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Technical Program Abstracts

NOTE: This is a tentative program and 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 in the Town Center South at The Woodlands Waterway Marriott Hotel & Convention Center. Photography and video/audio recording of any kind is strictly prohibited in all areas including technical sessions, workshops and exhibition hall.

CASE STUDIES

Application of Gamma Function in the Evaluation of Heavy Oil Reservoir In Peregrino Field Through NMR Well Logs

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The use of nuclear magnetic resonance (NMR) logs for petrophysical interpretation and evaluation in the oil and gas industry has increased in the last decades, especially in Brazil, where the use of this technology was increased by more than 400% from 2011 to 2018 (from 49 to 208 runs). This is mainly because the porosity estimation provided by this technology is independent of lithology. Additionally, the porosity can be associated with different pore sizes. It can also be divided to quantify the fraction of porosity for the clay bound water, bound fluid by capillary forces and movable fluid by applying cutoff times in the spectrum of T_2 distribution.

Nevertheless, the presence of heavy oil in the Peregrino reservoir, with oil viscosity varying from 150 to 350 cP, complicates NMR interpretation because the signal from the oil decays with a time constant that is comparable with that of capillary- or clay-bound water, affecting the determination of permeability and the fluid distribution.

This paper presents the results of applying the innovative Gamma Inversion to process the logging-while-drilling (LWD) NMR data acquired in a well from the Peregrino Field, Offshore Brazil. The Gamma Inversion process uses probabilistic functions, instead of exponential ones, to generate a T_2 spectrum that is more consistent from a mathematical and geological point of view.

This proposed processing combines these different probabilistic functions with the time decay of each component of the porous space. Up to 14 different probabilistic functions can be generated with time from 0.5 to 4000 ms generating a complete T_2 distribution. These probabilistic functions can separate signals from different fluids. A comparison between the products of the standard NMR processing using the Laplace inverse transform and the Gamma Inversion processing is shown.

The Gamma Inversion processing to generate the T_2 spectrum in the Peregrino Field allowed the interpretation of fluid types and better prediction of fluid productivity and saturation. It also supported the petrophysical interpretation by defining the optimal T_2 cutoff, and the true fluid distribution in order to get the different petrophysical properties of the formation, such as porosity distribution and permeability. These functions are significantly simple for facilitating petrophysical analysis.

Characterization and Production Influence of Geological Facies in the Eagle Ford

Jeremy Magness, Bhaskar Sarmah, Nicholas Garrison and Eli Bogle, Halliburton

The purpose of this study was to correlate subtle changes in reservoir quality to production. The groundwork was provided by unique lessons arising from core and log analysis, including machine learning, to identify target facies within the reservoir and stage-level production logs provided by permanent fiber-optic cable. Production results on a stage level produced by fiber optics provided insight into production drivers; these lessons were then applied to fracture and reservoir models.

The workflow began by categorizing unique facies within the Eagle Ford shale with the help of a self-organizing map model. Wireline-log variables, such as gamma ray, neutron porosity, bulk density, deep resistivity, and compressional slowness, were used to discern different facies within the Eagle Ford shale. These electrofacies demonstrated an excellent match with whole-core-derived facies, which took into account mineral volumetric compositional variation, carbonate grain-size variation, and kerogen content. Before completing the study well, a casedhole logging suite was run, and the facies were identified along the lateral. Permanent fiber-optic cable was installed on the backside of the casing to observe completions and production trends along the lateral. Experiments performed throughout the completions included varying rate and perforation design, use of chemical diversion and acid, and pump schedules. Fluid and proppant per lateral foot were held constant throughout the lateral. Calibrated fracture and reservoir models were then built around the observed completion effectiveness and initial production results of each stage.

Despite the changes in completion design, the only solid correlation in initial production is the facies identified along the lateral. The best producing facies were those with the highest porosity and organic content. Although a modeled fracture height exceeded 150 ft, the reservoir quality immediately adjacent to the wellbore is the largest determining factor in production. The completion design on the test well consisted of low-viscosity fluid and small-mesh-size proppant. Facies that may be as thin as a few vertical feet driving production on this well could be explained by proppant dunning and production being driven by the small channel of near-infinite conductivity that lies above the proppant dune. Undeniable trends in unconventional completions are more perforated clusters, pounds of proppant, and gallons of fluid per lateral foot. Reservoir understanding and quality lateral landing targets cannot be replaced by larger completions.

A multitude of studies and laboratory experiments have been conducted that validate the concepts of proppant dunning with low viscosity fluids in low-permeability reservoirs. This study expands upon these concepts and evaluates the effects of proppant dunning on production in a real-world scenario.

