna emits pulsed microwave signals, similar to radar pulses, operating in the mid-GHz range. The pulses travel across the section of the core and reach the receiving antenna. Very fast electronics with advanced digitizing circuits convert the received signal into binary output. This enables us to apply sophisticated signal-processing techniques. The first level of output includes the amplitude of the received signal and the traveltime across the section of the core. Through joint inversion, we convert the amplitude and traveltime into resistivity and dielectric permittivity.

We have recently tested the new device on a series of full-bore cores from wells offshore Norway. Naturally the core barrels were nonmetallic to allow the electromagnetic microwaves through. The results showed good agreement between the resistivity from the core scanner instrument and the openhole logs, but with much finer resolution. In high-resistivity intervals, we observed, as expected, a difference due to resistivity frequency dispersion. At the other end of the scale, for formations below 1.5 Ω·m, the device in its present design lost the ability to provide accurate traveltime. In the formations of interest, however, where the resistivity range was 1.5 Ω·m and above, we obtained a robust inversion yielding reliable resistivity and dielectric permittivity. The joint interpretation of resistivity and permittivity yielded a correct water-filled porosity, in agreement with the classic openhole interpretation but with finer resolution.

Deep Insight Into Presalt Carbonates: Advanced AI Multi-Regression Technique for Depth-By-Depth Elastic Pore Geometry

Luciana Velasco Medani, Adna Grazielly Paz de Vasconcelos, Allan Peixoto de Franco, Gabriel Gonçalves Cardoso, Danilo Jotta Ariza Ferreira, and Giovanna da Fraga Carneiro, SLB

Although rock physics models are useful in understanding the impact of porosity on the mechanical properties of hydrocarbon reservoirs, the models are a simplified representation of porous media, especially for complex and heterogeneous presalt carbonate rocks. Furthermore, these models heavily rely on input parametrization, such as the elastic parameters of mineral and fluid constituents. With less dependence on model parametrization, machine-learning techniques are proven data-driven approaches for tackling inverse problems, especially for ill-posed, non-unique, and nonlinear geophysical inverse problems. Driven by this, we introduce a pioneering method for the automated assessment of pore shapes within presalt carbonate reservoirs at the well-log scale, which employs a multi-regressor supervised learning approach.

Automating this process circumvents the inherent limitations and subjectivity associated with rock physics inversion. The automation expedites the process and mitigates potential human biases that might influence the characterization. The result is a more objective and comprehensive understanding of the interplay between pore geometries and elastic behavior.

The multi-regressor supervised learning model has the potential to capture nuanced patterns and correlations hidden within the well-log data.

The proposed algorithm was designed to automatically estimate the pore geometry, in a depth-by-depth manner, representing a significant advance in reservoir elastic properties analysis. This machine-learning algorithm is combined with an automated rock physics inversion model to create a comprehensive and versatile framework for quantifying and predicting the volumetric fraction of three pore types (PT) geometries in the presalt carbonates. PT 1 is represented by crack-shaped pores. PT 2 is the dominant pore type and represents pores with an aspect ratio of 0.15. PT 3 represents round pores with an aspect ratio of 0.70.

The machine-learning algorithm employed in this approach is a random forest multi-regressor model capable of simultaneously predicting each PT volume fraction, considering the dependency between them and the features (logs) defined in the modeling step. The algorithm analyzes and interprets complex data sets with a high degree of accuracy. It can discern patterns, relationships, and anomalies within the data that might otherwise remain unnoticed through traditional analysis methods.

Complementing the machine-learning component, the automated rock physics inversion outputs are used as targets in training the supervised model, serving as a pivotal tool in translating seismic data into meaningful insights about subsurface properties.

This data-driven approach addresses the challenges posed by the intricate nature of presalt carbonates, where rock physics models often fail to accurately characterize complex and heterogeneous formations.

This innovative workflow was applied to a presalt well in the Santos Basin. The results from the machine-learning algorithm were validated by the rock physics inversion outputs for the well, and these were, in turn, validated against an extensive pore geometry characterization from thin-section analysis.

In this well, the volumetric fractions of pore types PT1, PT2, and PT 3 were predicted with a random forest multi-regressor model. The key features selected by the model were the compressional velocity, total porosity, and bulk density logs, with importance scores of 49, 34, and 17%, respectively.

When compared to the rock physics inversion outputs, the predictions for the volumetric fractions of pore types PT 1, PT 2, and PT 3 had errors of 3.7, 4.6, and 3.2%, respectively. This machine-learning strategy automates wellbore-scale pore characterization by adopting a fully data-driven approach and significantly reduces the subjectivity associated with rock physics model parametrization. Ongoing research is extending this methodology to other wells within the same oil field to prove the capability of model prediction within rocks with similar elastic characteristics. Additionally, we aim to enhance the model's robustness by evaluating which other petrophysical logs can be used as features.

Investigating the Impact of Ion Movement Dynamics in the Electrical Double Layer on Dielectric Permittivity Measurements

Zulkuf Azizoglu and Zoya Heidari, The University of Texas at Austin

Charged mineral surfaces create an electric field, which significantly affects electromagnetic measurements in porous media. This field is partly balanced by the electrical double layer (EDL), a charge structure that forms adjacent to the grain surface. EDL is influenced by the ionic strength of the electrolytic solution. Therefore, one of the most important properties that influences the low-frequency polarization behavior (i.e., below 20 MHz) is the salt concentration. Additionally, ion type significantly affects the EDL polarization because of the changes in the ionic transport properties (i.e., mobility and diffusivity of the ions). Therefore, it is important to fundamentally understand and separate the impacts of salt concentration, salt type, and pore geometry on dielectric permittivity at low frequencies. This can be accomplished via frequency- and/or time-domain dielectric permittivity simulations. However, the frequency-domain solvers require additional rock physics models to quantify the EDL polarization. Meanwhile, the time-domain dielectric permittivity simulations, where the ionic movement is directly modeled, present an ideal framework for investigating the ionic transport dynamics in the vicinity of the EDL. However, reliably defining the ionic transport properties near EDL is critical in the time-domain simulations, and there is a lack of understanding about the influence of those properties on the effective dielectric permittivity of the fluid-saturated rocks. Therefore, the objectives of this paper are to (a) investigate the influence of ionic properties on the dielectric permittivity in a wide range of frequencies, (b) investigate the possibility of coupling molecular dynamics simulations (MDS) with the time-domain solver to characterize the ion movement near EDL reliably, and (c) investigate the sensitivity of dielectric permittivity to salt concentration, type, and pore geometry.

We use our recently developed time-domain dielectric permittivity simulator to estimate dielectric permittivity in spherical grains and 3D pore-scale rock samples. The simulator simultaneously solves the Maxwell and Nernst-Plank equations in the time domain. We apply a Gaussian source to the rock model and capture the sample's response to the excitation. The outcomes of the simulations are the distribution of ions and electric potential. Finally, we use Fourier transforms to obtain the complex dielectric permittivity in the frequency range of 100 Hz to 1 MHz. To fundamentally define the mobility and diffusivity of the ions near the EDL region, we perform MDS. We estimate the diffusivity of the ions in the brine-grain interface via the mean-square displacement method. The ionic mobility is calculated from the diffusivity using the Einstein-Smoluchowski equation. We investigate the sensitivity of dielectric permittivity to salt concentration (1 to 100 kPPM), salt type (NaCl, KCl, and $CaCO_3$), ionic mobility and diffusivity, and the ionic properties in the vicinity of the EDL region.

We observed up to a 20% relative difference in the relative permittivity of the rock samples saturated with different salts, suggesting that ion type should not be neglected in interpreting the dielectric permittivity. Results indicated that the diffusivity and mobility of the ions significantly impact the relative permittivity dispersion. However, the changes in the diffusivity did not influence the electrical conductivity. In contrast, changes in ionic mobility linearly affected the electrical conductivity of the sample. We observed that the ionic properties defined for the EDL significantly influenced the relative permittivity. This indicates that the mobility and diffusivity of the ions in the EDL need to be carefully defined for reliable modeling and interpretation of the low-frequency dielectric permittivity. Coupling dielectric permittivity simulations by molecular dynamics simulations was proven to be necessary for fundamentally understanding the mechanisms controlling the low-frequency dielectric permittivity behavior. The outcomes of this paper can potentially contribute to the enhancement of multifrequency complex dielectric response for simultaneous assessment of multiple petrophysical properties.

Lateral Geosteering Using Multidimensional Inversion Helps in Unlocking Reservoir Reserves in Complex Geological Environment

Mauro Viandante, Janine Maalouf, and Valeria Vergani, SLB; Michael Rabinovich, BP America, Inc.; James Davidson, Luke Magarinos, Kelsey Lovell, and Zakaria A. Hassan, BP Exploration Operating

A common challenge while drilling a horizontal well is to keep it placed inside the sweet spot to reduce drilling risk and optimize the production of the well, for example, placing the well at the desired standoff from the OWC and the top reservoir. The well is planned according to the best geological model, built using the available offset wells and surface seismic interpretation, in a geological zone believed to be structurally safe from major faulting and changes in formation dip.

However, while developing a brownfield, the aim is to increase the reservoir exposure and capture bypassed oil, for example, in areas close to or along a fault where we have an increase of both geological and drilling risks.

The geological and drilling risks are accentuated by intrinsic uncertainties related to the accuracy of both the seismic and surveying system spatial representation, both in the vertical and lateral plane. Thus, even with the most accurate predrill geological model, drilling a safe geometric well requires its placement hundreds of feet away from prognosed faults.

Previous generations of ultradeep azimuthal resistivity (UDAR) logging-while-drilling (LWD) technologies were only able to provide information regarding resistivity contrast associated with lithological or fluid properties changes along the drilling direction with no capabilities to map lateral resistivity changes associated with structural features such as a fault.

To optimize the placement of the well in a complex geological environment, where seismic analysis shows potential faulting, the new generation of three-dimensional (3D) UDAR reservoir mapping, which provides real-time 3D volumetric interpretation using one-dimensional (1D) longitudinal and two-dimensional (2D) transverse resistivity inversions was deployed.

The 3D UDAR service has a modular design with one transmitter and multiple receivers placed along the bottomhole assembly (BHA) and spaced between the other logging-while-drilling (LWD) or measuring-while-drilling (MWD) tools.

The transmitter and receivers' tilted antennas provide a full directional and 3D characterization of the resistivity tensor acquired; at each transmitter-receiver spacing's six operating frequencies with sensitivity, a broad range of formation resistivity profiles are also recorded. With 3D UDAR, the full 360° electromagnetic tensor is acquired and transmitted in real time using a new data compression algorithm and inverted with both 1D longitudinal deterministic and 2D transverse pixel-based resistivity inversions. The results are then converted into 3D resistivity volumes, providing a full multidimensional representation of reservoir boundaries and features.

Geological targets are multidimensional bodies with properties potentially changing in all three directions. While deploying any UDAR service, it is crucial to understand how the resistivity properties are changing not only spatially but also with respect to the depth of detection (DOD) of the electromagnetic resistivity wave.

Geological features at the scale of the UDAR measurements could be approximated and solved using 1D longitudinal inversions or higher-grade multidimensional inversions (i.e., 2D transverse inversions).

However, as in this case study, for reservoirs with more complex geology, the 1D inversion algorithms may not resolve the structural features surrounding the UDAR systems; therefore, the introduction of the 3D UDAR service with its recent advances in computing power unlocked the implementation of more complex inversion workflows that provides real-time 3D reservoir mapping based on 2D transverse resistivity inversions.

Teamwork between the operator and service company allowed the project to move forward from conventional geosteering techniques using previous UDAR technology, where steering decisions were based on 1D resistivity inversions. With the introduction of multidimensional inversion, 3D reservoir steering was performed in real time to azimuthally geosteer the well respect an approaching fault within the dogleg limits to optimize completion.

This case study will show how the 3D UDAR service enabled the strategic geosteering of the well in a complex geological environment, unlocking oil reserves.

Maximizing Look-Ahead Sensitivity to Presalt Reservoir in a Near-Vertical Scenario in the Presence of Intra-Salt Intercalations: A Case Study in Bacalhao Field, Offshore Brazil
Armando Vianna, Enrico Ferreira, Sergey Martakov, and Warren Fernades, Baker Hughes; Katharine Sandler Klein, Equinor

Presalt reservoirs represent a significant portion of the world's oil volumes, largely in Brazil and West Africa but also in the Gulf of Mexico, Norway, and the Caspian Sea. Exploration and development of presalt reservoirs represent a substantial challenge due to their complex geological characteristics and depth uncertainty. Traditional seismic inversion methods often struggle to provide accurate representations of these reservoirs due to factors like strong velocity inversions and limited resolution. In response, we introduce a robust look-ahead inversion workflow that leverages the full potential of ultradeep resistivity (UDAR) data in real time. The main objective of the geostopping application is to reliably determine the base of the salt with the major challenge of distinguishing intra-salt intercalations. Advanced detection of both the intercalations and the top of the presalt provides significant risk mitigation of potential well control hazards.

For look-ahead applications, the UDAR system is run with the receiver sub placed 7 m from the bit to maximize sensitivity to remote subsurface layers. This configuration has significant benefits in high-resistivity environments and look-ahead applications specifically because the relative measurements between the two receivers on the same sub naturally compensate for temperature fluctuations and any inhomogeneities around the transmitter.

The approach combines advanced look-ahead inversion with the maximization of depth of detection utilizing raw measurements from a UDAR tool featuring a three-coil array. The inversion workflow is configured to focus on the objectives of presalt geostopping. Selection of deepest-sensing measurements, noise-based stopping criteria, and extensive scanning of the most probable model domain—all these inversion inputs are adjustable during real-time processing if needed.

In addition, we introduce a concept of maximizing boundary sensitivity through the combination of several elements:

- Dynamic noise estimation and adjustment of the measured signal level (to compensate for precise calibration challenges in very high-resistivity environments is extremely challenging
- Analysis of curves' behavior and curve separation patterns
- Monitoring the signal level increase above observed noise levels according to a criterion defining the degree of certainty in boundary detection

After the first indication of the approaching inhomogeneity, we determine if the change in the signal corresponds to base salt or to an intra-salt intercalation. This differentiation can be done with the observation of curve behavior or by analysis of the inversion results. When measured signals are significantly above the noise level, confidence analysis is performed to confirm the reliable position of the approaching boundary, and the inversion workflow is configured to resolve the reservoir resistivity profile. In addition, the mapped structure is displayed in an interactive 3D viewer to aid asset decisions on geostopping objectives.

This innovative approach enhances confidence and reduces risk in accurately identifying the underlying boundary position and improves the accuracy of inversion results, leading to a better understanding of reservoir architecture ahead of the bit. This approach achieved first sensitivity to remote subsurface layers (more than 55 m TVD) and reliable detection of the salt base (30 to 40 m TVD ahead of the bit), ensuring successful geostopping at the optimal distance. The case study presented from the Bacalhao Field demonstrates and confirms the theoretical depth of detection. A combination of low-noise relative measurements of the three-coil UDAR tool and configurable look-ahead inversion workflows with subsequent quality control (QC) and confidence analysis addresses the unique challenges posed by the complex formations in a presalt environment and offers valuable insights for proactive geostopping in real time. As the presalt plays continue to be a focal point in the energy industry, this methodology holds the potential to significantly impact the success and efficiency of exploration and production efforts.

Maximizing Mudlogging Data Value: S_w and Porosity Prediction for the Cabeças Formation – Parnaíba Basin, Brazil

Vitoria Flores, Henrique Padoves, Marcia Nunes, Gustavo Pimentel, and Frederico S. De Miranda, ENEVA

The quantitative interpretation of mudlogging and gas data is still challenging due to the uncertainties associated with data acquisition and the lack of data quality control. Nonetheless, Beda and Tiwary (2011) have developed a method that provides quantification of reservoir quality and water saturation (S_w) using gas and mudlogging data.

The approach used in this work is based on the Beda and Tiwary equation (B&T), a technique employed to estimate water saturation while drilling. This equation bears similarities to the known Archie equation, which also determines water saturation using resistivity and porosity as input parameters. However, the B&T equation includes normalized gas data (methane) and perforability index (PI) as inputs for predicting water saturation. Another factor, the gas-water baseline (GW), serves as a reference for 100% water saturation. This corresponds to the normalized gas count over a water-saturated zone and can be compared to R_o (100% water-saturated reservoir resistivity) in the Archie formula (Archie, 1942) or the baseline in a Pickett plot (Pickett, 1973). The primary modification in this methodology lies in the adjustment of the PI equation to accommodate PDC drill bits commonly used in the studied wells. The number of bit nozzles affects the bits' pressure; hence, the formula needs to be adjusted to overcome this effect. Additionally, the control of the rate of penetration (ROP) was included to enhance chromatography quality control. In terms of porosity assessment, this methodology involves two steps: normalizing ROP by normalized C1 and, subsequently, calculating the perforability index (PI). The porosity will be estimated by using the regression formula derived from crossplot PI × PHIT (correlation well).

The Cabeças Formation, in the studied well (Fig. 1), located in the Parnaíba Basin, Brazil, has gas-bearing sandstone and heterolithic reservoirs deposited in a deltaic environment under tidal influence. The facies associations of this formation include channel-filling sandstones and tidal bars. The comparison of water saturation (S_w) values between the proposed method and the petrophysical analysis using the traditional Archie equation (a = 1, m = n = 2) resulted in an R^2 of 0.81, and for porosity compared to gas-corrected density neutron, an R^2 of 0.63 was obtained. The results were used to support the definition of the gas-water contact (GWC), confirmed with pressure data and petrophysical evaluation. Although a lower R^2 was obtained for the porosity, the average values are quite similar. The trend and magnitude of the predicted porosity are well aligned with the porosity derived from log data. In conclusion, this methodology finds applications in predicting both water saturation (S_w) and total porosity (PHIT) before conducting wireline log measurements and, by doing so, adding value to the already existing mudlogging data by performing an early formation evaluation. This can support decision making and avoid a lack of information in case of operational restriction for a later wireline log operation.

Molecular Dynamic Simulation of CO_2 Flooding Into Mineral Nanopores in the Presence of Residual Oil

Isa Silveira de Araujo, Ibrahim Gumma, and Zoya Heidari, The University of Texas at Austin

Greenfield residual oil zones (ROZ) are considerably thick columns of oil at residual or near-residual oil saturation. In these zones, oil can only be recovered through the application of unconventional methods. Therefore, greenfield ROZ has emerged as an attractive target for enhanced oil recovery (EOR) by CO_2 flooding. The geochemistry of the solid surface, reservoir conditions, as well as oil composition are parameters known for having a significant impact on the wettability of the rock to reservoir fluids. Although extensive research has been dedicated to studying EOR by CO_2 flooding, the impacts of the aforementioned factor on CO_2 flooding efficiency are still not clear. In this work, we use molecular dynamics (MD) simulations to investigate, at an atomistic scale, how the effectiveness of oil recovery is affected by (i) the geochemistry of different mineral types, (ii) temperature, and (iii) oil composition.

In this work, we investigate interfacial interactions of systems composed of CO_2/oil/water/minerals. The minerals included in this work are illite, kaolinite, and calcite. Oil phases of different compositions are analyzed. First, we evaluate an oil phase composed of only decane molecules. Subsequently, sodium decanoate molecules are mixed with decane molecules to represent an oil phase of different compositions. To represent a mineral nanopore at residual oil conditions, the surface of these minerals was randomly dispersed with the organic components. Then, MD simulations were performed to allow the organic molecules to equilibrate at the mineral surface. Finally, the system was flooded with CO_2, and MD simulations were performed again. To investigate the effects of temperature on the CO_2/oil/mineral interactions, simulations were performed at 350, 375, and 400 K. From the outputs of the simulations, density profiles and diffusion coefficients of the investigated molecules were quantified.

Results indicated a higher decane adsorption on calcite surfaces compared to illite and kaolinite. We also observed that decanoate anions do not adsorb to the kaolinite silicate surface. Instead, they tend to interact with the hydroxyl surface. The results of the simulations performed on systems containing illite and sodium decanoate molecules suggested that these molecules will remain adsorbed to a clay surface when a bridging cation is present. When carbon dioxide was flooded into the mineral nanopores at a temperature of 350 K, a few oil molecules diffused into the bulk solution. An increase in temperature to 375 K and subsequently to 400 K led to an increase in the detachment of more oil molecules from the mineral into the bulk carbon dioxide solution. The outcomes of this work elucidate the CO_2/oil/rock interfacial interactions and clarify the effects of oil composition, temperature, and mineral type on these interactions. Moreover, the results presented here have a direct contribution to the improvement of the efficiency of the displacement process of oil by CO_2 injection in residual oil zones.

New Experimental Method for Enhanced and Fast Saturation of Tight Rock Samples

Sabyasachi Dash and Zoya Heidari, The University of Texas at Austin

A reliable and fast core saturation process forms the basis for many saturation-dependent measurements of petrophysical properties, such as relative permeability and capillary pressure. Conventional laboratory-based methods for saturating tight core samples take significant time, making the process expensive and not feasible. The conventional experimental setups used in the laboratory require high backpressure systems, which mandates additional safety features to be built, adding to the complexity of the setup. Such methods can lead to multiple months of experiments, including the saturation process and the permeability measurements, for measuring a single relative permeability data point. A high-speed centrifuge is another option used for saturating core samples, but it leads to a non-uniform saturation profile along the length of the core sample. In this paper, we introduce a new method that enables fast saturation of tight core samples while maintaining a uniform water distribution along the length of the core samples.

The experimental fixture and procedure described in this paper are primarily intended for saturating tight core samples but can also be used for conventional core samples. We start with a core sample cell of 1.5-in. diameter with a movable piston with three O-ring grooves on the outer surface of the piston. The piston is moved into the sample cell chamber with the help of a syringe pump, separating the chamber into lower and upper parts. The lower part contains the core sample sitting in the saturating fluid isolated from the upper part, where the injection fluid from the syringe pump pushes the piston into the chamber. The saturating fluid used in our study is 3 wt% KCl brine solution to reduce the impact of clay swelling during the saturation process. We used cylindrical core samples as well as altered core samples, with a cavity of 0.5-in. diameter at the center, for the saturation process. The core samples were subjected to a pressure of 1,500 psi using the syringe pump-piston setup. We performed NMR T_2 measurements before and after the saturation process to monitor the total water saturation. We also performed NMR saturation-profile measurements to confirm the uniformity of the water saturation along the length of the core sample.

We tested the aforementioned workflows, including the new tool and the altered core sample on outcrop samples from the Eagle Ford Formation. We cut the cylindrical core into two equivalent parts, Sample 1 and Sample 2. We modified the Sample 2 into a hollowed-out cylindrical shape. The absolute increase in bulk water volume for Sample 1 (intact sample) was 1.4% compared to 1.66% for the case of Sample 2 (hollowed sample). The initial saturation level for the case of Sample 1 was higher compared to Sample 2. The initial saturation was measured using NMR after heating the samples at 45°C for one day. The increased exposed surface area for Sample 2 allowed the heating process to dry the sample effectively. The measured NMR saturation profile was uniform due to the uniformity of the exposed surface to the saturating brine. The uniform saturation profile is advantageous when we perform saturation-dependent measurements on the core sample, such as capillary pressure, relative permeability, and electrical measurements. Saturating tight core samples took 3 days using the new tool compared to approximately 25 days using the conventional coreflooding technique. The novelties of this method for saturating tight rock samples include (a) significantly shorter times compared to conventional methods, (b) less expensive and specialized equipment compared to conventional methods such as ultrahigh-speed centrifuge, (c) relatively uniform water saturation profile, and (d) minimal impact on petrophysical properties of core samples during the saturation process compared to methods such as centrifuge.

Pseudo-Borehole Images From Outcrop Photographs: Improving Geological Interpretations
Sofia Alves Fornero, Petrobras and Federal University of Rio Grande do Sul; Candida Menezes de Jesus, Pamella Paiva Fernandes, and Willian Andrighetto Trevizan, Petrobras

The interpretation of geological features on borehole image logs (BHI) is not trivial, and it is susceptible to misinterpretation. Since the BHI are projected on a two-dimensional (2D) cylindrical plane view, any planar feature will be seen as sinusoids, which is very unusual to those who work on the 2D views, such as core slabs, road cuts, or even in a continuous view of a photograph. To interpret BHI with higher confidence, geologists and petrophysicists always search for field analogs, cores, or at least sidewall cores to calibrate their eyes for rock textures and structures that may be present in this kind of data. However, until now, only the cylindrical tomography log (image of the core tomography surface) is adequate for being truly compared with a borehole image view.

To expand the possibilities of the correlation between outcrop and borehole image logs, this paper brings a new methodology for the creation of pseudo-borehole images from outcrop photographs. The method consists of Python algorithms that generate a pseudo-volume from an outcrop image and extract a pseudo-image that respects the borehole dimensions. This method was validated by comparing the pseudo-images created from the slab of a core CT scan with the corresponding 2D plane view of the tomography log from the same core surface.

This invention was finally attested in outcrop photographs of different kinds of rocks and improved the interpretation of real borehole images. Alongside, the utilization of this method has shown good results for reproducing planar features and three-dimensional (3D) structures equal to or bigger than the borehole size. In this work, we discuss the scenarios where this method improves the confidence of image analysis, the pitfalls, and its potential to reduce misinterpretations. In addition, in this work, we show how pseudo-images can be useful to provide good geometric analogs for subsurface reservoir sections, making it possible to create suitable scenarios from outcrop geometries and their corresponding features on borehole image logs. Finally, the application of this method also has significant potential to develop input images for machine learning or other artificial computational intelligence systems.

Pushing the Envelope of Casing and Cement Inspection: Logging Two Casing Sizes Simultaneously and Setting a Cement Plug in a Single Run

Andrew Hawthorn, Baker Hughes; Tonje Winter, Var Energy; Laurent Delabroy, Aker BP; Nina Girneata, Mats Ingebretson, Iain Leslie, and Roger Steinsiek, Baker Hughes

Casing and cement inspection logging is critical for many well operations and is also, in many cases, a regulatory requirement. These measurements have traditionally been acquired on wireline. Recent developments have shown that azimuthal ultrasonic pulse-echo measurements can now be acquired on drillpipe-conveyed tools. This has opened up a window of opportunity for significant time savings by logging in parallel with existing rig operations and undergoing operations that are impossible with wireline-conveyed tools. A North Sea operator wished to maximize operational efficiency by logging the condition of the cement and, as a contingency, any wear on both a 13.375-in. casing and a 9.625-in. liner simultaneously. Additionally, a cement plug was set, all in the same operational run.

To achieve this, two drillpipe-conveyed tools were run in memory mode and spaced by several hundreds of meters, such that the top tool, which needed larger centralization, could not run into the top of the 9.625-in. liner. These tools both had three circumferentially arranged ultrasonic transducers, with the top tool centralized for the 13.375-in. casing and the bottom tool for the 9.625-in. liner. The relevant sections of both the 13.375-in. casing and the 9.625-in. liner could then be evaluated in a single logging run. By rotating the drillpipe and pumping, both relevant sections of the two sizes of well barrier fully acquired azimuthal data of their respective casing and liner. Subsequent to the logging, a cement plug was then set as the tools have a full through bore, allowing passage of cement through the tools.

The results were then analyzed through both rigsite and full waveform processing for evaluation of the condition of the casing (analysis of wear) and the material outside the casing in the annular space for cement analysis and barrier identification. Each individual transducer (three on each tool) was evaluated separately and then compared for additional quality control and interpretation. The data acquired were entirely sufficient to make an informed decision for the rest of the well operations. This run, combining dual-spaced tools run on drillpipe and cementing through the same string, is the world’s first instance of this type of logging ever recorded and had a significant impact on rig efficiency and savings. Traditionally, this data would have been acquired with two separate dedicated logging runs. Additionally, two different new types of cement with lower acoustic impedance than standard cements were logged, showing the applicability of this technology for lighter, nonstandard cements. Several other wells are now planned to operate in this unique way, pushing the envelope on how and when we acquire this critical well information.

Quantitative Evaluation for Fluid Components on 2D NMR Spectrum Using Image Boundary Tracking and Modified GMM Clustering Method

Jiawei Zhang, Guangzhi Liao, Lizhi Xiao, and Sihui Luo, China University of Petroleum, Beijing

Nuclear magnetic resonance (NMR) logging technology plays an important role in oil and gas exploration and rock sample analysis. However, there is a phenomenon of superposition of multiple fluid component signals in the (T_2, T_1) distribution, which makes the identification and quantitative calculation of each fluid component very difficult. In recent years, blind source separation (BSS) and cluster analysis methods have had difficulties in determining the number of fluid components, and BSS must decompose multiple-depth data and cannot identify the fluid of a two-dimensional (2D) NMR spectrum at a single depth.

In order to more accurately identify the types of fluid components and calculate the content of fluid components, this paper uses the image boundary tracking method to identify the images of the 2D NMR spectrum to determine the number and center distribution of fluid components. Aiming at the clustering method, a modified Gaussian mixture model (GMM) clustering method is proposed in this paper, based on the number of fluid components and the position of the center point determined by image recognition, which solves the problem that the traditional GMM method may have classification confusion.

Through numerical simulation experiments, the porosity and saturation of each fluid component calculated by the proposed method are compared with the K-means method and the traditional GMM method to verify the accuracy of the proposed method. The results show that this method can not only effectively identify the number of components in the 2D NMR spectrum but also has higher accuracy for the quantitative calculation results of each fluid component.

Simultaneous Correction of Shoulder-Bed and Anisotropy Effects on LWD Propagation Resistivity Logs in HAHZ Wells
Xizhou Yue, Guoyu Li, and Mingxue Ma, China Oilfield Services Ltd; Shanjun Li and John Zhou, Maxwell Dynamics, Inc.

Petrophysicists are often confounded by which one of the many resistivity logs should be used in formation evaluation. There is a diverse number of logging-while-drilling (LWD) propagation tools on the market from a wide range of service providers. Depending on the vendor, one may encounter as many as eight to 30 propagation resistivity curves. These logs have varying degrees of measurement accuracy and different response characteristics. Furthermore, it is well known that shoulder-bed and formation anisotropy significantly affect the propagation resistivity readings, especially in high-angle and horizontal (HAHZ) wells. Over the past two decades, a number of papers have discussed the importance of and the ways to solve for true resistivity from the apparent resistivity logs. Operators typically have to rely on each vendor to provide that vendor’s unique corrections, assuming the vendor is able to.

We developed a unified inversion processing algorithm for all LWD propagation resistivity measurements accounting for vendor diversities. Since the processing implementation covers all tools on the market, the developed algorithm accomplishes uniformity in processing and outcome, which is beneficial to those who have to deal with data sets from multiple vendors. Furthermore, the newly developed fast-processing algorithm considers both shoulder-bed and anisotropy effects jointly in a physically rigorous and mathematically efficient approach. The inversion algorithm based on the standard Gauss-Newton method is also adapted to provide a stable and accurate solution by allowing the users, when so desired, to introduce geologically meaningful constraints on processing parameters and/or weights on the input logs to the processing algorithm. The developed algorithm also considers the response characteristics observed from logs in various borehole and formation environments in an intelligent way. The tool measurement principles are taken into account to optimize the inversion solution further. The inversion solution derives the true resistivity R_t of the formation in the case of isotropic reservoir or the vertical and horizontal resistivities (R_v and R_h) if the formation is anisotropic.

Validation examples on the implemented shoulder-bed and anisotropy correction are provided in the paper with both numerically modeled logs and a number of field data sets. The paper will also demonstrate the benefits of applying such correction before any petrophysical interpretation.

Synergies Between RCAL, SCAL, and DRP to Obtain Faster, Cheaper, and More Accurate Rock Characterizations
Rodrigo Surmas and Marcelo Ramalho Albuquerque, Petrobras

In recent years, digital rock physics (DRP) has evolved significantly, diversifying its applications in numerical simulations for determining a series of petrophysical properties and automated image analysis using artificial-intelligence-based algorithms, among others, becoming a routine part of reservoir analysis at Petrobras. Although the area is often seen as antagonistic to routine and special core analysis (RCAL and SCAL), this view is mistaken, sometimes bringing unrealistic expectations about the scope of DRP applications and its relationship with these more traditional laboratory areas. This work will showcase DRP applications and discuss their relationship with traditional laboratory essays.

The first one is the rapid determination of porosity and absolute permeability directly from microtomography images using artificial intelligence algorithms. The benefit is to accelerate basic petrophysics results by about 4 months, with some loss of accuracy. This speed gain generates the expectation of replacing the traditional workflow with the digital rock workflow, but it is important to remember that its development was only possible because laboratory results were available and, moreover, were previously classified in terms of quality so they could effectively be used in neural network training. In this work, this workflow will be presented, comparing laboratory techniques and artificial intelligence in terms of cost, accuracy, and time for analysis.

During the construction of the digital rock model for the determination of special petrophysical properties, particularly relative permeability and capillary pressure, there are important uncertainties in digital rock that must be addressed for a truly representative rock model to be created. It is extremely rare that only one microtomographic image can simultaneously represent the largest and smallest pores present in a given rock, so a series of techniques must be applied to refine this rock model. Many of these techniques involve calibrating the digital rock model with cheaper and quickly obtainable data from traditional laboratory testing, such as:

- Sample saturation with doped solution followed by microtomographic imaging to improve the representation of the sample's porosity map
- Calibration of digital rock results with mercury injection results to improve the representation of sub-resolution porosity
- Adjustment of tracer test with simulation results to refine the permeability map of a given sample

These techniques will be discussed, and their applications will be presented in carbonate reservoirs. Well-calibrated digital rock characterizations, when calibrated with traditional testing, bring very positive prospects for improving the accuracy of digital analysis, effectively expanding the application of the laboratory and creating synergy for the determination of petrophysical properties with fewer uncertainties.

NMR TECHNOLOGY AND APPLICATIONS – PORES AND FLUIDS DISTRIBUTION

A Physics-Informed Deep-Learning Architecture for Transforming NMR T_2 to MICP Pore Throats for Carbonate Rocks

Wei Shao and Songhua Chen, Halliburton; Shouxiang (Mark) Ma, Gabor Hursan, and Abdullah Alakeely, Aramco

The transformation of NMR relaxation time (T_2) to mercury injection capillary pressure (MICP) pore-throat size (PTS) distribution is affected by many attributes of measurements and formation characteristics. For complex carbonate rocks, these attributes can be highly heterogeneous and nonlinear. Data-driven solutions, such as deep learning (DL), can be a vital approach to approximate the complicated relationship between T_2 and PTS. However, DL models must be chosen judiciously so they retain key features but avoid instability due to limited core data for training and uncertainties in NMR measurements. In this paper, a physics-informed DL architecture is developed for complex carbonate formations to map NMR T_2 distributions to MICP PTS.