Estimation of Thomsen's Epsilon and Delta in a Single Core Using Ultrasonic Phase and Group Velocity Measurements

Gabriel Gallardo-Giozza, D. Nicolás Espinoza and Carlos Torres-Verdín, The University of Texas at Austin; and Elsa Maalouf, American University of Beirut

Elastic anisotropy plays an important role in unconventional and fractured reservoirs for seismic interpretation and for geomechanics applications, including the design of well completions and hydraulic fracturing. The quantification of elastic anisotropy is challenging because mechanical properties must be measured in cores for which there is limited availability in number and orientation. Furthermore, geomechanical measurements on cores are often destructive. New techniques are necessary to enhance the measurement of anisotropic elastic properties of cores under in-situ stresses and variable loading conditions.

Because of pervasive thin laminations, most unconventional rocks tend to behave as vertical transversely isotropic (VTI) materials. A common practice used to estimate the dynamic elastic properties of VTI rocks with triaxial frames requires three ultrasonic elastic-wave measurements on three independent cores acquired from the same interval in a well, with bedding angles of 0, 45 and 90°. The corresponding five independent Thomsen parameters (VP0, VS0, Epsilon, Delta and Gamma) are estimated from the compressional and shear arrivals at these three angles.

We developed a method to estimate VP0, Epsilon and Delta, using a single core with a bedding angle of 0 degrees inside the triaxial frame. This new method calculates the P-wave acoustic anisotropy of VTI cores using both phase and group velocity measurements. We measure phase velocities with conventional ultrasonic endcaps in the triaxial frame and add small-size transducers around the core sample to measure group velocities; this approach increases the angle coverage of the core, thereby enabling the calculation of Thomsen's Epsilon and Delta. The transducers work both as receivers and transmitters, generating a waveform dataset with tomographic coverage used to invert for the anisotropy parameters of the compressional-waves.

Estimating VP0, Epsilon and Delta is accomplished with least-squares inversion of phase and group velocities. Velocities for the inversion are obtained by picking the first arrival of the compressional-wave using only the small-sized transducers around the sample. Both the shear and compressional velocities measured using the ultrasonic endcaps are used to constrain the inversion; the shear velocity constrains the values of the estimated Epsilon and Delta, while the compressional velocity provides a measurement of the compressional velocity in the parallel-to-bedding direction.

Results from our study show that elastic anisotropic parameters can be measured at different stresses for a single core, with an error lower than 5% in weak elastic anisotropic rocks. Inverted parameters are consistent with parameters obtained using the conventional methods that requires three cores. Results can be biased if heterogeneities, fractures, or vugs are present in the core. Therefore, a preliminary analysis using X-ray tomography is recommended to define the location for the receivers and avoid the deleterious effect of rock discontinuities.

A tomographic coverage with small-size receivers in contact with a VTI core allows to quantify the dynamic elastic properties of rocks that are undergoing triaxial stress loading and fracturing inside a triaxial vessel. The elastic properties obtained using the proposed method show consistent results for weak elastic anisotropic samples when compared to measurements acquired from a single core.

Evaluation of Light Hydrocarbon Composition, Pore Size and Tortuosity in Organic-Rich Chalks Using NMR Core Analysis and Logging

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The laboratory NMR core analysis integrated with downhole NMR logging has proven to contribute significantly to formation evaluation. In this paper, we integrate laboratory NMR measurement with NMR logging to estimate the hydrocarbon composition in an organic-rich chalk prospect. We also use the NMR laboratory-measured restricted diffusion to estimate the mean pore size and tortuosity of the hydrocarbon-filled porosity.

Our core analysis consists of pressure saturation of the as-received reservoir core-plugs in an NMR overburden cell, followed by in-situ NMR T_1-T_2 and D-T_2 measurements. The saturating fluids in the core-plugs include water and light hydrocarbons, including: methane, ethane, propane, n-butane, n-pentane and n-decane.

The laboratory-measured T_2 distributions (projected from T_1-T_2 measurements) of the hydrocarbons in saturated cores are converted to T_{2app} (T_2 apparent) distributions by simulating the effects of diffusion in the magnetic-field gradients of the NMR logging tool. The core data indicate a large contrast in T_{2app} distributions between the different hydrocarbons due to different surface relaxivities and diffusivities. This contrast is used to estimate the downhole hydrocarbon composition by minimizing the least-squares error in the T_{2app} distributions between core and log data.

The laboratory-measured T_1/T_2 exhibits contrast between water and light hydrocarbons. The magnetic-field gradient of NMR logging tools amplifies the contrast and makes the downhole-measured T_1/T_{2app} favorable for fluid typing. We find that methane and natural gas liquids (NGLs) tend to yield higher T_1/T_{2app} compared to water and longer alkanes.