A data set of about 40 carbonate cores is used for this study, with measurements including porosity, permeability, MICP, and NMR T_2. Rock qualities of those samples vary drastically, with porosity ranging from 2 to 25 p.u., permeability from less than 0.1 md to more than 1 Darcy, and a large variation in pore structure represented by the amounts of micropores, mesopores, and macropores existing among the samples.

The core data are first augmented with two approaches. Approach No. 1 adds various degrees of random noise to the measured core data, mimicking the noise in NMR logs acquired in different environments. Approach No. 2 randomly combines core data of different samples, with added various degrees of random noise, to ensure wide variations in rock pore structures for training and testing.

The physics-informed DL model for NMR to MICP transformation consists of two deep neural network (NN) models with the physics of NMR response incorporated into the loss function. The outputs of the model are not only MICP PTS distributions but also NMR T_2 distributions. Furthermore, total porosity, partial porosities, and echo-fitting errors are also the outputs of the model due to its unique two-level NN architecture. Hence, unlike the traditional NN, the performance of the physics-informed DL model can be monitored with physical parameters such as total porosity, partial porosities, and echo-fitting errors.

The DL model was trained with the data set augmented with Approach No. 2 described above by repeatedly and randomly selecting two core plugs' data to combine at a time for the total of 8,000 generated augmented samples. The testing was performed with another data set of 8,000 samples augmented with both Approaches Nos. 1 and 2 so that the test data sets include noise-contaminated single core sample data as well as randomly combined three core plug measurement data, which ensures the training and testing data are independent.

The physics-informed DL-predicted total porosity is compared with the total porosity augmented from NMR measurements for quality control, and the results are extremely good.

The physics-informed DL-predicted NMR T_2 (DL) matched well with T_2 augmented from measured NMR T_2, and T_2 inverted from augmented NMR echoes and predicted PTS matched well with PTS augmented from MICP measurements (Fig. 1).

The robustness of the DL model is further validated by comparing the pore typing results derived from DL-predicted PTS distributions with the traditional methods of using a single conversion factor from NMR T_2 to MICP PTS.

This study shows that, compared with the traditional methods, the physics-informed DL model can approximate the complicated relationships between NMR T_2 and MICP PTS due to the enforced physical constraints to improve the ability to extrapolate accurately beyond the training data.

Characterizing Thin-Bed Responses in Horizontal Wells Using LWD NMR Tools: Insights From a Water Tank Experiment

David Allen, Zeyad Ramadan, and Ahmed Allam, SLB

Logging-while-drilling (LWD) nuclear magnetic resonance (NMR) tools play a crucial role in reservoir evaluation. However, in horizontal wells with thin layers smaller than the tool's sensitive region, deciphering the contribution of each layer to the total signal poses a formidable challenge. This complexity arises from the layer's position relative to the cylindrical sensitive region, making it challenging to develop accurate forward models for LWD NMR tools in such scenarios. A theoretical response scheme was constructed to try to explain how the LWD NMR tools respond in such scenarios. However, conducting an experiment to validate the theory was a must to develop algorithms that can be used in forward modeling such complex response cases.

To address this challenge, we designed and executed an innovative experiment within a controlled environment—a water tank—that replicates the intricate conditions found in horizontal wells with thin beds. To overcome the practical limitations of measuring specific thin-bed characteristics at various positions in a laboratory, we used the calibration setup of a slimhole LWD NMR tool for measurement purposes. The experiment involved a systematic reduction of the water level in the calibration tank in discrete increments, emulating the vertical movement of a thin bed within the horizontal cylindrical sensitive region of the tool. Data acquisition was conducted at predefined intervals as the water level progressively decreased until the tank was empty.

Through meticulous processing of the acquired water level data, we assessed the individual contribution of each level drop to the original signal. The culmination of this effort yielded a comprehensive lookup table containing essential coefficients for future-forward modeling exercises involving the slimhole LWD NMR tool in similarly challenging conditions. We believe that the outcomes of this experiment hold substantial promise for estimating sand volume in thinly bedded reservoirs. This can be achieved by comparing the actual LWD NMR tool measurements acquired in such challenging reservoirs with forward models constructed using the coefficients derived from this study.

Comparison of PCA and Autoencoder Compression for Telemetry of Logging-While-Drilling NMR Measurements

Wolfgang Weinzierl, Oliver Mohnke, Lucas Kirschbaum, Radu Coman, and Holger Thern, Baker Hughes

Compression is an essential aspect of real-time operations as the bandwidth of transmitted information is very limited during logging while drilling. Processing of nuclear magnetic resonance (NMR) data involves the inversion of echo trains (ET), which are compressed downhole and transmitted via telemetry. The performance of individual NMR ET compression techniques also needs to be evaluated on the input signal level because the comparison of inversion results is highly dependent on regularization. Improved compression is key to properly encoding and decoding rate of penetration (ROP)-dependent motion effects with the goal of improving the accuracy of NMR T_2 distribution at increased ROP in real time.

The value of information of an ET differs over its range. First, early echoes have a large impact on the total porosity. They require a large contribution to the computation of, i.e., root-mean-squared error, used for comparing compression techniques. Secondly, non-exponential motion artifacts have a non-negligible impact on the inversion for cutoff-dependent volumetrics with increasing ROP. We propose a logarithmic weighting of the error contribution when comparing different compression implementations.

Principal component analysis (PCA) is a linear transformation and is, therefore, very robust. It can reduce the dimensionality of data even given highly clustered inputs. In a previous implementation of PCA, ROP motion effects were neglected in developing the basis set of vectors at the low ROP used in earlier drilling operations. However, neglecting ROP motion effects may have noticeable effects on inversion results for porosity and volumetrics at increased ROP. Therefore, new PCA basis vectors are developed to account for these motion effects.

Parallel with the development of the enhanced PCA basis vectors, an alternative denoising and compression concept utilizing a neural network autoencoder was developed and evaluated. The autoencoder first encodes the input data to a lower-dimensional representation. The original input is reconstructed from this compact latent space encoding using a decoding block. The autoencoder is trained on a synthetic data set comprising different subsurface properties and acquisition parameters learning the salient features.

With the aim of implementing the encoding block on a low latency/memory device downhole, optimization of the network topology involved both the size of the network and the accuracy of the decompressed signals for real-time NMR inversion. Validation of the PCA and autoencoder compression is performed using inverted volumetrics of the encoded and decoded ETs.

A new PCA basis for NMR data compression was developed to properly encode and decode ROP-related motion effects. Its performance was compared to a conventional compression technique. In addition, results of a denoising and compression algorithm for NMR ET based on a fully connected neural network autoencoder are presented. Tests show an improvement in the axial motion effects introduced by increasing ROP.

By using a weighted error metric to compare individual compression implementations, it is possible to focus on the value of information on the early echoes. Accounting for ROP motion effects in the development of a new PCA basis, as well as using the autoencoder in training, improves the inversion of movable and irreducible fluid components. In addition, a reduction in the amount of data to be transmitted allows for a further decrease in the telemetry footprint of the NMR measurement. Both approaches increase the amount of transmitted information while improving the evaluation of the subsurface environment.

NMR Characterization Solving Oil-Water Contact Uncertainty: A Presalt Case Study
Moacyr do Nascimento, Jefferson Farrapo, Leonardo Gonçalves, Augusto Rego, and Frederico Schuab, Petrobras

The study is focused on a particular case of a well drilled in a heavy oil-bearing presalt formation. This is an atypical situation for presalt accumulations wherein there was great uncertainty about the oil-water contact (OWC) and the free-water level (FWL). Preliminary petrophysical evaluations resulted in a shallower OWC than the NMR log data interpretation, which suggested a deeper OWC. This uncertainty motivated a thorough NMR response characterization of 11 sidewall cores (SWC) in fresh-state condition, as well as bulk petroleum and mud-filtrate samples, to better define the transition zone between the reservoir and its underlying aquifer.

The SWC were carefully selected from an interval more extensive than the transition zone. Shallower samples were taken from a confidence interval in the irreducible water saturation condition, and deeper samples from the aquifer range to serve as a water saturation reference. Transverse relaxation time (T_2) spectra and diffusion-T_2 (D-T_2) correlation maps for all rocks and fluid samples were obtained from NMR laboratory analysis.

The S-curve criterion was used to set the amount of regularization of each inversion whenever the square norm of residuals could not meet the measured noise level, and the inversion problem was discretized in such a way as to directly produce a volume distribution over the relaxation time interval of interest. This method allowed the introduction of oil saturation index for each rock sample by establishing a direct correspondence between core and oil T_2 spectra. The calculation rested under the assumptions that (1) the sample is partially oil-saturated and (2) its oil response is unaffected by surface interactions. The latter hypothesis is likely valid regardless of the wettability character of the oil inside the pore volume, for most common natural oil compositions at least, therefore making the approach generally applicable. However, dense oil and capillary-bound water T_2 signatures usually fall within the same range of relaxation times. Hence, such correspondence of T_2 spectra alone may lead to false interpretations in situations wherein rock samples have little or no oil in them, and yet their spectra match the oil signature well over its support interval of relaxation times. In order to differentiate capillary water and oil signatures, D-T_2 correlation maps were incorporated into the analysis. It has been observed in our case study that the dispersion of diffusivity is a reliable fluid classifier over the range of relaxation times in which those signatures concur, namely, because water diffusivity is more dispersed due to changes in molecular transport characteristics imparted by contacts with the pore wall (whenever the system is water-wet).

Based on the results generated for the 11 samples and the developed methodology, it was possible to reposition the conservative OWC roughly 40 m deeper than the initial prognosis, significantly reducing the uncertainty about fluid conformation in the transition zone. The conclusion was based on the depth of the deepest SWC in which a clear signature of the formation oil is visible, through correspondence, in its T_2 spectrum, and the rise of capillary water saturation is undeniable. Subsequently, the FWL was determined using a modular formation dynamics tester tool, confirming the reasonableness of the entire approach. Thus, laboratory characterization through NMR is an advantageous and relatively inexpensive technique to support decisions regarding the distribution of reservoir fluids.

Method for Shortening Echo Interval of Nuclear Magnetic Resonance Downhole Instruments
Wei Liu, Wenxiu Zhang, and Wenxuan Chen, Institute of Geology and Geophysics, Chinese Academy of Sciences; Guangzhi Liao, College of Geophysics, China University of Petroleum-Beijing

With the increasing development of complex oil and gas reservoirs such as shale oil, the precise characterization of their pore structure has become a key issue in shale oil exploration and development. In order to meet the exploration and development needs of “low porosity, low permeability, and tight” oil and gas reservoirs, such as shale oil reservoirs, for complex oil and gas reservoirs with strong compactness, the fluid properties of reservoir micropores are studied to determine the pore size of the fluid space. It is necessary to enhance the detection ability of underground nuclear magnetic resonance instruments and achieve the recognition ability of short relaxation component information generated by fluids in microporous structures. Given the demand for short relaxation component measurement caused by factors such as tight pore structure in reservoirs, it is urgent to improve the accuracy of the instrument in extracting short relaxation component information.

In response to the scientific issue of using underground nuclear magnetic resonance technology to obtain fluid information on tight reservoir micropore structure and pore-throat permeability, this project proposes a radio frequency antenna quality factor conversion method. Without changing the excitation efficiency of high-voltage radio frequency pulses and the signal-to-noise ratio of echo signal acquisition, the time for measuring pulse sequences is shortened; that is, the echo spacing is shortened, and the measurement of short relaxation components using underground nuclear magnetic resonance instruments is achieved. By analyzing the pulse sequence of nuclear magnetic resonance signals excited by instruments and utilizing the energy conversion principle of radio frequency antennas, the frequency response characteristics of antenna resonance networks at different periods of nuclear magnetic pulse sequences are studied. A physical parameter model of radio frequency antennas with short echo spacing is constructed to achieve compression of echo spacing at different periods. During the antenna recovery period, an adaptive fast shutdown technology was proposed. Identify changes in antenna voltage and current through software control to achieve a graded response. Through hardware design, a high-voltage energy release execution unit is constructed to achieve the design of a short echo spacing acquisition system for pulse sequences.

Conduct testing experiments on the experimental prototype of the nuclear magnetic resonance logging-while-drilling instrument using this method. The experimental results show that the signal-to-noise ratio of the instrument’s echo signal is good, and the distinction between ringing noise and echo signal is obvious. The test results are consistent with the simulation results and can achieve data collection with short echo spacing. This verifies the design and measurement function of the nuclear magnetic resonance short echo spacing instrument while drilling. By shortening the echo spacing of the pulse sequence using this method, the instrument measurement time can be reduced, and the rapidly decaying short relaxation component information in tight reservoirs can be obtained, providing technical support for achieving refined evaluation of pore fluids in tight reservoirs.

NUCLEAR TECHNOLOGY AND APPLICATIONS – MINERALOGY, FLUIDS, AND TRUE POROSITY

A Novel Determining Borehole Fluid Density and Imaging Method Using X-ray Source
Luyu Zhong, Feng Zhang, Yiming Yu, Zhenhua Hu, and Yimula Abulahai, China University of Petroleum (East China)

The wellbore's integrity can be compromised due to tool deformation and the fall of downhole fish, resulting in blockages. In order to guarantee the secure and effective restoration of a malfunctioning wellbore, it is essential that the wellbore must be the initial investigation during the repair procedure. Although the introduction of well visualization techniques such as ultrasonic imaging and downhole television has greatly reduced the risk of well intervention, the imaging capabilities of these techniques are still limited when the fluid is unknown and opaque. This presents a new challenge when it comes to completing downhole probes in a safe, efficient, and cost-effective manner. Historically, the high penetration and interaction between X-rays and matter have been used to image objects in fluids, but there have been few studies on imaging response theory and correction methods for imaging. In this study, the photon transport theory of downhole X-ray front-view imaging is proposed to address the poor understanding of the mechanism and influencing factors. To overcome the difficulties in quantifying the influencing factors, the correction method of the X-ray flux distribution-fluid layer thickness mapping library is proposed according to the photon transport theory, which enables the adaptive response correction of the mapping library to the fluid parameter in the imaging inversion.

The X-ray flux distribution is recorded using a detection system consisting of a matrix detector, an imaging aperture, and an X-ray source. Irrational structural parameters and fluid corrections affect the X-ray flux distribution response to water layer thickness, leading to inverse imaging failures, with single Compton scattering contributing more than 90%. Therefore, it is essential to develop the photon transport theory for forward-looking imaging, which is the basis for the detection parameters of fluid and the correction method, in order to provide theoretical support for the design of the device structure. In this paper, mathematical expressions are derived to quantify the effect of instrumental parameters on the X-ray flux distribution, and the patterns of forward data response are consistent with the theoretical response form. To realize the measurement of fluid parameters and adaptive correction imaging, a parameters identification method and response library correction method are proposed, while scattering theory shows that the effect of fluid parameters is mainly related to the attenuation coefficient. Simulation results indicate the efficacy of the method in identifying fluid density in cased wells and adapting image libraries with over 99.8% confidence. Additionally, effective detection distances of 10 cm and 1 mm image inversion resolution were achieved.

A Novel Method for Obtaining Formation Water Salinity Utilizing Elemental Spectroscopy Logging
Jilin Fan, Wenhui Chen, and Aizhong Yue, China National Logging Corporation; Qiong Zhang, University of Electronic Science and Technology; Feng Zhang, China University of Petroleum (East China)

The accurate determination of formation water salinity is crucial for petroleum exploration and development as it plays a significant role in determining reservoir parameters. In particular, salinity determines the sigma value of formation water in pulsed-neutron capture logging, which is essential for calculating reservoir oil saturation. Therefore, accurate measurement of formation water salinity provides vital information for determining reservoir parameters, understanding the origin of formation water salinity, assessing oil and gas preservation conditions, and predicting oil reserves. Currently, the determination of borehole fluid and formation water salinity typically involves sampling analysis, which can be expensive and may not accurately represent the salinity distribution of the reservoir. Additionally, the presence of shale presents challenges to the effectiveness of formation resistivity logging in calculating formation water salinity. In cases where the salinity is high, the formation resistivity logging may fail to accurately calculate the salinity, which is a difficulty in determining the salinity of the formation water.

In the field of nuclear logging, attempts have been made to monitor formation water salinity by combining thermal neutron count and chlorine yield. However, this method has limitations and cannot be applied to reservoirs with complex lithology. Therefore, addressing the calculation error of chlorine yield and content is a crucial issue to overcome in the quantitative monitoring of formation water salinity. This paper presents a novel joint bispectral method for accurately calculating formation water salinity using elemental spectroscopy logging technology. The method utilizes inelastic and capture energy spectra to determine the element yield, which is then converted into the atomic number proportion (ANP) of each element. Based on the ANP values and the relative atomic mass of the element, the formation chlorine content is directly calculated. Subsequently, a high-precision calculation model of formation water salinity is constructed by utilizing formation density and porosity information.

Compared to the traditional oxygen closure model, the joint bispectral method improves the calculation accuracy of chlorine content by an order of magnitude and keeps the calculation error of formation water salinity within 2 g/L. The field logging example further demonstrates the high agreement between the calculated results of formation water salinity and laboratory analysis results, validating the validity and accuracy of the joint bispectral method. This method is not affected by the mineral composition of the formation, making it highly versatile and suitable for a wide range of applications. It provides valuable technical support for the exploration and development of oil and gas in saltwater-bearing reservoirs.

Advancements in Mudlogging Automation and Identification of Facies Using XRF and Automated Sampling Machine
Carolina Mayorga, Andreina Liborius Parada, Carl Symcox, and Dave Tonner, Diversified Well Logging

Mudlogging has historically played a pivotal role in the identification and characterization of lithology in geological investigations. The integration of traditional mudlogging methods with X-ray fluorescence (XRF) analysis signifies a significant advancement, particularly when dealing with geologically complex or seemingly homogeneous rock formations such as shales and siltstones.

Traditional techniques for assessing formations, encompassing both surface and downhole logging, as well as core sample acquisition, entail substantial expenses, risks, and uncertainties. This paper introduces an innovative approach that harnesses automated workflows, quantitative analysis of rock and gas compositions, and the seamless integration of data science and artificial intelligence. This amalgamation introduces a fresh suite of logging methodologies as a compelling alternative to conventional practices, offering a distinct perspective into subsurface dynamics that remains largely unexplored.

The resultant data outputs assume a critical role in shaping pivotal decisions related to wellbore construction, encompassing fault determination and geosteering. Moreover, they deliver indispensable inputs for refining well placement, optimizing spacing strategies, augmenting drilling efficiency, and, ultimately, fine-tuning completion and production processes. This presentation is enriched by a series of case studies and recent field deployments, which serve to underscore the efficacy of this innovative approach.

A noteworthy advancement in automation is demonstrated through the implementation of automatic sampling directly from the possum belly into the mudlogging unit at intervals as frequent as every 2 minutes. This advancement enhances sample resolution, reduces sample capture and description time, and minimizes the need for on-site personnel, thereby lowering the likelihood of quality, health, safety, and environmental (QHSE) incidents. It also affords mudloggers more time for detailed sample descriptions and photography.

To exemplify the practicality of this methodology, this study presents a case study from Texas, illustrating the effective utilization of chemical elemental compositions obtained from drill cuttings to establish a comprehensive chemofacies model and chemostratigraphic sequence using elemental data and machine learning to classify and predict facies.

By harnessing advanced geoscience data statistical techniques, this approach streamlines the process of identifying meaningful patterns, resulting in refined reservoir characterization and improved capital efficiency.

Description and Benefits of Drilling Horizontal Exploration and Delineation Wells, Supported by Deployment of New Sensors and Digital Technologies
Jean Michel Denichou, SLB; Torstein Skorve, Artur Kotwicki, and Aasmund Olav Lovestad, Aker BP; Sigurd Nyboe, Mathias Horstmann, Martine Wenang, and Motaz Zeidan, SLB

The necessity for drilling multiple vertical or sub-vertical delineation wells to appraise the extent of a discovery has been overcome in this project by the innovative combination of the latest logging-while-drilling (LWD) formation properties and reservoir mapping tools along horizontal trajectories.

By having horizontal wells, operators can gain extended benefits in delineating the hydrocarbon prospects and reservoir structures. Another advantage is the ability to reach and detect lateral boundaries/extension of the reservoir which would be a critical input for hydrocarbon volume calculation in place. Mapping intra-reservoir heterogeneities, current oil-water contact, and/or gas-oil contact would also be possible by drilling a horizontal appraisal well. Lastly, minimizing the number of overburden section drilling could result in significant savings and reduce the environmental impact of the campaign.

Øst Frigg Field was produced, from both the Alfa and Beta structures, for gas until 1997, when it was abandoned. A relatively thin oil rim of 7 and 10 m on Alfa and Beta, respectively, was detected by the initial exploration wells drilled on the Øst Frigg Alfa and Beta structures. However, oil was never produced through former development wells. Three horizontal wells were planned to appraise the Beta, Alfa, and Epsilon structures within the Yggdrasil area. The main objective of the project was to improve understanding of the hydrocarbon resource potential, particularly the presence of oil in the Frigg sand reservoir for the three structures.

Well A was the first well drilled along the Beta structure, which propagates towards the west side of the Øst Frigg Beta structure with 3,010 m MD of reservoir section drilled to TD point. The ultradeep azimuthal resistivity tool (UDAR) provided delineation of the conductive roof and the conductive base of the hydrocarbon-filled Frigg sand reservoir. The well revealed a continuous oil column up to 25 m thick and the presence of an oil-water contact.

Well C, the second well drilled, appraised the northern part of the Beta and explored the Alfa structure, which propagates towards the north side of the field. The well proved the northern extent of the oil accumulation and mapped the oil-water contact. Advanced logging-while-drilling (LWD) NMR and spectroscopy measurements fed continuous petrophysical interpretations, identifying the lithology and special minerals like siderite using a variable autoencoder (VAE) in a neural network (NN). This was confirmed through X-ray diffraction (XRD) analysis done on cuttings, validating the spectroscopy results. Continuous LWD spectroscopy and NMR data (real time and post-TD) drove the quantification of residual gas vs. oil in the produced zones. Both were used as input to multimineralogical models (QElan). The well was called early TD after 1,955 m MD length to avoid the risk of drilling extensively in the shaly section.

Well B was the third well drilled, targeting the Epsilon structure towards the east side of the field with 6,012 m MD of reservoir section drilled to TD point. It revealed an oil column up to 15 m in thickness. Up to 30 m of an overlying gas cap in the Epsilon structure was identified by density-neutron and delineated with UDAR interpretation. Evidence of oil even until 6,000+ m MD lateral length at TD point was delivered, leading to estimate the volumetric oil in place.

This case study demonstrates the capacity to reduce the number of exploration and delineation wells as the latest technological development in LWD has overcome past limitations for their deployment in horizontal wells drilled for exploration and delineation. By the time the third horizontal well reached TD, the team had set a record for the longest exploration well ever drilled on the Norwegian Continental Shelf (6,012 m MD length), and in total, approximately 11,000 m of horizontal reservoir data was acquired. Preliminary calculations show 53 to 90 million recoverable oil equivalents*.

Enhancing Lithological Evaluation in Complex Triassic Reservoirs: A Comparative Analysis of LWD Spectroscopy and Standard Cuttings Examination
Rubi Rodriguez and Mathias Horstmann, SLB; Yngve Bolstad Johansen and Egil Romsås Fjeldberg, Aker BP; Francoise Allioli, Karim Bondabou, and Andrea Di Daniel, SLB

Accurate reservoir assessment and continual evaluation are imperative for optimizing hydrocarbon recovery in Late Triassic fluvial sandstone reservoirs in the Norwegian North Sea. This study addresses the challenges posed by a heterogeneous clastic sequence with intricate mineral compositions, including a weathering profile containing calcitic and dolomitic carbonates. Horizontal drilling, employed to maximize net pay, revealed inconsistencies between standard wellsite cuttings descriptions and high-resolution logging-while-drilling (LWD) gamma ray spectroscopy. A comprehensive cuttings evaluation incorporating X-ray diffraction (XRD) and X-ray fluorescence (XRF) analyses was necessary to validate mineralogical compositions.

LWD high-resolution pulsed-neutron-induced gamma ray spectroscopy, utilizing an advanced lanthanum bromide (LaBr) spectroscopy detector and artificial-neural-network-based mineralogy algorithm, facilitated real-time elemental composition determination. This technology offered advantages in identifying calcite and dolomite fractions during drilling without user parameterization. While cuttings descriptions can be subjective, especially for dolomite identification, LWD spectroscopy demonstrated the identification and quantification of calcite and dolomite, revealing discrepancies with cuttings descriptions. To address these differences, stored drill cuttings were subjected to XRD and XRF laboratory analyses for consistent mineralogical study.

The study underscored the limitations of standard cuttings descriptions in capturing key mineralogical markers, such as dolomite and calcite, in complex Triassic formations. Conversely, LWD spectroscopy accurately identified these minerals, indicating varying degrees of dolomitization across three wells. Elemental proxies, such as sulfur and pyrite, allowed tracing changes in depositional environments from oxic Triassic to anoxic Jurassic formations.

The high-resolution LWD spectroscopy tool emerged as a reliable real-time solution for mineralogical analysis, providing robust estimates of total porosity, water saturation, and permeability. Dolomitization levels, crucial for understanding reservoir characteristics, were consistently identified by the downhole tool, aiding in mapping the weathering profile. Advanced surface logging using XRD and XRF analyses offered a more consistent mineralogy determination compared to standard cuttings analysis. Consequently, the study recommends the application of LWD spectroscopy in complex lithologies, validating its reliability through advanced surface logging techniques.

Experimental Validation of a Sensitivity Functions Sigma Simulator in a Cased-Hole Environment With Calibration Facility and Production Well Data

Geoffrey Varignier, Pïerre Chuilon, Emmanuel Caroli, and Benoit Guivarch, TotalEnergies; Heiko Reinhardt, ANTARES; Valentin Fondement, Thomas Marchais, Cedric Carasco, and Bertrand Perot, CEA; Mai-Linh Doan, University of Grenoble Alpes, University of Savoie Mont Blanc, CNRS, IRD, Univ. Gustave Eiffel, ISTerre; Johann Collot, LPSC-IN2P3

Mature producing areas face the challenge of abandoning numerous wells safely. Cased-hole logs can play a key role in the integrity and confinement assessment. Therefore, the industrial problem today is no longer to characterize some petrophysical properties of the formation (e.g., porosity, density, lithology, oil or gas saturation, etc.) but also some components of the well (e.g., drilling fluids, casing, and cement). Due to the large number of variables, a multiphysics inversion considering simultaneously different nuclear log inputs is mandatory. During the past 20 years, Austin University introduced the concept of sensitivity functions to simulate logs and allow the inversion of formation properties. It has been successfully tested in an open hole. But, for cased hole, the robustness of sensitivity-function-based inversions relies on the ability of the forward modeling to closely reproduce the nuclear tools responses in the broad variety of wellbore environments. This validation was performed with a dedicated experimental setup, and the results are detailed in this paper.

In the first part, the concept of sensitivity function is discussed for a neutron-gamma sigma tool using nuclear Monte Carlo simulations and measurements acquired in both open hole and cased hole with two geometrical perturbations (axial and radial), characterized rock standards, and an oil and gas industry logging tool. This study also proposes to benchmark the numerical methods for calculating the sensitivity functions by comparing two different approaches: “Importance method” using MCNP and “Particle Tracking method” using GEANT4, two independent Monte Carlo modeling softwares. Sigma neutron-gamma tools are composed of either two detectors or three or four detectors. The apparent formation sigma measured on the detectors is different from the intrinsic sigma value in the zone of investigation. These individual sigma values are influenced at different degrees by the diffusion effect and the well components (i.e., casing, cement, etc.). The challenge for the log simulator is to reproduce all of those effects correctly and predict the accurate apparent sigma values delivered by each detector. To that end, we compare in a second part the predicted sigma logs, obtained from the forward modeling using the sensitivity functions calculated using different methods, and the measured sigma logs acquired in laboratory rock standards having strong contrasts of petrophysical properties.

The result of the first part shows some discrepancies between the calculated sensitivity functions and the measured ones (i.e., using a commercial tool), both in radial and axial directions, according to the computation methods (i.e., “Importance method” or “Particle Tracking” method). Nevertheless, the overall agreement between the calculations and the measurements is sufficient to secure the fundamental physics behind the concept of sensitivity function applied to cased hole. In a previous work (in press), forward algorithms have proven their effectiveness in correctly predicting neutron-porosity logs measured in a cased-hole and openhole laboratory rock standard, where casing and cement significantly impact the raw porosity measurement. The objective of the second part is to deploy the same workflow to secure the reliability of sensitivity functions based on the log simulator to predict relevant sigma logs (considering the effects of casing and cement plus the effects of diffusion). Thus, sigma logs forward predictions are compared with measurements in laboratory rock standard and real oilfield cased-hole logs. The prospect of this work is to extend the qualification of sensitivity function forward modeling to other nuclear measurements such as carbon/oxygen and litho-density.

Geochemical Logging to Anticipate CO_2 Reactions: New Reactivity Estimates and CO_2 Storage Simulations

Paul R. Craddock, Jeffrey Miles, and Sangcheol Yoon, Schlumberger-Doll Research; Soham Sheth and Laurent Mosse, SLB

Large-scale geological storage of CO_2 is widely considered necessary to mitigate detrimental effects on the climate. Discussions of formation evaluation in carbon capture and storage (CCS) often focus on the central themes of capacity, injectivity, and containment. The chemical reactions induced by CO_2 in rock-fluid systems are usually a secondary consideration, representing one of the less well-developed aspects of CO_2 storage assessment. The impact of CO_2-driven reactions can range from negligible to significant, depending on lithology and fluid composition. Water evaporates into dry CO_2, enabling the precipitation of salt from brine. Acidic CO_2-bearing solutions can dissolve primary minerals and precipitate secondary minerals. These phenomena may drive positive or negative changes in porosity and permeability on different time scales. The significance varies for minerals of siliciclastic, carbonate, and igneous rocks, and their effects touch on all the key operational criteria. Formation evaluation should play an essential role in predicting the evolution of CO_2-driven reactions and in designing strategies to avoid problems. In this work, we develop the connection between downhole logs and CO_2-driven reactions at two important levels: early-stage petrophysical evaluation and more detailed reservoir simulations.

We first introduce analytical models for CO_2 reactivity based on petrophysical logs and foundational expressions for chemical reaction rates. The kinetics of mineral dissolution and precipitation are used to estimate initial rates of chemical reactions. Geochemical logs from elemental spectroscopy provide essential information on mineralogy and lithology; we adapt and extend methods that are established from oil and gas reservoirs. Information on water composition is important. Insight can be derived from several means, including a chlorine measurement from elemental spectroscopy, the macroscopic cross-section sigma, dielectric dispersion, resistivity, or local knowledge. The surface area for reactions is driven by porosity, mineralogy, and optional methods to infer pore-size distribution.

Numerical simulations provide a more comprehensive way to predict the impact and extent of CO_2 reactions over long time scales. Several options exist for modeling reactive fluid transport, including commercial software and codes from US national laboratories and government agencies. We demonstrate results from multiple codes for 3D multiphase reactive transport simulation. Sensitivity studies illustrate the importance of accurate knowledge of formation properties. A global sensitivity analysis shows the variation of numerical results on CO_2 saturation, plume extent, formation porosity, and fluid pH with respect to key parameters of formation evaluation. The results imply that correct information on mineralogy, pore structure, and fluid compositions are all essential. We evaluate the agreement of the initial log-based reactivity estimates with the more complete 3D simulations. Examples are provided for CO_2 injection simulations based on real-field CCS operations.

Geochemistry and Saturation Applications Utilizing a New Slim Pulsed-Neutron Technology
John Savage, Weijun Guo, Fransiska Goenawan, Hernan Mora, and Sushovon Roy, Halliburton

As the oil and gas industry continues to mature, wells are drilled in increasingly challenging environments, often putting the formation evaluation program in an openhole environment at risk. Even if the well is accessible, the cost and risk of a complete multi-run openhole formation evaluation program can be prohibitive; however, it is still required to identify hydrocarbons in complex reservoirs. These and other considerations push operators more than ever to find accurate and complete formation evaluation in a rigless environment after the completion has been run. Logging runs through the completion reduce both cost and risk, where downhole tools are better protected and efficient conveyance options such as slickline is feasible with memory-capable tools. Cased-hole logging data have historically been limited as compared to the vast data that can be acquired in an openhole environment. Additionally, the range of conditions encountered in a cased-hole environment and the complexity of the completions will challenge even robust environmental corrections models, putting accuracy at risk. Completions with smaller tubing force the evaluation tools further away from the formation being evaluated and limit the OD of the tools being conveyed through the completion. The statistical nature of spectral nuclear technologies is particularly heavily affected by these constraints.

Pulsed-neutron formation evaluation has historically successfully been employed for water, oil, and gas saturations, whether for initial input into a petrophysical model or as part of a time-lapse well monitoring program. Advancements in electronics and scintillator materials that take advantage of high-yield neutron generators work together to improve the accuracy of the raw output. Continued improvements in MCNP nuclear modeling software coupled with a large variety of characterization lab conditions have improved validation, stretching the limits for the specified operating environment. Individual elemental yields have been fully characterized, both with the neutron generator active and from passive mode with the generator off. Processing software has been developed concurrently that incorporates the traditional parameters with several additional parameters, such as cement density.

The new multidetector pulsed-neutron tool can be conveyed in a wide range of borehole sizes, completion configurations, and borehole fluid types with a more accurate response across this array of challenging conditions. The new porosity ratio provides excellent precision throughout a wide range of porosity in known and mixed salinity environments. A comprehensive range of characterized elemental yields combined with spectral natural gamma measurements from the same tool enables valuable mineralogy data to be acquired through tubing. The inclusion of a direct measurement of total carbon yield from the inelastic spectrum lends to accurate physics-based total organic carbon (TOC) output that can aid in evaluating unconventional reservoirs. It is memory capable, storing all data, including 512 channel capture and inelastic energy spectra for each detector via slickline or coiled tubing. Digital slickline conveyance allows basic QC data to be transmitted to surface in real time. When full surface readout is required, a new telemetry package transmits all data on any traditional mono-conductor cable and on hybrid fiber-optic cable systems.