The laboratory-measured restricted diffusivity indicates that the saturating methane can be distinguished from liquid-state hydrocarbons by the higher diffusivity. In addition, the laboratory-measured restricted diffusivities of different light hydrocarbons are fitted to the Padé approximation to estimate the mean pore size, heterogeneity length-scale and tortuosity of the hydrocarbon-filled porosity.

We show how these new techniques could, in principle, be used to evaluate the tight-rock reservoirs.

Feasibility Study of Deriving Water Saturation From LWD NMR Transverse Relaxation Time in Two Siliciclastic Reservoirs In China

Zhou Xin, Schlumberger

To evaluate formation properties, a common methodology is to determine the reservoir porosity, permeability, water saturation through conventional measurements including gamma ray, resistivity, density and neutron. In order to obtain these properties, at least two or three logging tools need to be connected in the downhole assembly with a radioactive source. Several coefficients, such as *a* (tortuosity factor), *m* (cementation exponent), *n* (saturation exponent), and clay volume need to be determined through local experience or core laboratory results. Moreover, because resistivity is apt to be influenced by many factors, to obtain a reliable petrophysical result is costly and challenging.

A newly published method allows water saturation (S_w) to be derived from NMR transverse relaxation time (T_2) distribution. The method is considered an effective way to address the previously mentioned challenges because it is independent of resistivity. Especially in China, LWD nuclear magnetic resonance (NMR) tool was used in lots of 12.25-in. sections as an alternative tool replacing density-neutron measurements to eliminate the risk of running radioactive sources. To be more specific, the workflow to determine S_w builds on recent advancements of T_2 methods to extract maximum information from minimal NMR data acquisition, such as factor analysis, a statistical method to determine various T_2 cutoffs, and fluid substitution, a method to replace all hydrocarbons with water in the T_2 distribution. The workflow is summarized below:

1. Identify free-fluid T_2 cutoff from factor analysis of the T_2 distribution.
2. Perform T_2 fluid substitution to get T_2 log mean (T_2LM) of the distribution when pore space is filled with 100% water.
3. Establish T_2LM of 100% water and hydrocarbon, then, calculate Sw.

Using the proposed workflow, we conducted a case study on two wells in Bohai Bay. The target formation is a heterogeneous shaly sand formation that produces light oil. Both wells have core data in the main reservoir intervals. LWD triple combo, NMR and resistivity were acquired in both wells.

Overall, S_w derived from T_2 shows very good agreement with S_w calculated using the Archie equation in both wells. The feasibility of the proposed NMR method is well demonstrated in the study field. Although the reservoir is heterogeneous, NMR gives good results in most intervals. The differences between the two S_w values are attributed to factors, such as resolution difference, depth of investigation, shaly sand parameters, fluid characteristics, and have been closely studied.

With S_w computed from the T_2 distribution, NMR now delivers complete petrophysical answers of porosity, permeability and water saturation. S_w from T_2 can be used to corroborate resistivity-based interpretation or provide an independent reference when conventional interpretation is not conclusive.

Identification of Bitumen in Najmah Source Rock, Using Organic and Inorganic Analysis, a Case Study

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The Najmah Formation is a Middle Jurassic tight, fractured formation, distributed across all fields in Kuwait. The Najmah Formation in Kuwait is represented by a carbonate sequence with highly variable thickness with abundant kerogen and bituminous matter in the Lower Najmah Mudstone (source-rock unit).

The entire formation is interesting for its prospectively and it is cored in different locations in Kuwait in several wells, since its reservoirs are often vertically and laterally heterogeneous due to depositional variability and diagenetic alteration through space and time.

The bituminous intervals, often encountered drilling the Najmah, can induce damaging effects on oil recovery, such as reduction of total “productive” porosity, creation of permeability barriers, diminution of waterdrive efficiency, modification of fluid circulation and rock wettability. Drilling challenges associated with bitumen presence may also arise.

While fundamental questions still remain unclear and controversial, such as how bitumen behaves at in-situ conditions (high stress and high temperature), what shape is bitumen formation, and what mechanisms drive bitumen into the wellbore, the current consensus is to avoid bitumen intervals as much as possible.

This paper describes how geochemical data allowed for (a) the characterization of the organics present in the main reservoir, (b) the control of the presence of bitumen and the quantification of its amount in key cored well samples, and (c) the establishment of a methodology to tentatively extend the previous results to noncored wells.

Both organic and inorganic geochemical investigations were employed, namely total organic carbon (TOC), pyrolysis analysis, thermal desorption gas chromatography (TDGC), X-ray fluorescence (XRF), and X-ray diffraction (XRD).

Carbon is present in all organic components of the rock: kerogen, bitumen and liquid hydrocarbon.

Pyrolysis analysis can distinguish between free oil (the S1 peak) and heavy organic matter resulting from thermal cracking (the S2 peak), but it cannot differentiate the kerogen from the bitumen, both being included in the S2 peak.

However, kerogen is, by definition, insoluble in all organic solvents. This chemophysical property helped in the correct identification and isolation of this range of organic compounds: A long cycle treatment in a Soxhlet extractor using an azeotropic mixture of a high-polarity solvent; and a low-polarity one guaranteed an efficient extraction of all the soluble components, including the soluble part of bitumen. The comparative pyrolysis, i.e., the comparison of the original analysis with the second, post-treatment, analysis revealed the amount of the removed organic matter. An estimation of bitumen solubility, based on previous analysis on pure bitumen samples, allowed the assessment of total bitumen amount. An analogous procedure was set up for cuttings samples and its feasibility proved to depend on the type of drilling fluid used while drilling.

This study represents the first integrated characterization of a formation working both as source rock and reservoir rock with the inclusion of comparative pyrolysis in order to determine the presence of bitumen.

Imaging High-Resistivity Carbonate Reservoir Delineation and Well Placement—Application of a New HTHP Resistivity Imaging-While-Drilling Tool in China

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High-resolution wellbore imaging, deep and extended-range focused resistivity, and the ability to provide azimuthal quadrant resistivity measurements while sliding are key features of a new 175°C-rated laterolog resistivity imaging-while-drilling tool that has already generated high impact in China. This paper presents field application examples from different fields in China to show how the new technologies are solving field development challenges and generating significant cost savings for the operators.

The azimuthal laterolog resistivity imaging tool in 6.75-in. collar has been used to acquire logging-while-drilling (LWD) resistivity and wellbore-image logs in more than 10 wells in the Sulige Gas Field, Changqing Oilfield, and Jidong Oilfield, addressing formation evaluation needs in heterogeneous, low-porosity, or low-permeability and other complex reservoirs. Excellent agreement has been achieved between the LWD resistivity measurements from the new tool and traditional wireline resistivity logs, when available. High-resolution wellbore images from the tool have been used to delineate more accurately formation layers and to determine the reservoir thickness. Borehole breakouts from wellbore images are also used to aid wellbore stability and geomechanical analysis. In a high-angle well in Jidong Oilfield, wellbore images while drilling reveal how the wellbore enters and exits the dipping formation layers, demonstrating the ability to describe accurately the formation structures and to optimize the placement of well trajectories.

In Qinghai Oilfield, the fine wellbore images from the LWD tool are used to characterize the complex geology in the presence of extensive faults, fractures, and complex folds, providing the same types of information that are traditionally obtained only from wireline electrical images. The ability to characterize formation geology while drilling presents significant opportunity in operational time and cost savings in high-angle wells by eliminating wireline trips, which could take up to 100 hours to run.

In the Tarim Basin of West China, complex geological structure, high tectonic stresses, and overpressured and fractured reservoir formations in the field, coupled with downhole temperatures above 150°C present a huge challenge to drilling and logging programs. Wireline logs typically cannot be obtained due to the risk of wellbore instability. Understanding formation type and geological structure, and characterization of complex dolomite karst, such as caves, vugs and fractures, are important for well placement and field development. Wellbore images while drilling from the 4.75-in. collar tool have been used instead to characterize the reservoir types and identify unique characteristics in different formations. In addition, the tool's ability to measure very high resistivity in the range of thousands of Ω-m in conductive mud allows proper delineation of potential pay zones from anhydrate formation, meeting the logging requirement for the wells. The integration of deep resistivity, wellbore images, and azimuthal gamma-ray measurement into the same collar and HTHP rating makes this LWD tool a versatile sensor to include in any bottomhole assembly to aid accurate formation evaluation and well-placement applications.

LWD Resistivity Anomalies in Overburden Sections Provide Critical Information on Drilling Safety and Borehole Stability: Gulf of Mexico Case Studies

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Typically, only conventional logging-while-drilling (LWD) resistivity and gamma-ray logs are acquired in overburden sections of deepwater wells. Very important decisions impacting drilling safety and borehole stability must be made based on correct and timely interpretation of these logs.