The Cased Oil Saturation Determination Method Based on Gamma-Thermal Neutron Response
Guofeng Yang, Wenzheng Peng, Hongfa Ye, Zhengyan Wang, Meng Chen, and Xiangjun Liu, School of Geoscience and Technology, Southwest Petroleum University

Cased oil saturation is an essential parameter for middle and late oilfield development, which can provide the basis for the development program design. Neutron-gamma logging has been widely used in the determination of cased oil saturation. Recently, carbon/oxygen (C/O) logging and pulsed-neutron capture (PNC) logging extract carbon-oxygen ratio (C/O) and capture cross section (sigma) from the measured energy and time spectra to evaluate the saturation. However, the spectral quality seriously affects the performances of the two classical methods and requires complicated spectral processing and environmental correction. Therefore, a novel cased oil saturation determination method is proposed based on the neutron-induced gamma rays and thermal neutron count. The proposed method does not require additional spectral processing and has higher statistical accuracy. First, the relationship between the detected capture gamma rays and the thermal neutron counts was described in theory to illustrate the feasibility of using the gamma-thermal neutron response to evaluate the cased oil saturation. Then, the test pit experiments were performed to collect the capture gamma spectra and calibrate the Monte Carlo simulation model to ensure the simulation results could reflect the real response of the instrument. After the benchmark, a new practical cased oil saturation evaluation parameter was introduced by the counts of the dual thermal neutron detectors and a single scintillator detector. Furthermore, Monte Carlo simulated case studies were conducted to analyze the response characteristics of the proposed evaluation parameter under different environmental conditions. The cased oil saturation can be calculated from the envelope established by the evaluation parameter in response to the oil and water layer. Finally, several field examples were presented to validate the effectiveness and applicability of the new method.

The Neutron-Porosity Logging Method Based on D-D Generator With Dual Pulse Mode in Sidetracking Well

Xiaoyang Zhang, Xuelian Chen, Hui Zhang, and Feng Zhang, School of Geoscience, China University of Petroleum (East China); Linhua Guan, Jingli Dong, and Qian Chen, Sinopec Matrix Corporation

With the increasing demand for oil and gas exploration, the reason for sidetracking an existing well is to restore or increase the production of an existing well quickly and economically. As basic reservoir parameters, porosity and oil saturation are essential for the real-time formation evaluation in sidetracking wells. Traditional neutron-porosity logging using an Am-Be neutron source and two He-3 detectors has been widely applied in oil and gas exploration. Thus, the Am-Be logging source has been replaced either with a D-T neutron generator or a Cf-252 source to reduce the potential for vulnerability to radiological dispersal devices (Badruzzaman, 2017). However, one of the problems from neutron-porosity logging using a D-T neutron generator and He-3 detector or gamma detectors is of low sensitivity in high-porosity formations. Due to a low neutron yield of only 5×10^6 n/s for a compact D-D generator, its application is limited by the need for fast measurement speed of wireline logging in open hole, which results in large fluctuations in cable logging. However, the D-D neutron generator can be used to measure neutron porosity and solve the low yield problem due to the slow speed of drill bits and long drilling and measurement times in sidetracking horizontal well technology for improving oil recovery.

In this paper, the thermal neutron porosity and oil saturation evaluating method using a D-D source could be studied in the sidetracking well. The fast neutrons with 2.45 MeV emitting from a D-D neutron generator elastically scatter the nuclear atoms in the formation, slowing them down into epithermal and thermal neutrons. In different formation-slowing capacities, the He-3 tube records thermal neutron counts at different positions from the neutron source, reflects the formation deceleration ability, and then determines neutron porosity. First, a dual pulse mode of the D-D neutron source is designed, and the thermal neutron count selected ranging from 0 to 1,000 μs is used for determining porosity. Response laws for apparent porosity and true porosity are obtained to compare detection systems using a D-D generator and conventional Am-Be source, particularly in formations containing heavy minerals and clay. Finally, using a time spectrum, the formation sigma is determined to identify water saturation. Since the porosity is affected by the hole size and fluid salinity, the first pulse information of the near detector is used for borehole self-compensation correction.

The Monte Carlo method was used to simulate the distribution of thermal neutrons using a D-D generator and Am-Be source under the condition of different boreholes and formations. The results showed the apparent porosity is measured with D-D and conventional compensation at about 1.5 p.u. for formations containing different clay. As for formations containing heavy minerals, since there are differences in heavy mineral type and content, the response laws are significantly different between thermal neutron capture ability. Therefore, a significantly higher porosity can reach approximately 3 p.u. measured using a D-D neutron generator than the true porosity. Compared with conventional compensated neutron-porosity logging with an Am-Be source in the same formation, heavy mineral content and clays have a relatively minimal effect on this porosity measure using a D-D neutron generator. According to the neutron life logging principle, the formation macro capture cross section is calculated by using the thermal neutron time spectrum of the double detector. After the diffusion effect correction, the rock volume physical model of the formation macro capture cross section can be established, and then the water saturation can be determined, which provides a basic means for real-time fluid evaluation in sidetracking well.

Use of Spectral Gamma Ray and Lithogeochemical Logs Combined With XRD Data to Identify Mg-Clay Mineral Sequences in Barra Velha Formation (BVE) – Lower Cretaceous of the Santos Basin
Paulo Roberto Alves Netto, Petrobras, and Manuel Pozo, Universidad Autónoma de Madrid

Natural radioactivity in rocks is usually the result of the presence of natural isotopes: potassium – ^{40}K, uranium – ^{238}U, ^{234}U, ^{235}U, and thorium – ^{232}Th and their decay products. Initially contained in acid igneous rocks, these isotopes are released through weathering processes and subsequently transported to sedimentary sites, where they primarily accumulate by adsorption onto clay mineral particles. Direct measurements of potassium, uranium, and thorium activity in sedimentary rocks provide crucial insights into their geochemistry and mineral content.

Methods proposed the use of gamma ray logs as lithological indicators in siliciclastic sedimentary rocks suggest that high gamma ray values indicate the presence of fine-grained deposits or those rich in clay minerals, while low values suggest coarse-grained rocks or carbonates. However, they are inconsistent in identifying deposits containing high concentrations of potassium-rich minerals. The ability to distinguish between the gamma emissions of uranium, thorium, and potassium means that the gamma ray spectral profile can be used to identify various clay minerals.

The use of this profile to identify minerals and clay minerals in a siliciclastic environment is well established for an assemblage composed of the main minerals found in these sedimentary environments (e.g., chlorite, kaolinite, smectite and its mixed layers, illite, micas, glauconite, and feldspar). However, for environments rich in Mg-clay minerals, this study has not yet been developed.

The concentrations of Si^{+4}, Mg^{+2}, and Ca^{+2} cation provided by the lithogeochemical logs and their ratios can efficiently indicate intervals rich in Mg-clay and the mineral species present after adjustments to their mineral model.

The aim of this work is to establish a methodology for identifying the clay minerals present in the rocks of BVE formation using gamma ray spectral and lithogeochemical logs on the base of samples where the Mg-clay minerals have already been identified using X-ray diffractometry (XRD) data.

The data analysis shows that samples rich in stevensite (> 95%), an Mg-smectite, are associated with higher thorium and uranium values and intermediate potassium values. The kerolite-stevensite interstratified samples occur at points with intermediate thorium values and lower potassium values but without a diagnostic behavior for uranium. Samples rich in kerolite (> 95%) are associated with lower potassium and uranium values and intermediate thorium values. Saponite-rich samples (> 95%), which is a Mg-smectite rich in Al^{+3}, are associated with lower potassium values and intermediate to low thorium values, showing dispersed behavior in relation to uranium. Samples with intercalation between saponite and kerolite behave more like kerolite, with low potassium and uranium values and intermediate thorium values.

In addition to XRD data for identifying Mg-clay minerals, total organic carbon (TOC) data can be incorporated to understand the variation in gamma ray values, especially the behavior of uranium at points with high TOC contents. The correlation of these values can shed light on the BVE lacustrine sedimentology.

SPORSE: MULTIPHYSICS/MULTIDISCIPLINARY CORE TO RESERVOIR MODELS: GEOLOGIC FACIES LINKED TO PETROPHYSICAL ROCK TYPES, HETEROGENEITY QUANTIFICATION, AND LARGE PORE PETROPHYSICAL MODELING

A New Method to Compute Formation Density and Pe Values With a Thru-Bit Density Tool

Yang Wang and Qiong Zhang, University of Electronic Science and Technology of China; Qiang Li, Beijing Xinyuan Huayou Tech Co. Ltd

Accurate formation density measurement is a fundamentally difficult problem due to the presence of mudcake in a borehole. This is especially so for thru-bit density tools whose detector crystals are smaller due to design constraints and, therefore, fewer formation signals are detected, adding more uncertainties to traditional density computation methods. It is difficult to quantitatively evaluate these uncertainties while maintaining proper thru-bit logging speed during the measurement process. Therefore, it is imperative to develop a new method that could effectively obtain thru-bit formation density and provide a reliable assessment of the environment free of mudcake effects.

In this paper, we propose a new method based on a detector response model derived from the underlying gamma physics of Compton scattering and the photoelectric effect. These detector models are designed to describe tool response as a nonlinear function of key physical and spatial parameters that impact density and Pe measurement, such as lithology, mudcake, etc. Each model is developed and calibrated through extensive Monte Carlo simulations representing varying logging scenarios in order to capture the detector's unique characteristics, such as depth of investigation, measurement sensitivity, etc. Specifically, detector response function is calculated and employed into the Monte Carlo framework to obtain precise responses pertaining to long- and short-spaced detectors separately. This proves very useful in improving the efficiency of forward calculation, given detector crystals are of smaller size on thru-bit tools and, therefore, require a higher level of accuracy in forward computation. For inversion, the constraint-based Quasi-Newton method is selected to minimize the system error and obtain the optimized solution. By employing all detector models into a parametric forward-inversion framework, it is feasible to obtain four unknowns: formation density, formation Pe, mudcake density, and mudcake Pe simultaneously.

The method is implemented on a newly designed thru-bit density tool and verified in test pits with different types of mudcake with and without barite. A density error of 0.015 g/cm^3 and a Pe error of 0.2 are obtained, verifying the correctness of the method. In addition, an example from a horizontal well in the low-permeability shale oil reservoir of Changqing oil field is presented to further prove the method is capable of correcting mudcake effects and achieving the correct formation density in challenging situations, thus helping unconventional reservoir characterization.

A Novel Multiphysics Interpretation Method for Quantifying Mineral Using a Pulsed-Neutron Element Logging Tool

Yi Ge and Qiong Zhang, University of Electronic Science and Technology of China; Ya Jin, Quanwen Zhang, Decheng Niu, and Lu Yin, China Oilfield Services Limited

In comparison to traditional radioactive sources, pulsed-neutron sources are controllable and can emit high-energy neutrons. The detection of neutron-induced gamma rays leads to the estimation of multiple formation properties, which include elemental concentrations derived through the analysis of gamma spectroscopy, enabling the quantification of mineral composition for complex reservoir evaluation. However, diverse geological regions are influenced by distinct diagenetic processes, resulting in complex and variable mineral compositions. Furthermore, there is a scarcity of well-labeled, high-quality mineral samples from different regions. Therefore, in situations characterized by a complex mapping relationship between elements and minerals and a limited sample size, a multiphysics novel interpretation framework suitable for few-shot learning has been employed. This framework is designed to address the challenges posed by small sample sizes and incorporates conventional logs such as porosity, density, and sonic logs to establish the relationship between elements and minerals accurately, facilitating the quantification of mineral concentrations.

The proposed method is founded upon the measurement of neutron-induced gamma energy spectra by a pulsed-neutron element logging tool, presenting a novel interpretation framework for quantifying both elemental and mineral concentrations. It composes two key steps: (1) Initially, resolution matching between standard spectra and measured spectra is achieved using a nonlinear optimizer. Subsequently, through a fusion of iterative and weighted least-squares methods, adaptive non-negative elemental concentration determination is realized. (2) Conventional well-logging curves such as density, neutron, sonic, and natural gamma, along with elemental concentrations, are introduced as inputs to the model. Additionally, the SMOTE data augmentation method is applied to address the issue of limited sample size, generating more data. (3) An advanced Transformer encoder-decoder is employed to establish high-dimensional nonlinear relationships among various minerals, elements, and conventional well-logging curves. Through self-attention mechanisms, it effectively represents continuous inputs at different depths, mapping them to mineral concentrations.

The proposed method has been validated in the complex downhole environments of Bohai and Shanxi, China. It successfully determined the concentrations of minerals such as quartz, feldspar, clay, calcite, dolomite, siderite, pyrite, and more. This method is applied to a well in the Bohai Sea, which contains complex metamorphic rocks, such as granite gneiss and biotite schist, with complex mineral composition. The mineral concentrations calculated by this method closely align with XRD results, affirming its reliability. In addition, this method has been effectively employed in deep coalbed wells to obtain the concentrations of minerals and TOC. Future work will concentrate on more complex reservoir evaluations in unconventional formations and will include comparisons with results from core experiments.

Best Practices for Porosity Estimation in Karstified Presalt Carbonate Reservoirs
Candida Menezes de Jesus, Frederico Bastos Schuab, Lucas Abreu Blanes de Oliveira, and Rodrigo Dos Santos Maia Correa, Petrobras

The dynamic impact of the extra matrix pore system in presalt carbonate reservoirs has been the driving force for the development of new techniques and workflows for their characterization. The presence of large-scale and high connectivity pore systems can affect several processes, from drilling and completion efficiency to flow modeling and history matching. Characterizing these systems requires a peculiar type of modeling that is based both on measurements and assumptions since the geometry of the pore network extends beyond the well, residing in an intermediate scale that cannot be fully measured on petrophysical logs nor on seismic data. However, borehole image logs detect the presence of this pore scale, not completely, but in the most representative way possible. Therefore, quantitative analysis of those structures based on borehole image logs became mandatory for projects targeting presalt carbonates. In these reservoirs, porosity and permeability models from the well to geocellular scale have been built, integrating attributes extracted from borehole image logs, conventional petrophysical log suits, routine core analysis, and permeability estimations based on drillstem test measurements. However, we observed that the traditional petrophysical logs used for modeling the matrix porosity partially detect the extra matrix pores system, even after they receive proper environmental corrections (Fig. 1). Therefore, the logs typically used to characterize the matrix effective porosity are consistently contaminated by a mixture of pore volumes that actually belong to different pore types and scales that would have distinct flow behavior.

Hence, in this study, we seek to carry out a comparative analysis of the different porosity logs acquired in presalt karstified carbonate sections, searching for means of isolating the extra matrix systems and characterizing the effective matrix porosity in a more precise manner. The most accurate way to do that appears to be by using the decomposition of the nuclear magnetic resonance (NMR) relaxation spectrum, which separates the mud signal detected in large cavities from the relaxation of the matrix pore volume. That is considered the best candidate to represent the matrix effective porosity. Conversely, the quantitative analysis of the borehole image logs must be used to represent the extra matrix porosity. By separating the effect of the mega and giga pores on the porosity logs, it is possible to model parts of the reservoir that are expected to behave as standard porous media and treat the large-scale pore system with different mathematical representations. A sensitivity analysis demonstrating the impact on VOIP was also performed on a three-dimensional (3D) model considering three scenarios: one with the ideal matrix porosity log, another one with the NMR porosity log contaminated by extra matrix pore volume, and another one considering the sum of ideal matrix porosity and the extra matrix porosity.

The extra matrix pores present on karstified reservoirs do not flow like traditional porous media, and they may have a significant impact on project scope and field productivity. Therefore, it is essential to represent these systems as accurately as possible. Using this approach, we intend to determine the best practices for representing the porosity in karstified reservoirs while separating contaminated and nonrepresentative measurements that these large-scale pores generate in direct porosity tool readings, leading us to more predictive models.

Developing a Novel Petrophysical Rock Typing (PRT) Classification Using Machine Learning Applied in a Supergiant Oil and Gas Field in Southern Iraq
Mohammed A. Abbas, Basra Oil Company

The utilization of petrophysical rock typing (PRT) through the analysis of core and well-log data is an advantageous technique for classifying reservoirs and estimating recoverable reserves in heterogeneous multimodal pore carbonate systems. Nevertheless, the conventional PRT techniques frequently exhibit limited efficacy in such systems because of the complicated pore structure and distribution. This research paper introduces an innovative approach to PRT classification in a complex carbonate reservoir of a supergiant oil and gas field located in southern Iraq. The proposed method leverages advanced machine-learning algorithms to attain accurate classification results.

The proposed methodology initially uses Ward's hierarchical clustering technique to analyze the capillary pressure and pore-throat radius distribution curves obtained from the mercury injection capillary pressure (MICP) special core analysis data, with the purpose of characterizing the PRT. Ward's approach successfully detects five separate clusters, each representing a distinct petrophysical rock type characterized by unique pore geometry and system. The utilization of the probabilistic neural network (PNN) methodology is then employed to categorize the PRTs based on well-logging data obtained from a cored well.

The well-log interpretations encompass a range of measurements, including caliper, gamma ray, neutron, bulk density, sonic transit time, deep resistivity, shallow resistivity, total porosity, and water saturation, along with the conventional core analysis of porosity, permeability, and lithofacies distribution. The PNN algorithm demonstrates the capability to acquire knowledge about complex nonlinear associations between well-logging data and characterized PRT. Moreover, it reveals a remarkable ability to predict precisely PRTs. The efficiency of the PNN classification algorithm performance was analyzed using the confusion matrix and the total correct percent (TCP) as supplementary criteria. The findings of the study indicate a strong agreement between the predicted and observed PRT, with a TCP of 94% for the testing subset and 95% for the total data set.