Drilling-induced fractures, faults, and eccentricity effects in large holes drilled with oil-based mud are common reasons for anomalous responses of LWD resistivity tools in overburden sections. These anomalies are often associated with fluid losses and other drilling hazards, such as borehole assembly sticking. With the limited number of real-time (RT) measurements, even if the optimal minimal set of RT curves is selected, the interpretation of these anomalies is challenging. Drilling-induced fractures can be misinterpreted as eccentricity or even as a permeable zone with resistive invasion in water sands or with a hydrocarbon-bearing layer, which is especially important for proper casing and cementing decisions. Resistivity modelling is an irreplaceable tool that enables us to uniquely identify the cause of each anomaly.

Time-lapse measurements also help to recognize and identify the causes of anomalies as borehole conditions change with time. Fractures can become deeper with continued overbalance or healed with lost-circulation material or a reduction of equivalent circulating density. Washouts typically enlarge with time and after reaming.

We present several case studies from deepwater wells in the Gulf of Mexico illustrating typical LWD resistivity anomalies in overburden sections. The examples include fault identification and borehole events, such as fluid losses, borehole enlargement, and gas-bearing intervals. The challenges of interpreting each anomaly and the necessity of the appropriate LWD resistivity modeling kit are clearly demonstrated. Many of the examples illustrate the advantages of measuring after drilling (MAD pass) logs.

Turning a Negative into a Positive: Shale Annular Barrier Identification for Plug and Abandonment

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While shale formations can be problematic during the drilling of a well, those same shales have mobile characteristics that can make them extremely valuable as barriers during plug-and-abandonment (P&A) operations. Under certain circumstances, the mobility of shale formations can displace against the casing and create impermeable annular barriers. The impermeable nature of the displaced shale formation means that it acts as an acceptable annular barrier where the cement annular barrier is not of acceptable quality.

Particularly relevant to P&A operations, the ability to efficiently identify suitable shale annular barriers during logging can negate the need for any costly and time-consuming remedial cement work, yet ensure well integrity for P&A.

A comprehensive road map for identifying shale annular barriers using acoustic and ultrasonic logging tools is discussed. Using available openhole data, the expected shale-barrier impedance-log response was predicted, lending more confidence in the results. The simultaneous ultrasonic casing-inspection data are integrated into the shale-barrier assessment to measure the casing ovality, a feature of formation displacement compared to a cement annular barrier. A robust pass-or-fail criterion was established before logging operations.

Multi-Variable Threshold Processing (MVTP) was used to automatically compare the logged result to the established criteria for an acceptable formation barrier and allowed the operator to determine the way forward before the logging tools were even at surface.

Case studies are presented from multiple wells as part of a P&A campaign to highlight the success of shale-barrier identification using logging tools ostensibly designed for cement-evaluation logging. The integrity of the shale barriers was subsequently confirmed using pressure testing per the relevant regulations.

Uncertainty Analysis in Formation Evaluation: Rationale, Methods and Examples

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Upstream Uncertainty Analysis (UUA) frameworks are designed to support geologic and engineering decisions with significant business risks. While those frameworks ultimately focus on the 3D (static) and 4D (dynamic) characterization of the subsurface, their implementation start at the 1D well-scale with petrophysicists as key players.

This paper aims to highlight that petrophysical interpretations are not 'hard' data and that there is much to gained by estimating and communicating petrophysical uncertainties. Petrophysicists deal with incomplete and unknown information in all steps of the petrophysical analysis: well-log acquisition, calibration, processing, and interpretation. Each of these steps has uncertainties that can affect the final results. The key objectives for petrophysical analysis are to reduce the systematic errors, and to perform a consistent analysis between wells. Formation evaluation (FE) uncertainty analysis (UA) attempts to include different sources of uncertainty (log measurements, submodel approximations, heterogeneity, and natural variability of the rocks), and efficiently communicate those uncertainties to team members and management.

This paper explains how uncertainties in FE can be practically quantified through various error-propagation approaches, and proposes simple standards for communicating FEUA outputs. Direct benefits and limitations of FEUA are illustrated with applications ranging from (1) assessment of farm-in opportunities, (2) challenging multiwell petrophysical model development and implementation in a tight carbonate field for geomodel building, and (3) petrophysical support for rock physics modeling linking the physical properties measured at the well with petrophysical, elastic and seismic properties.

General and systematic use of FEUA helps petrophysicists to take full ownership of well data and interpretations, including uncertainty, and conform to standards defined by UUA framework, i.e., software tools and workflows for systematic integration of data and interpretation to quantify magnitude and probable distribution of asset value. The most direct and obvious benefits of FEUA include a check that (1) petrophysical results are within expected errors, (2) alternative scenarios/interpretations have been considered early in the evaluation process, and (3) inputs to sensitivity studies and geostatistics for static and dynamic subsurface descriptions are produced in a timely and consistent manner.