The findings of this study demonstrate that the suggested PRT approach exhibits a notable capability to accurately categorize PRT among diverse multimodal pore carbonate systems. The methodology can be readily extended to different reservoirs, hence offering the opportunity to enhance the comprehensive characterization of reservoirs. In the subsequent phase of this project, the predicted PRT distribution is employed as a supplementary autonomous variable to enhance the regression of core permeability and the modeling of saturation height function, therefore attaining a geologically plausible distribution.

Digital Rock Physics for Geomechanics – Examples and Challenges Ahead
João Paulo Pereira Nunes, Petrobras

Digital rock physics is a technology that generates the physical properties of a porous medium via numerical simulation on tomographic images of rock samples, whether they are sidewall cores, plugs, or core samples. Typically, it is employed for the characterization of single- or two-phase flow: permeability, relative permeability, and capillary pressure. However, it is also possible to obtain elastic moduli and more general mechanical properties, such as plastic behavior or the identification of damaged regions. In comparison to conventional (laboratory) methods, digital rock physics (DRP) offers several advantages: (1) a multiscale approach (from pore to core), (2) properties obtained on the same basis, where a single sample can be used for both SCAL and mechanical characterization, (3) the use of small samples that would not be suitable for geomechanical testing, and (4) a quick turnaround time for delivering results.

In this presentation, we will detail these advantages and provide examples of the use of DRP in the mechanical characterization at the core scale of karstified reservoirs. Next, we will illustrate the hydraulic and mechanical characterization of deformation bands (localized deformation zones in porous sandstones) in a turbidite reservoir. We will illustrate how laboratory tests can be combined with computational simulations to estimate the impact of deformation zones on the effective properties of deformed cores. We will also discuss an example of assessing the hydraulic behavior of a gas reservoir subjected to depletion and compaction.

To conclude, we will provide a summary of ongoing research activities at Petrobras and an overview of industry trends in the use of digital petrophysics for geomechanics and rock physics. This talk will bring examples of actual field applications of digitally generated geomechanical properties, which have successfully contributed to the understanding of the mechanical behavior of both sandstone and carbonate reservoirs.

Innovative Igneous Rock Presalt Classification Method via TAS Workflow, Well-Log Clustering, and Sidewall Core Analysis

Jeniffer Alves Nobre, Danilo Jotta Ariza Ferreira, Bruno Neves Macedo, and Adna Grazielly Paz de Vasconcelos, SLB

The complexity of the lithological facies in presalt reservoirs is well known, especially since igneous rocks may occur within these carbonate reservoirs. Therefore, it is extremely important to characterize these volcanic bodies as well as their distribution in the study area. Also, igneous rocks classification can provide valuable support for understanding diagenetic processes as well as acting as chronostratigraphic markers assisting in well correlation. However, the frequent unavailability of mineralogical data for all wells within a presalt field can pose a significant challenge in discriminating the different types of igneous rocks. This study proposes an innovative workflow for the characterization of igneous rocks in presalt intervals, which combines an adaptation of the total alkalis vs. silica (TAS) classification with unsupervised K-means facies clustering, maximizing the data available and allowing igneous rock analysis even for wells with basic well-log suites.

Our methodology was developed and applied in three wells from a presalt field, two of which contained spectroscopy logs, and one well had a basic set of well logs and rock samples. TAS classification grounded in rock chemistry was applied to Wells 1 and 2 and considered various relationships, such as the Na_2O to K_2O ratio, the amount of K_2O, the Al_2O_3 to FeO ratio, and the ratio of different normative minerals for igneous rocks classification. Later, the K-means technique was adopted for unsupervised zoning of volcanic facies in all wells and corroborated by TAS analysis for Wells 1 and 2 and rock samples from Well 3. The gamma ray (GR), density (DENS), and neutron (NEUT) logs from Wells 1, 2, and 3 were selected as input data for K-means clustering after conducting various tests using different combinations of well logs.

As a result of the TAS workflow, significant variation in the volcanic facies was observed, as indicated by both the diagram and the normative mineralogy curve (Fig. 1a). The volcanic rocks in Well 1 were predominantly classified as basic to intermediate, with moderate to high levels of Na+K. The normative mineralogy curve for both Wells 1 and 2 reveals the prevalence of certain minerals, such as quartz, orthoclase, albite, and diopside, among others, in varying proportions throughout the well. Comparing the normative mineralogy curves of Wells 1 and 2, we observed higher levels of quartz and ilmenite in Well 1, which are rarer in Well 2, and on the other hand, there is the majority presence of the mineral larnite and higher pyrite and wollastonite content in Well 2. Also, in Well 2, there were intervals classified as ultrabasic rocks with Na+K values below 0.05 w/w, indicating rocks richer in Mg. From the K-means results, six clusters were obtained (Fig. 1b). Only Cluster 4 was common to all wells, enabling correlation between the wells in a basic to intermediate extrusive rock event (Fig. 1b) and the extrapolation of volcanic facies classified via TAS diagram. Another interesting result obtained was the correlation between the variation in composition and consequently the type of mineral alteration described in the SWC with clustering via K-means, mutually responding to the depositional evolution of these volcanic rocks (Fig. 1c). Therefore, with the development of new methodology combining the TAS workflow with K-means clustering, we obtained a comprehensive assessment of the three wells igneous characteristics effectively discriminating different igneous rock types that also allowed the identification of a chronostratigraphic marker.

Mechanical Properties of Carbonate-Rich Mudrocks Through the Coupling of Microindentation, Acoustic Microscopy, SEM Imaging and Image Analysis, and Elemental Analysis With Emphasis on the Cement Phases Present

Ajibola Olalekan Samo, Lori Hathon, and Michael Myers, University of Houston

Mudrock reservoirs exhibit highly variable geomechanical properties that depend on factors such as clay mineral and organic matter content, compaction state, and degree of cementation. The effectiveness of hydraulic fracturing in mudrock reservoirs relies heavily upon these mechanical properties. While the influence of authigenic silica cement in enhancing the brittleness of certain unconventional reservoirs (e.g., the Barnett Formation) is well documented, the role of authigenic carbonate cement in enhancing brittleness in carbonate-rich reservoirs and the geochemical signals associated with it are relatively understudied. Understanding the distribution of carbonate cement in calcareous and argillaceous shale reservoirs and its relationship to acoustic and geomechanical properties can enhance reservoir performance through better frack placement.

A prior study illustrated that Sr content could serve as a proxy for the identification of authigenic carbonate cements in calcareous reservoirs such as the Eagle Ford and Niobrara Formations. In contrast, for argillaceous shale reservoirs, such as the Haynesville Formation, carbonate cements are associated with enrichment in Fe-Mg-Mn relative to a background shale. Thus, geochemical proxies can be used to identify the presence of carbonate cement in shale reservoirs of varying lithology.

This study combines classical grid microindentation techniques with backscattered electron imaging and elemental mapping using energy dispersive X-ray spectrometry (SEM-EDS) and C-mode scanning acoustic microscopy. High-resolution (lamina scale) compressional velocities and elemental analysis for all phases are measured over the indentation region and mapped over the indentation points. Elemental composition, authigenic vs. detrital phases, porosity, TOC, clay content, indentation hardness, modulus, and velocities are considered in a cluster analysis within the framework of finite mixture models with a Gaussian component density function.

The method successfully develops a relationship between the dynamic and static properties of mudrock laminae as a function of varying volumes of carbonate cement, TOC, clay minerals, and porosity. The lamina-scale velocities and strength properties are then used to estimate plug-scale properties. Those estimates are compared to plug-scale measurements of acoustic and strength properties made on “twin” samples.

Although nano- and microindentation studies have been performed previously on unconventional reservoirs, this is the first study that relates lamina-scale static and dynamic properties measured on the same volume. In addition, the use of geochemical proxies for the identification of authigenic carbonate phases, as well as detailed image analysis quantifying clay content, TOC, porosity, and the volume of authigenic phases, allows us to build predictive models for acoustic and strength properties.

Multi-Technique Characterization of Carbonate Lithotypes and Evaluation of the Impact of Fine Grains on Barra Velha Formation Reservoirs, Sepia Field, Santos Basin

Guilherme Santos, Petrophysics Laboratory of National Observatory (LabPetrON/ON); Gabriel Ribeiro, Advanced Oil Recovery Laboratory (LRAP/UFRJ); Leonardo Ventura Andrade de Souza and Giovanni Stael, Petrophysics Laboratory of National Observatory (LabPetrON/ON)

The presalt section of the Santos Basin is responsible for around 73% of Brazil's oil production. Previous studies have identified the significant presence of fine grains negatively affecting the petrophysical properties of the Barra Velha Formation in the Buzios Field. With the help of well and rock data, these studies highlight the impact of magnesian clays on the quality of reservoir rocks. These Mg clays are prone to dissolution during diagenesis and can result in regions with high-porosity values. However, they can also occur and be distributed as laminated structures associated with the carbonates of Barra Velha Formation. As they do not contain radioactive elements, it is a challenge to identify them using conventional petrophysical evaluation methods. In this research, we propose the petrophysical evaluation of carbonate rocks in the presalt section of the Sepia Field, Santos Basin, with a view to identifying the best reservoir zones in two neighboring wells and correlating them to obtain a more robust characterization of the reservoir, in addition to verifying the influence of magnesian clays and understanding the relationship between the preservation of these clays in the rocks and the impact of reservoir properties such as porosity and permeability.

The evaluation of Barra Velha Formation made it possible to estimate the petrophysical properties, interpret the lithotypes, and obtain the associated elastic parameters using data from well logs. From well data, it is possible to analyze the sensitivity for a possible quantitative seismic interpretation. Rock physics crossplots allow us to correlate elastic parameters with reservoir properties, helping to reduce uncertainties. At this stage, the effective porosity (PHIE) and density (DENS) curves were obtained from the well logs, as well as the vagarosity curves used to calculate the compressional wave velocity (VP), shear wave velocity (VS), and acoustic impedance (AI) curves.

The AI vs. PHIE (Fig.1a) and AI vs. DENS (Fig. 1c) crossplots made it possible to identify three distinct main trends: reservoir carbonates, muddy carbonates, and tight carbonates. In contrast, the attempt to visualize the same separation using the VP/VS ratio vs. AI crossplot (Fig. 1b) was unsuccessful. In the main trend, the increase in AI is related to the decrease in PHIE in both wells. The best reservoir zones are associated with lower AI values and medium to high porosities. The tight carbonates stand out for their high values of AI and a considerable decrease in porosity due to the influence of diagenetic processes of cementation and compaction. Muddy facies are associated with the lowest AI values, while porosity remains slightly altered. The VP/VS ratio vs. AI crossplot shows that the muddy zones have high VP/VS values, higher than in the tight zones, but not enough to separate them from the reservoir zones. As an option, the AI vs. DENS crossplot shows good separation between the three lithotypes, indicating an increase in impedance related to denser zones with lower reservoir quality. The fact that the muddy carbonates exhibit porosity may contribute to relatively lower DENS values than the tight carbonates but still higher than the reservoir zones. Therefore, ranges of close AI values derived from acoustic inversion can lead to misinterpretations about high porosities in both wells. Therefore, using these crossplots (AI vs. PHIE, VP/VS ratio vs. AI, AI vs. DENS) together is essential to visualize the influence of magnesian clays and understand the heterogeneities of the carbonates in the Barra Velha Formation.

Static-to-Dynamic Permeability Ratio Provides Valuable Insight of Reservoir Architecture and Heterogeneity in Complex Hydraulically Fractured Reservoirs

German Merletti, Siyavash Motealleh, Peter Armitage, Salim Al Hajri, Khalil Al Rashdi, Martin Wells, and Nigel Clark, BP

Matrix permeability is a key parameter to predict reservoir deliverability and ultimate recovery in tight gas reservoirs. Since it is a multiscale property, its values can significantly change with the scale of the medium under investigation. Well-log evaluation and core measurements provide pore- to meter-scale static measurements exclusively representative of the borehole vicinity, whereas well testing provides kilometer-scale dynamic permeability under multiple assumptions such as rock and fluid properties. This paper demonstrates how discrepancies between static and dynamic calculations of reservoir permeability present an opportunity to validate models of reservoir quality and lateral connectivity away from boreholes. The lack of a simple relationship between static and dynamic permeability is a valuable observation to help understand reservoir architecture and to promote multidisciplinary integration.

The process starts with the assessment of static permeability (at the borehole); we used extensive sedimentary and petrographic data to quantify the effects of depositional facies, mineral composition, and diagenetic overprint on porosity-permeability functions. This permeability model was compared to machine-learning (ML) permeability calculated from wireline logs to provide additional consistency checks and coverage in areas where core was unavailable. Absolute permeabilities were converted to effective permeability using unsteady-state relative permeability testing.

The primary source of dynamic permeability is pressure transient analysis (PTA) from pressure buildup tests in shut-in wells. Over 20 wells with tests achieving radial flow provided validation for gas-effective permeability thickness. Since PTA does not densely cover the field, we used rate transient analysis (RTA) from over a 100 wells to derive a pseudo-PTA permeability. This approach included the calculation of original gas in place (OGIP), which is the most reliable parameter from RTA, using a flowing material balance (FMB) and then corroborated results by type curve analysis. We finally derived correlations between PTA-derived permeability and RTA-derived OGIP as an additional proxy for dynamic permeability in wells with more than 6 months of production.

The ratio between dynamic and static permeability provides valuable insights into reservoir architecture and heterogeneity away from boreholes. Ratios below unity reflect the preservation of interbedded thin mudstones, which provided silica to occlude pore space and throats of nearby sandstones with quartz cement during diagenesis. Mudstones and cemented sandstone shoulders provide additional tortuosity that greatly reduces connected gas volumes identified by transient analysis. Ratios above unity represent fewer preserved mudstone layers and overall better sandstone quality; even though the sandstone thickness can be lower, the dynamic permeability and connected volumes are consistently larger. Lower gross thickness is associated with less accommodation space in the proximity of basement highs. This setting promoted the removal of interbedded mudstones (and associated damaging effects on reservoirs) and boosted reservoir lateral connectivity. The understanding of dynamic and static permeability ratios and their linkage to the diagenetic overprint on depositional architecture contribute to identifying undeveloped resources (i.e., infill drilling) as well as better prediction of initial reservoir performance in new wells.

SURFACE DATA LOGGING – ROCK AND FLUID ANALYSIS

LiOBIA: Object-Based Cuttings Image Analysis for Automated Lithology Evaluation

Tetsushi Yamada, Simone Di Santo, Karim Bondabou, Laura Su, and Romain Prioul, SLB

Drilled cuttings from wells are useful physical sources of information to describe the underground geological properties for formation evaluation. While the process of cutting analysis and description is known to be labor and expert intensive, there have been efforts in the industry to make this process less human dependent using digital images, benefiting from the recent advances in computer vision, machine learning, and computational infrastructure. In our initial work, we proposed a workflow based on object-based image analysis (OBIA), where a basic processing unit is a cutting instance as opposed to pixels or sliding windows. To demonstrate the feasibility of this workflow, we showed that a well-trained deep neural network model can efficiently segment cuttings even when they are piled. The key challenge in lithology type estimation is the visual variety; it is known that different types of lithology might look very similar or almost identical on the standard optical image. We accordingly designed our workflow to handle scenarios with different levels of geological complexities. In this paper, we revisit our initial workflow, thereafter LiOBIA (Lithology OBIA), to illustrate some of the key computational components enabled by machine learning and computer vision techniques and evaluate the results using a known cutting sample set and cuttings from two wells in Australia.

After a sequence of sample preparation procedures, we take high-resolution images of the cuttings in a calibrated system. Our workflow starts with the cutting instance segmentation. Then, the segmented cutting instances are streamed into two image processing pipelines: measurement and estimation. In the measurement pipeline, we compute their shape (e.g., roundness and elongation), size, and color properties, as well as image textural homogeneity. The estimation pipeline is composed of multiple steps. First, color and texture features are extracted from each cutting instance, which is represented by a multidimensional feature vector. Second, similar images are retrieved from the reference data set that is prelabeled or updated during the analysis. Third, the probabilities of the properties, such as lithology types, are computed from the retrieved reference images. We also define “unknown” and “uncertain” categories based on the distance and the probability. Furthermore, we constrain the predictable classes based on external information such as the local geological context from offset well data, mineral fluorescence, calcimetry, and acid test of cuttings to provide geology-informed outputs.

First, we evaluate the extracted features using a known cutting sample set from five lithology types (limestone, dolostone, sandstone, siltstone, and shale). The cutting instance images are plotted in a two-dimensional (2D) map based on extracted multidimensional features. Our visual evaluation confirms that the visually similar cutting instances are close to each other on the map. We also run a classification using the extracted features that shows an accuracy of 90%. The confusion matrix shows that the largest classification error is between limestone and dolostone, which makes geological sense because they are both carbonate rocks. Second, we apply our workflow to two wells from Western Australia: Iago and Wheatstone. The measurement properties, such as shape and color, are computed in a fully automatic manner. The estimated lithology types mostly correspond to the expert evaluation and are further improved thanks to the added geological constraints. We also estimate petrophysical formation properties using cuttings based on visual similarities and external information. We demonstrate successful cases, discuss the limitations, and propose potential improvements to our workflow.