What if There was a Better Formation-Testing Probe? A Case Study on Optimizing Flow Geometry

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On a recent logging job, a formation tester was used to acquire water samples across a zone drilled with water-based mud (WBM). During operation, the formation-testing tool encountered severe plugging and malfunctioned. The end result was that a sampling job that was planned to take two hours ended up taking 10 hours and another run (more rig time). Eventually, low contamination samples were successfully collected but the logging job was suboptimal.

This paper examines several what-if scenarios on how long sampling should have lasted if the tool had worked under optimal conditions and with more adequate probe configurations. Selecting the best tool for a specific type of reservoir properties is a crucial part of a fluid-sampling job. Moreover, uncertainty in sample quality increases when the fluid phases are miscible, e.g., water-saturated formation invaded with WBM filtrate. Our objective is to quantify the filtrate-cleanup efficiency for various formation-testing tools to optimize fluid-cleanup times and sampling quality, under both wireline and logging-while-drilling conditions. The study is carried out using a reliable compositional simulation algorithm for the case of a water-saturated reservoir invaded with blue-dye tracer included in WBM filtrate.

History matching of the field measurements allows calibrating the model for further modification to account for a wide variety of fluid and reservoir conditions. Complex tracer dynamics of a blue-dye WBM invading a water-saturated formation and fluid pumpout are accurately and expediently modeled using a flexible numerical algorithm to account for different probe types and tool configurations. Under normal operating conditions, the chosen formation tester would have taken one hour to clean the filtrate contamination to a target value of 5%. On the other hand, the best choice of tool was found to be the focused elliptical probe, for which fluid cleanup would have taken less than 40 minutes. Additionally, a different tool configuration with a combination of multiple probe geometries spaced radially around the tool would provide even faster cleanup times, of only 30 minutes or less, thereby saving precious rig time.

Our study ranks 13 commercial probe designs as part of what-if scenarios under equivalent reservoir conditions. These examples highlight the importance of probe geometry and configuration together with reliable and expedient numerical modeling during the prejob phase to reduce cleanup time in anticipation of complex reservoir conditions. Furthermore, numerical simulations compare the fluid-cleanup efficiency for various commercial formation-testing probes together with innovative probe designs that could potentially lead to a new tool or probe development. Perfecting both the probe geometry and the fluid-pumping schedule is the most important output of our study.

COMPLETION PETROPHYSICS

A New Petrophysical Correlation for the Permeability of Carbonate Rocks

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Investigation of the permeability of carbonate rocks is essential and challenging due to the heterogeneity of carbonates at all scales. At the microscale, pore geometry, pore-size distribution, and pore connectivity are important factors controlling permeability. This study focuses on the influence of pore-size distribution and pore structure on permeability to better understand the fluid flow in carbonate rocks.

In this paper, we use microcomputed tomography (micro-CT) to capture the microscopic heterogeneity in the pore structure. Firstly, we collected seven 1×6 in. carbonate rock samples including Indiana Limestone, Desert Rose, and Travertine with various porosities and permeabilities. The porosity was measured gravimetrically, and permeability was measured with core-plug flooding experiments. Cubic centimeter-size core samples were scanned with enhanced micro-CT imaging with the resolution of 6 to 8 mm/voxel, then scanned 2D images were processed with image processing software to distinguish the pore system from the matrix. The pore-size distribution for each rock sample was determined by fitting a statistical function based on the binarized images. We defined a concept of equivalent pore radius to characterize the pore system, which effectively filters out the noncontributing small pores and preserves the pores actually contributing to fluid flow. The relationship between the equivalent pore radius of each rock and permeability was investigated. Based on the 2D image stack, we also constructed the 3D pore network to observe the pore structure, quantify connectivity and specific surface ratio to study their influence on permeability.

We found that laboratory-measured permeability from core plugs was strongly correlated to the equivalent pore radius calculated from micro-CT scanned images among the investigated carbonate rock samples. The semilogarithmic correlation between permeability and effective pore radius fit the measured permeability data very well over a permeability range of more than two orders of magnitude. The findings of pore-scale pore structure and pore -distribution in this study are helpful for carbonate rock analysis, and the proposed new correlation between equivalent pore radius and permeability is practical for permeability estimation for a wide range of carbonate rocks.