MICP-Based Petrophysical Classification of Complex Carbonate Reservoir Rocks
André Luís Fernandes da Silva de Souza and Rodolfo A. Victor, Petrobras; Fábio A. Perosi, Universidade Federal do Rio de Janeiro

Carbonate reservoir rocks present highly heterogeneous pore structures due to their growth by mineral precipitations and diagenetic alterations. The resulting rock matrix properties, such as capillary pressure, porosity, and permeability, control the recoverable hydrocarbon storage, distribution, and flow mechanisms. In this work, we investigate the pore geometry in microscale to mesoscale and its control over the absolute hydraulic permeability. We examine different carbonate matrix facies in the Barra Velha and Itapema formations, both in the presalt Aptian section of the Mero Field, located at the ultradeep waters of Santos Basin, Brazil. The gathered data comprises 50 core rock samples with laboratory measurements of mercury injection capillary pressure (MICP), porosity, and permeability from routine core analysis and descriptions of petrographic thin sections. We also use 15 oil/water porous plate capillary pressure curves and associated electrical properties to assess irreducible water saturation, besides a complete suite of wireline well logs for petrophysical upscaling.

We propose a nonlinear least-squares fit of a multimodal Weibull function to the MICP data by implementing the Levemberg-Marquardt algorithm. We, then, petrophysically interpret the multi-Weibull parameters and compute the absolute hydraulic permeability using these adjusted function parameters and Kozeny-Carman equations. By comparing the MICP-based absolute permeability to the corresponding lab-measured data and respective petrographic thin sections, we were able to perform quality control on the MICP results and detect the nonrepresentative measurements. We then use the

MICP-based permeability to perform rock classification through Lucia's rock fabric and Amaefule's flow zone indicator methods, further improving these classification schemes with depositional and diagenetic properties from the thin sections, finally establishing a link between pore-scale properties and geological characteristics. This information can be used for later petrophysical upscaling and reservoir modeling.

We developed a semi-automated analytical model well suited to characterize complex carbonate matrix reservoir rocks, delivering multiple cross-correlation charts and matrix-correlation tables and associating multiple geological and petrophysical properties. Our approach also allowed for detecting anomalous data, providing a way to quality control experimental results, therefore enhancing the petrophysical characterization from multiple data sources. The multi-Weibull inversion was shown to be highly versatile in modeling several non-symmetric pore-throat distributions, accurately probing porous volume partitioning, and properly detecting the length scales controlling permeability, mercury entry pressure, and fluid saturation. Our new method calculates MICP-based absolute hydraulic permeability with higher accuracy by using the multi-Weibiull model parameters and Kozeny-Carman equations. Correlation of petrophysical and geological properties from petrographical thin sections with our multi-Weibull models and classification through Lucia's rock-fabric and Amaefule's flow zone indicator methods led to a better comprehension of how depositional and diagenetic textures control the microscopic fluid flow inside the reservoir. The reservoir rock classification revealed that the rocks under analysis are well represented by general porosity-permeability trend lines of Lucias' rock fabric numbers. Hydraulic flow units revealed strong correlations to characteristic pore-scale dimensions and to post-depositional diagenetic alterations, controlling the absolute hydraulic permeability behavior.

Optimize Drilling Decisions Based on Real-Time Detected Alkene and Hydrogen at Surface
Amjad Kharaba and Khalid Qubaisi, Saudi Aramco; Richard Hewitt and Milton Sanclemente, Rawabi Geolog

The "bit burn" effect occurs when drilling efficiency decreases due to bit wearing, and therefore frictional effects increase. The increase of these frictional effects generates high temperatures, and unsaturated hydrocarbons and hydrogen start to be generated due to thermal cracking. Integrated analysis of alkenes (ethylene and propylene) and hydrogen artificially generated downhole with drilling parameters and saturated hydrocarbon data would refine the analysis for real-time monitoring of bit condition and, hence, drilling efficiency.

Optimized extraction techniques are used to obtain a steady flow of gas at a constant volume and temperature from the flowline. The concentration of these artificial gases is measured in real time as well as naturally occurring saturated hydrocarbons using three different chromatographs, two of them having optimized adapted columns allowing the separation of the different gasses. This is especially critical in the case of ethylene and propylene and their respective saturated counterparts. Finally, dedicated software allows integration with drilling parameters to determine any decrease in drilling efficiency.

Real-time advanced gas detection (alkenes and hydrogen) was used while drilling. Integrated real-time advanced gas readings (alkenes and hydrogen) have been compared to the standard gas chromatography composition (methane-through pentane) measured at the same time. The correlation between the trends from the two techniques was clearly identified. Data interpretation demonstrated evidence that hydrogen and unsaturated hydrocarbons presented across some drilling sections are not naturally occurring but a product of bit metamorphism. The origin of this cracked gas throughout the reservoir section has been confirmed by bit grading at surface, with high bit wear confirmed. This kind of analysis can provide an enhanced tool to estimate bit wear and optimize drilling costs in real time and avoid potentially substantial NPT that can arise from prolonged drilling with a worn bit. The method is low risk and cost effective, as it is not necessary to use any downhole tools, and all data can be provided by equipment already present in advanced mudlogging units.

Reservoir Fluid Properties From Cuttings: An Innovative Synergy of Gel Permeation Chromatography and Data Analytics

Alexandra Cely, Equinor ASA

Drilling cuttings, often employed for lithology and mineralogy analyses, hold untapped potential. Extracts from cuttings are valuable in traditional geochemical analysis, particularly in water-based mud applications. On the other hand, the scarcity of reservoir fluid samples from reservoir zones and overburden presents a challenge, withholding from us vital insights crucial for well integrity, plugging and abandonment (P&A), and efficient reservoir management and production. Paradoxically, numerous drill-cutting samples remain unexamined within storage facilities.

After an intensive two-year research effort focused on developing an innovative gel permeation chromatography (GPC) technique for the analysis of cutting extracts, we have achieved a significant milestone. Our innovation facilitates the in-depth examination of reservoir fluid properties, i.e., density and viscosity, from cutting samples, effectively overcoming challenges associated with the presence of oil-based mud contamination.

In this study, we investigate the application of GPC coupled with both ultraviolet (UV) and infrared (IR) detectors to generate multidetector spectra from cuttings extracts and reservoir fluids originating from six distinct fields situated in the Norwegian and United Kingdom continental shelves. The technique is employed in the analysis of over 30 samples, encompassing a wide range of reservoir fluid types, including condensates, volatile oils, black oils, and heavy oils. The primary goal of the study is to estimate reservoir oil density using GPC-UV-IR spectra from cuttings.

Following the acquisition of GPC spectra, the data are compiled into a vectorized data set for subsequent processing in a data analytics workflow. This data processing phase comprises exploratory data analysis and quality checking, data augmentation, and machine-learning modeling, which serves as proof of concept of the application. In this phase of the study, a suite of machine-learning algorithms, including regularized linear regression and instance-based models, are evaluated. Furthermore, a comprehensive comparison of performance, generalization capability, and robustness of the baseline models and the augmented models are also discussed. The developed models demonstrate a remarkable level of accuracy in predicting reservoir fluid properties, specifically °API (American Petroleum Institute gravity) and viscosity.

Fundamentally, this technology transforms each drill-cutting fragment into a PVT (pressure-volume-temperature) sample and contributes significantly to unlocking the latent value within the cuttings, which are readily available and offer access to reservoir fluid properties at an early stage in field development, including the drilling phase. The application of the technology is not only cost effective but also carries far-reaching implications that extend into various areas, such as strategic well placement, enhanced wellbore integrity, and optimized completion strategies. In summary, this innovation marks a significant step towards maximizing value creation in exploration and production operations.

Using Machine Learning to Improve Rock Mechanical Properties Estimation: Correlating UCS From Scratch Test and Geophysical Loggings

Francisco Henriques Ferreira, Paulo Fernando Villafane Garcia, Anselmo Machado Borba, and Flavia de Oliveira Lima Falcao, Petrobras

Knowledge of rock mechanical properties associated with the in-situ stress state is fundamental to defining a mechanical earth model (MEM). Additionally, underground geometry plays an important role in the model. Depending on the structural problem under analysis, a MEM can be one-dimensional (1D) or three-dimensional (3D). Once a MEM has been assembled, studies of reservoir compaction, surface subsidence, fault reactivation, caprock integrity, sanding onset, hydraulic fracture design, and wellbore stability, among others, can be performed, although predicting strength and deformability properties from reservoir rocks can still be a challenge. Routinely, those are determined through lab tests and/or by association of empirical correlations and electrical logs. Both methods present drawbacks, however. Lab tests are costly and time consuming, while empirical correlations from literature, in general, are not entirely suitable for the formation under analysis. The index testing of rock, named “scratch test” (ST), consists of creating a narrow groove (10 mm) along the whole core using a hard bit. The normal and shear forces applied to create such indentation are registered, thus allowing for the estimation of unconfined compressive strength (UCS) and friction angle of the tested rock core. As core strength properties can be estimated in each millimeter of the tested core, thousands of rock mechanical properties are available by the end of a typical ST; the exact amount of information depends on the core length. Electrical logs such as compressional wave transit time, porosity, and density are frequently used to estimate rock mechanical properties. This amount of information indicates that machine-learning techniques should be applied to determine rock mechanical properties associated with ST and logs data. Frequently, the logged interval is larger than those submitted to ST; afterward, it is possible to upscale ST data for the whole reservoir height.

After a detailed screening of ST data, considering right, right but not representative, and outlier points, ST registers can be used along with log information to perform a neural network (ANN) fitting. A crucial part of the screening is to take into consideration the offset between driller-measured depth and log-measured depth in order to synchronize information from log and ST. This screening process is time consuming and must be performed carefully to guarantee a reliable ANN adjustment. A MATLAB program has been developed to accelerate the screening process. After data cleanup and ANN calibration, a parametric function is available, and then, it is possible to estimate rock mechanical properties for the whole reservoir where electrical logs are available.

In a Petrobras giant field in a presalt area, approximately 1,500 m of cores were cut in 18 wells and submitted to an ST. After cleaning ST registers and taking into account information from logs, an ANN was calibrated, and a parametric function was established, thus allowing researchers to estimate rock strength properties for the whole reservoir. The following figure schematically shows the ANN utilized in this study and results obtained from a trained ANN for one well of the aforementioned field. The applied methodology achieves a parametric function with a very high correlation coefficient, allowing for the estimation of UCS in reliable bases for the reservoir limestone. Additionally, the results from the calibrated ANN were compared to outcomes from empirical correlations found in the literature. ANN predictions proved to be more reliable than those from empirical correlations.

LATEST INNOVATIONS IN ULTRADEEP AZIMUTHAL RESISTIVITY FOR 3D APPLICATIONS

A New Short Source Distance Transient Electromagnetic LWD Tool for Geosteering and Formation Evaluation

Xiaozhuang Wang, Jie Gao, and Shizhen Ke, China University of Petroleum-Beijing; Jun Zhu and Zhanshan Xiao, China National Logging Corporation; Wei Su and Yanxin Zhou, China University of Petroleum-Beijing

Ultradeep electromagnetic (EM) resistivity logging-while-drilling (LWD) tools have been widely used in geosteering and reservoir mapping. The ability to detect formation information within the depth range of several meters to tens of meters in front of the drilling instrument can effectively optimize the well trajectory and improve reservoir exposure in oilfield development. In order to increase the detection depth, frequency domain ultradeep EM LWD tools need to reduce the signal frequency and increase the length of the instrument, which pose challenges to the inversion of thin layer formation information. In contrast, The LWD tool developed based on the transient EM principle can overcome the technical limitations of the frequency domain ultradeep detection. The short source distance structure is conducive to optimizing instrument design and improving the accuracy of formation information inversion.

A new transient EM LWD tool is introduced, adopting a combination of orthogonal transmitting and receiving antennas with a source distance of 1 m. A negative step pulse is applied in the transmitting antennas, and the receiving antennas measure the induced electromotive force with time. The time-domain logging signal contains rich stratigraphic information. The relationship between principal components and cross-components in the later time is used to extract accurate inclination information. The all-time apparent resistivity inversion algorithm can invert formation resistivity information in the time domain and obtain a formation resistivity profile that varies with logging depth. In order to accurately invert the formation interface information, innovative methods are used to extract more accurate interface response starting times from the interface scattering field, which enable the instrument to have a precise geological guidance function.

Compared with existing ultradeep detection logging tools, the new transient EM LWD tool mainly has three advantages: (1) The received signal is the secondary field in the wide frequency domain generated during the excitation source turn-off, and the lower-frequency signal is conducive to the realization of ultradeep detection; (2) The logging response is less affected by the source distance, and the instrument structure with short source distance has better resolution for thin layers; (3) Accurate time-domain logging responses can be obtained with any well inclination angle and favorable resistivity contrast conditions. The instrument can systematically obtain formation resistivity, well inclination angle, and formation bed boundary information.

Through the forward and inverse simulations and tests under different formation model conditions, the new transient EM tool can accurately determine the position of the formation interface above 30 m and combine the well inclination information to realize the optimization and adjustment of the real-time wellbore trajectory, which can reduce the risk of sidetracking, and provide accurate geological steering functions. Further, making full use of the retrieved formation resistivity information and combining it with other logging data can complete the refined reservoir interpretation and evaluation.

Adaptive Multidimensional Inversion for Borehole Ultradeep Azimuthal Resistivity
Wardana Saputra and Carlos Torres-Verdín, The University of Texas at Austin; Sofia Davydycheva and Vladimir Druskin, 3D EM Modeling&Inversion JIP; Jörn Zimmerling, University of Uppsala

Over the past two decades, significant progress has been made in the development of borehole ultradeep azimuthal resistivity (UDAR) measurements. However, the rapid and accurate inversion of UDAR measurements across heterogeneous/anisotropic subsurface formations still remains elusive. The typical UDAR interpretation that is commercially available relies on the simplifying assumption of a one-dimensional (1D) curtain-type representation of the subsurface distribution of electrical conductivity/resistivity along the well trajectory, often leading to inaccuracies in inversion results. On the other hand, higher-dimensional UDAR inversions are extremely expensive for real-time evaluation due to the significant computational costs of numerical forward simulations and remain strongly non-unique and unstable due to the exponential growth of the number of unknowns. In this study, we develop a new procedure for adaptive multidimensional inversion of UDAR measurements to reduce computational complexity without compromising the accuracy and reliability of results.

We implement an adaptive OCCAM algorithm that is fast and stable for approaching the nonlinear inversion of UDAR measurements. The procedure starts with a zero-dimensional (0D) inversion to estimate homogeneous background resistivities along the borehole trajectory with rapid analytical solutions. At every logging point, when model uncertainty is low, and data misfit is lower than measurement noise, we stop and take the 0D inversion result as the final solution. Otherwise, we use the 0D inversion result as a prior for the 1D curtain inversion with semi-analytical solutions of piece-wise layered structures. Similarly, we evaluate the locations along the well trajectory where both data misfit and model uncertainty are still relatively high; then, we perform higher-dimensional inversion locally across these segments. To reduce the computational time of two-dimensional (2D) and three-dimensional (3D) inversions, we substitute the numerical forward solutions with an approximation function that is at least two orders of magnitude faster; additionally, we apply Anderson’s acceleration, which increases the convergence rate of inversion. Finally, we adopt a total variation regularization strategy that helps to produce sharper results than the traditional OCCAM algorithm, thereby enhancing the accuracy of inversion results.

We tested the developed multidimensional inversion approach on synthetic UDAR measurements from a field-inspired reservoir model by invoking commercial UDAR tool configurations. 0D inversions performed on this data set only took 0.5 seconds for all 500 logging points on a typical PC with eight cores. We observed that data misfits were high along most of the well trajectory; therefore, we further performed 1D curtain inversions. With the same machine and number of logging points, 1D inversion runs in less than 50 seconds. The resulting data misfits are significantly reduced to the measurement noise level, except near the locations of normal faults, which exhibit non-1D behavior and become the sole candidates for higher-dimensional inversion. Using parallel computing, it took about 2 minutes to perform a 2D inversion in which the results revealed better fault structures with reduced data misfit and model uncertainty. To our knowledge, this is the first technical paper that highlights the significance of adaptive multidimensional UDAR inversion to progressively decrease data misfit and model uncertainty when triggering higher dimensions in the description and estimation of the subsurface resistivity distribution. We show that our inversion approach is fast, robust, and flexible for solving complex multidimensional distributions of anisotropic subsurface resistivity. Using priors from lower-dimensional inversion results helps to stabilize the inversion and reduce non-uniqueness, especially in 2D and 3D inversions. The method is being tested on field data, and the results obtained thus far verify favorable outcomes. Real-time 2D and 3D UDAR inversions are possible by combining our inversion approach with faster 2D and 3D forward simulations.

Enhanced Reservoir Characterization and Horizontal Well Placement With the Use of High-Definition and Three-Dimensional Reservoir-Mapping-While-Drilling Systems in Campos Basin, Offshore Brazil

Antonio Mainieri Vieira da Cunha, Caio Coutinho, Joao Antenor, Abel Hermida, Eduardo Mezzomo, Fabio Pimenta, Munir Koosar, and Elisangela Pessoa, Petrobras; Guillermo Marcelo Cuadros, Ligia Naia de Matos, Charles Silva, and Mauro Viandante, SLB

For more than 13 years, the optimization of horizontal well placement in the reservoirs of the Brazilian Campos Basin has significantly benefited from the use of reservoir-mapping-while-drilling (RMWD) technology. This technology enables proactive geosteering while enhancing reservoir characterization. It is based on ultradeep azimuthal resistivity measurements and employs a stochastic inversion algorithm to provide a resistivity profile map around the borehole, helping manage geological and well trajectory uncertainties while drilling.

This technology has proven highly effective in reducing the need for pilot wells. However, its full potential was limited until the recent implementation of more advanced technologies.

This paper presents our experiences with the latest developments in RMWD technology to support the landing, geosteering, and reservoir characterization of horizontal wells in the Campos Basin, offshore Brazil. It includes an overview of the main challenges faced for horizontal well placement optimization within turbiditic sands, a technical description of the technologies and workflows implemented, as well as examples of their application and results.

The latest developments in RMWD implemented in the Campos Basin include the high-definition (HD-RMWD) and the three-dimensional (3D-RMWD) system. The ultradeep electromagnetic measurements acquired are converted into a map of the resistivity profile around the borehole using inversion algorithms.

HD-RMWD offers multilayer detection through the incorporation of a higher-power transmitter and a one-dimensional (1D) deterministic parametric inversion engine. This results in a finer two-dimensional (2D) vertical map along the well trajectory when compared to the previous generation system. These enhancements significantly improve geosteering and reservoir characterization capabilities.

The new 3D-RMWD system expands the application of this technology to the most complex reservoir settings. A set of new electromagnetic measurements—the full 360° tensor—is acquired and transmitted to surface in real time using a new data compression algorithm. These measurements are then converted into 3D resistivity volumes using a cloud-based 2D transversal inversion technique.

The HD-RMWD system was implemented in 2021 to enhance proactive horizontal placement in the Campos Basin. For landing, it provides an actual detection range of approximately 20 m, facilitating precise casing placement in the desired target zone and identifying unexpected upper layers when present. Within the reservoir, the radial depth of detection achieved with a three-receiver configuration, in general, exceeded 30 m. This depth allows for mapping the top and base of sandstone reservoirs and identifying the presence of multiple thin beds, their dip angles, and fluid contacts when present.

The 3D-RMWD technology was recently introduced in the Campos Basin. Initial results demonstrate its significant potential for application in characterizing complex, non-1D geological environments and enabling geosteering not only vertically but also azimuthally to optimize hydrocarbon drainage.

The HD-RMWD system represents a significant advancement by providing a finer resistivity map around the borehole. On the other hand, the 3D-RMWD technology opens up entirely new possibilities, particularly for complex reservoir characterization, and offers the means for azimuthal geosteering, which is an avoided practice at this time. When used to its full potential, this 3D mapping technology is expected to enable horizontal well placement closer to fault planes or parallel to reservoir boundaries, optimizing hydrocarbon drainage. Additionally, these technologies have demonstrated their capabilities in reducing the need for pilot wells.

Enhancing Local Anisotropy Characterization With Ultradeep Azimuthal Resistivity Measurements
Hsu-Hsiang (Mark) Wu, Dagang Wu, Yijing Fan, Jin Ma, Clint Lozinsky, and Michael Bittar, Halliburton

Recent advancements in ultradeep azimuthal resistivity (UDAR) tools have successfully enabled resistivity boundary mapping in geosteering applications, primarily based on the inverted horizontal resistivity measurements of the formation electrical properties. This ignores formation anisotropy as another crucial parameter in formation evaluation. Due to limitations in the existing UDAR inversion, a global anisotropy assumption, where the same anisotropy ratio is attained for all layers, is frequently applied in the inverse process to reduce inversion unknowns. This assumption may suffice for inverted layers in close proximity to a wellbore or formations with low-resistivity anisotropy. However, it can lead to inaccurate anisotropy determination for adjacent layers situated at a certain distance from the wellbore.

In recent UDAR applications, the precise determination of individual layered anisotropy has become indispensable for geophysicists and petroleum engineers. Accurate knowledge of the resistivity anisotropy of each layer assists petrophysicists in evaluating the quality of sand-shale lamination, distinguishing between water zones and low-resistivity pay zones, and ultimately optimizing wellbore trajectories.

Existing inversion processes have been updated to determine the individual anisotropy of each layer in order to improve the characterization of local anisotropy in UDAR applications. Although the advanced inversion must handle a larger number of inversion unknowns, it offers a more realistic and accurate representation of geological formations. Furthermore, the updated inversion engine also provides valuable insights into inversion uncertainties, particularly for the determination of the vertical resistivity profile. This capability helps the identification of potential inversion artifacts, ultimately establishing a zone of confidence for engineers to make optimal geosteering decisions.

Figure 1 illustrates a two-dimensional (2D) anisotropic formation model along with corresponding 1D inversion results with and without the enhanced local anisotropy characterization. The inclination of the wellbore is 85°. Three-dimensional (3D) forward modeling was employed to generate the synthetic modeling responses that were used in the 1D inversion. As depicted in the figure, the inversion yields accurate inverted horizontal resistivity regardless of whether it is based on the global or local anisotropy model assumptions. In contrast, the local anisotropy inversion enables the identification of anisotropy in neighboring layers. Because of the resistivity orientation, it is important to note that the detection range of UDAR inversion is somehow diminished for vertical resistivity measurements as compared to horizontal resistivity measurements. In addition to the aforementioned synthetic example, more comprehensive sensitivity studies are discussed within the paper. Several field examples were evaluated by the enhanced inversion process and validated against other tool measurements and prior geological information.

In conclusion, the incorporation of local anisotropy inversion improves the characterization of both horizontal resistivity and anisotropy within formations, despite some limitations in detecting the range of vertical resistivity measurements along high-angle and horizontal well trajectories.

Fast Stochastic Inversion of UDAR Measurements Using Adaptive Multi-Grid Simulated Annealing Guided by Model Parameter Error Estimation

Nazanin Jahani, NORCE Norwegian Research Centre; Wardana Saputra and Carlos Torres-Verdín, The University of Texas at Austin

The growing demand for precise and efficient wellbore placement within heterogenous three-dimensional (3D) geological structures has propelled the adoption of 3D well geosteering. This approach necessitates the real-time inversion of borehole electromagnetic or ultradeep azimuthal resistivity (UDAR) measurements to estimate subsurface resistivities around and ahead of the well trajectory. However, in cases involving heterogeneous and/or anisotropic geological formations with multidimensional physical properties, the nonlinear nature of the inversion introduces challenges concerning efficiency, reliability, non-uniqueness, and uncertainty. Stochastic inversion techniques provide an effective strategy for exploring global minima and quantifying uncertainty, but standard approaches often suffer from computational inefficiencies. To estimate formation properties in real time, it is imperative to develop a computationally efficient stochastic inversion method for UDAR measurements. Adaptive simulated annealing has verified its robustness in tackling similarly challenging problems in the inversion of 3D seismic amplitude data. However, its application to UDAR inversion remains unexplored to date. The objective of this work is to develop a very fast one-dimensional (1D) stochastic inversion based on adaptive and multi-grid simulated annealing. Additionally, we aim to provide guidance for identifying regions that may benefit from two-dimensional (2D) or 3D inversion approaches. We assess the performance of this 1D inversion algorithm in estimating resistivity within 3D complex and heterogeneous formations, taking into account electrical anisotropy and the presence of thin layers.

The simulated annealing method is often employed to optimize temperature schedules dynamically, facilitating a rapid search for global minima in nonlinear estimation problems. In this work, we introduce three innovative enhancements to the conventional simulated annealing framework, aimed at achieving a faster and more stable inversion with improved property estimation reliability: (i) we developed a guided cooling schedule for annealing in which the annealing temperature is adjusted during the algorithm's execution based on feedback from model property errors; (ii) we introduced a stepwise multi-grid inversion approach, commencing with a larger inversion grid size. This involves a progressive reduction in the size of inversion pixels. Results obtained from each prior inversion with a larger grid are used as priors for subsequent inversions with smaller grid sizes. The decision to continue reducing the grid size is contingent upon observed improvements in data misfit and uncertainty; (iii) we implemented a segmentation strategy for measurements, restricting the inversion to specific subsets of measurements in computational domains where the measurements exhibit reliable spatial resolution and detectability. Figure 1 illustrates the stepwise multi-grid simulated annealing algorithm. We applied the algorithm to two distinct cases: (1) a 10-layer model sourced from the Norwegian Continental Shelf featuring true resistivity values spanning from 0.8 to 30 Ω·m. Measurements were generated from a 3D forward model, incorporating 2% Gaussian measurement noise and (2) a field case with two faults featuring an anisotropic background shale with thin layers and inputting actual field measurements.

Figure 2 describes the estimated resistivity values, relative uncertainty of the estimation, and data misfit for the first case. In this example, a total of 500 logging points were utilized, and the computations were distributed across eight Intel® Core™ i7-8665U CPUs, each running at 1.90 GHz. Following four annealing steps, the total elapsed time amounted to approximately 300 seconds. Our stepwise refinement method enabled us to achieve high-resolution formation property estimations at the distance of 20 ft (at locations with high electrical conductivity) to 60 ft (at locations with lower electrical conductivity) around the well trajectory while optimizing computational efficiency and ensuring stability. Comparative analysis with simple annealing techniques indicated that our method achieved significant computational efficiency gains, with convergence occurring at least 10 times faster. By enabling fast stochastic inversion and incorporating uncertainty quantification, our approach is effective for supporting informed decision making in complex 3D geological conditions.

High-Definition-Mapping UDAR Inversion Provides Accurate Geobody Geometries in a Complex 3D Reservoir
Karol Riofrio, Nigel Clegg, and Hsu-Hsiang (Mark) Wu, Halliburton; Joanna Mouatt and Fanny Dominique Marcy, Aker BP

Anisotropy and orthotropy at different measurement scales must be considered when mapping and modeling the subsurface, particularly complex three-dimensional (3D) reservoir architectures. Modern 3D seismic data provides imaging of large-scale features and 3D geobodies, allowing models to be built as part of the field development planning workflow. The indirect nature of 3D seismic imaging, coupled with coarse resolution and uncertainty of the measurements, generates further uncertainty in the well planning and construction processes. Real-time formation evaluation logs provide data about the geological changes along a wellbore during the drilling process, but due to their limited depth of detection, correlations against predrill models and other well logs are only valid for that specific well-log location, which also has positional and measurement uncertainty.

Data types that link different scales of measurement, such as ultradeep azimuthal resistivity (UDAR), are therefore valuable. UDAR systems have the capability to differentiate multiple layers or bed boundaries at the reservoir scale, supporting more detailed mapping of the geological features and architecture than 3D seismic. While many formations consist of simple layered units that can be characterized easily using one-dimensional (1D) models, some geological settings have additional complexity due to depositional settings, diagenetic changes, or transient production effects. Fractured injectite reservoirs are a perfect example of these types of complex 3D formations. In fractured injectite reservoirs, UDAR inversion tends to be highly affected by the 3D reservoir geometry since the geobodies rapidly change in dip, azimuth, shape, and thickness. 3D UDAR inversion methods were developed to accurately image injectite structures where 1D inversions previously had high uncertainty.

The new high-definition-mapping (HDM) 1D methods can now provide high-quality inversion results even in complex 3D reservoir settings. The uncertainties relating to the 1D solution in these settings must be well understood, and the interpretation is ideally accompanied by full 3D inversion, original 1D inversion, and azimuthal borehole imaging.

This paper presents the results of a trilateral development well in a North Sea injectite complex where UDAR was used to map and geosteer the horizontal reservoir sections. The structure of the injectite geobody in one of the wells was more complex than in the other two; however, by using an enhanced gradational resistivity model in the HDM inversion, the geometry of the geobodies closer to the wellbore was very well defined by 1D inversion. In combination with the square log model inversion, a greater depth of detection was achieved. When compared later to the full 3D inversion, it showed that 1D inversion solutions can, in the right environment, still provide robust imaging when mapping complex injectite geobody architectures.

Mapping Historical Waterflooding and Facilitating Production Strategy With the Use of New Reservoir Mapping-While-Drilling Systems: A Case Study From Offshore Norway
Yazil Abbas, Mauro Viandante, Emmanuel Ebuka Uzuegbu, Ahmed Zarroug El Sedeq, and Jean-Michel Denichou, SLB; Per Erik Wærum, Sven Severin Gundersen, Silje Agnethe Kommedal, Andrea Trollsås Liverød, and Bjørn Matre, Respol Norge AS

The time of easy drilling to produce oil from massive reservoirs is gone. Operators worldwide are now facing the challenges associated with mature brownfields with production water unevenly distributed.

Conventional development techniques based on static geological models are not enough to ensure commercial development using geometric drilling. The need for a multidimensional reservoir-mapping-while-drilling service is the key to unlocking the bypassed oil and achieving the production goals based on an updated understanding of reservoir fluids dynamics.

The YME field highlighted in this paper is in the southeastern part of the Norwegian sector of the North Sea and has an extensive production history dating back to 1996. After a pause of almost 20 years, the field is currently being redeveloped with the deployment of the latest reservoir-mapping-while-drilling ultradeep azimuthal resistivity (UDAR) technologies to aid horizontal well placement and enhance reservoir understanding. Apart from the structural uncertainty in the geological model, the main challenge in this development phase is to predict how the fluids have been redistributed during the last two decades of production, water injection, and associated fracking. In the absence of four-dimensional (4D) seismic data in this field, it's hard to ascertain new fluid contacts and the connection between any legacy wells with high water cuts, if any. To address these uncertainties, deployment of multidimensional UDAR reservoir mapping, which converts ultradeep electromagnetic measurements into a volumetric distribution of resistivity around the borehole, becomes imperative with two main objectives: (a) geosteer to maximize exposure of good quality reservoir and (b) map the reservoir heterogeneity and hence assist in a broader understanding of production effects from legacy wells.

With the current multidimensional UDAR technology, a comprehensive set of measurements known as the full 360° electromagnetic tensors are acquired and transmitted using a new data compression algorithm in real time. These measurements are then converted into three-dimensional (3D) resistivity volumes by linearly interpolating between a series of two-dimensional (2D) transverse inversion slices. While all the inversions are cloud-based, the reservoir mapping digital deliverables are available in real time, which can be utilized with industry-standard interpretation tools. The digital deliverables workflow provides 3D structural interpretation, geobodies, and 3D resistivity volumes in SEG-Y format, all facilitating seamless integration of real-time information with existing geological models and thereby improving reservoir understanding and helping to make educated geosteering decisions.

This paper presents the unique integration of multidimensional UDAR data with other LWD technologies, especially high-definition resistivity images that helped build a holistic understanding of a reservoir with a long history of production. Precise mapping of the water coning and fingered profile by UDAR can be easily linked to the legacy plug and abandonment wells using existing interpretation tools. This paper also highlights how digital deliverables from UDAR can help redefine the production strategy and revise production estimates by updating existing geological models based on UDAR data.

Revealing Subsurface Structures in Ultrahigh Definition With UDAR (Ultradeep Azimuthal Resistivity) Measurements – A Case Study From Brazil
Armando Vianna, Enrico Ferreira, and Sergey Martakov, Baker Hughes; Antonio Mainieri, Petrobras

This paper discusses a novel deep and ultradeep azimuthal resistivity (DAR and UDAR) inversion workflow utilizing an advanced parametric/hybrid inversion algorithm. It has been optimized to deliver ultrahigh-definition (UHD) results in real-time with an increased capability to resolve thin layers down to 1 m and improved depth of detection (DOD). We will demonstrate the results through a case history from a well located in an offshore field in Brazil, owned by a national oil company (NOC).

The new inversion workflow integrates DAR and UDAR measurements into discrete subsets according to the objective, whether that is either focusing on proactive reservoir navigation or geomapping. Then, the implementation of parameter domain scanning and forward modeling, supported by remote high-performance cluster computation, ensures results are delivered to support real-time decision making. The presence of two-dimensional (2D) influences on the inversion results are identified via data misfit and azimuthal signal differences from a range of frequencies. Where this difference is significant, a hybrid 2D inversion is applied leveraging artificial intelligence methods like artificial neural network (ANN) and a hybrid parametric inversion with the outputs' visualization in both 2D and three-dimensional (3D) space. In

3D, the data can be displayed in several visualizations from 2D transverse and 2D longitudinal inversion profiles along the well path, within a depth window, to a 3D volumetric depiction of the resistivity model. This is done by converting the 2D inversion results into a 3D voxel-based model to quickly determine volumetric data. The 3D resistivity voxel model can then be interrogated to identify subsurface geological features at varying scales.

This new approach was deployed in two horizontal oil producers and two water injectors to simultaneously conduct proactive reservoir navigation based on the high resolution of UHD inversions, while also supporting geomapping objectives by delineating remote boundaries, defining layer thickness and channel geometry, as well as apparent formation dip and petrophysics properties. These multiple objectives were achieved in real time, performing computations on a high-performance cluster. The results of UHD inversions are compared directly to high-resolution electrical resistivity images, and the resultant image interpretation illustrates good corroboration of boundary delineation and apparent formation dip of the two independent measurements. Therefore, the extrapolation of the geological interpretation from wellbore-centric to reservoir scale can be supported, providing a more field-focused analysis to deliver on fluid volumes, channel body geometry, and fault orientation at the reservoir scale. The enhancement of the real-time interpretation and strategic reservoir navigation is achieved through this new approach and delivers increased confidence in the geological interpretation of UDAR inversions and structural dips based on the deeper depths of detection delivered by ultrahigh-definition mapping. These developments support detailed analysis/interpretation of UDAR inversions in complex reservoirs with improved lateral continuity, early feature detection, and enhanced thin layer delineation possible.