A Petromechanical Approach to Completions Optimization in the Bakken

Carrie Glaser, Fracture ID, Kyle Trainor, NP Energy Services and Joel Mazza, Fracture ID

In unconventional reservoirs such as the Bakken petroleum system in North Dakota, completions operations account for over half of well costs. The investment in completions reflects the importance of an effective stimulation in driving well performance. Optimization of stage length, cluster efficiency, and fluid and proppant volumes to maximize production while reducing costs can have a significant impact on an operator's return on investment. The ability to account for variations in lithologic attributes between stages and wells may help to simplify the complex process of completions optimization.

Petrophysical analyses in horizontal wellbores can be designed with the requirements of the completions operation in mind, focusing on lateral heterogeneity of mechanical and reservoir properties. By comparing these analyses directly to key production and stimulation metrics between stages and between wells, compelling improvements in ROI and future cashflow can be demonstrated.

Minimizing stress variability within a given stage improves cluster efficiency and proppant distribution. Evaluating the role of fractures during stimulation and post-treatment production helps identify how to distribute capital spending in the lateral. Identifying changes in reservoir quality that correlate to production helps identify segments of the lateral that may require different levels of stimulation intensity. Petrophysical interpretation in horizontal wellbores helps to maximize the return on investment for each well.

This paper describes a petrophysical workflow and completion optimization through a Bakken case study. The results incorporate water- and oil-specific chemical tracers and in-situ rock mechanics data from drill-bit accelerations. These form the foundation of a petromechanical interpretation of the lateral variability in mechanical and reservoir quality. The resulting completions optimization strategies are shown to significantly improve ROI in the Bakken.

Integrated Approach to Evaluate Rock Brittleness and Fracability for Hydraulic-Fracturing Optimization in Shale Gas

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To economically develop unconventional reservoirs, it is essential to understand the variation in reservoir properties and rock physics throughout the entire field to help identify sweet-spot areas and guide both completion and hydraulic-fracturing designs. The brittle shale is more likely to be naturally fractured and more likely to respond well to hydraulic fracturing. Ductile shale, on contrary, is more plastic, absorbs energy, and is not considered a good producer. In such cases, formation tends to heal any natural or induced fractures. Thus, formation sections with high brittleness are considered a good candidate for hydraulic fracturing. However, many authors argue that this viewpoint is not reasonable because rock brittleness is not an indicator of rock strength and the current brittleness indices are based on elastic modulus or mineralogy. Brittle rock just has shorter plastic deformation, and it is not certain that it is easier to fracture brittle rock than ductile rock since brittle formation may have greater strength than ductile formation.

The paper presents a fracability model that integrates rock elastic properties, fracture toughness and confining pressure. Logging and laboratory core testing data were collected from Khataba shale wells in Egypt. Laboratory testing was conducted to understand the complex rock mineralogical composition. Geomechanical rock properties derived from analysis of full-wave sonic logs and core samples were combined to develop sophisticated models to verify the principle of brittleness and fracturability indices and to demonstrate the process of screening hydraulic-fracturing candidates. Tensile and compressive strength tests are conducted to better understand the rock strength. Once the data were available, different methods were used to calculate brittleness and fracability indices considering effect of mineralogical composition and elastic moduli.

A rock fracability term is introduced to correct the shortcoming of rock brittleness. Fracability is defined as the rock failure under the ultimate rock strength in either brittle or ductile formation. The higher the fracability of the formation, the smaller formation strength. Therefore, the good hydraulic-fracture candidate is the formation that not only has high brittleness but also high fracability, thus, less energy is required to induce fracture. Higher fracability index represents the best candidate intervals for hydraulic fracturing because lower energy is required for the induced fracture to propagate. The rock exhibits fracable and is easier to respond to hydraulic fracturing and tensile failure at condition of high Young's modulus, low Poisson's ratio, low bulk modulus and low fracture toughness conditions.

This study improves the understanding of brittleness and fracability indices and reservoir mechanical properties. In addition, it provides valuable insight into optimization of completion and hydraulic-fracturing designs and helps in identifying desirable hydraulic-fracturing intervals and identifying sweet spots within each prospect reservoir.

DEEPWATER RESERVOIR ANALYSIS

A Neutron Induced-Gamma-Ray-Spectroscopy Logging Method for Determining Formation Water Salinity

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Formation water salinity is a crucial parameter for reservoir evaluation. Traditionally, sigma logging, resistivity logging and core-sampling methods are used for the water-salinity determination. Due to the high capture cross section of the elements (such as boron and gadolinium) existing in the borehole or formation, the salinity results from the sigma logging may be unreliable. For the resistivity logging, the salinity results always are affected by the conductive minerals, and there are some limitations when it is working in the cased hole. Generally, the salinity results derived from the core-sampling method are the most reliable for geological analysis. However, the sampling method is time consuming and easily affected by the formation heterogeneity. As a result, accurate water-salinity measurements always require a joint interpretation of sampling and logging data.

The neutron slowing down or capture ability is depending on the formation cross section. Usually, the lithology, porosity and borehole-fluid condition will affect the salinity determination when using a neutron logging method. Here, we developed a neutron induced-gamma-ray-spectroscopy logging method for determining formation water salinity. The measurement system Controllable Neutron Element Tool (CNET) consists of a D-T generator, one gamma detector ($LaBr_3$), and two thermal-neutron detectors (He-3). The $LaBr_3$ detector is covered with a thin boron-containing material for absorbing the thermal neutrons. The timing sequence of the D-T generator is designed according to the energy and time windows for the gamma-ray and thermal-neutron acquisition. Therefore, the energy spectrums of gamma rays in the inelastic and capture stage can be recorded, as well as the time spectrums in the attenuation stage.

As well known, chlorine content is a key index for formation water salinity. The characteristic gamma rays of the chlorine and other formation elements overlap on the capture-gamma energy spectrum. By using the weighted-least-squares method, the capture spectrum with a specific energy range can be resolved to derive the gamma counts related to chlorine. Then, formation porosity can be given by the thermal-neutron count ratio. Combining the gamma counts related to chlorine with thermal-neutron counts and porosity, the water salinity is derived. Meanwhile, the formation sigma information from the gamma-ray time spectrum can be used as a reference parameter for the water-salinity results. In addition, corrections for borehole water salinity and borehole size need to be considered.

This paper introduces a new method and its performance in different formation and borehole conditions. The effects of formation lithology and elements with high capture-cross-section on the salinity measurement are eliminated. Borehole and formation sigma responses for water salinity can be a good comparison for more believable results. The logging method is applied in two wells with different lithology and borehole fluids. Formation water salinity of different depths is calculated and comparing with sampling information to validate the effectiveness of this logging method.

Integrated Reservoir Characterization in Deepwater Gulf of Mexico Using Nuclear Magnetic Resonance (NMR) Factor Analysis and Fluid Substitution

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A novel integrated workflow using nuclear magnetic resonance (NMR) data is developed to evaluate sand reservoirs in deepwater Gulf of Mexico. Accurate characterization of the reservoir properties is the key to predict the formation producibility. Traditional interpretation methods based on triple-combo logs (density, neutron, resistivity and gamma ray) have been widely used to characterize clastic formations to provide cost-effective answers of lithology, porosity, saturation and permeability. Nevertheless, zones with fine-grained rock texture or clay-rich thin beds represent

low resistivity, causing net-to-gross estimation often pessimistic. Grain-size variation and clay distribution also affect the vertical permeability and connectivity. Moreover, the traditional methods cannot provide other important quantities of interest, such as hydrocarbon properties, sand facies and reservoir quality indicators.

The new approach incorporates modern techniques of NMR factor analysis and fluid substitution to fully characterize the formations by: (1) identifying fluid types, evaluating clay distribution and hydrocarbon properties, quantifying porosity, saturation and permeability; (2) analyzing fluid facies from NMR factor analysis for rock typing to separate shale, clean sand and laminated sand intervals; (3) computing grain size distribution from a simulated 100% water-filled formation using NMR fluid substitution; and (4) evaluating reservoir quality and producibility based on the reservoir properties estimated from steps (1) to (3).

In this paper, we demonstrate the successful application of the proposed workflow to wells in deepwater Gulf of Mexico. Case studies are presented using NMR data integrated with triaxial resistivity, borehole image, core analysis and formation-testing data. The results provide more accurate reservoir properties for better reservoir quality characterization. Furthermore, the new workflow can help reveal additional pay in the low-resistivity laminated-sand zones.

Using a Neural Network to Estimate Net Sand From Borehole Images in Laminated Deepwater Reservoirs

Bo Gong, Dustin Keele and Emmanuel Toumelin, Chevron

Deepwater reservoirs often consist of highly laminated sand-shale sequences, where the formation layers are too thin to be resolved by conventional logging tools. To better estimate net sand and hydrocarbon volume in place, one usually needs to rely on high-resolution borehole image logs, which can detect extremely fine layers with thickness of several millimeters.

Traditionally, explicit sand counting in thin beds has been done by applying a user-specified cutoff on a 1D high-resolution resistivity curve extracted from electrical borehole images. The workflow generally requires meticulous image QC, multiple preprocessing steps and log calibration, and the results are often highly sensitive to the cutoff selection, especially in high-salinity environments, where resistivity in pay sand can be very close to that in shale. In oil-based mud (OBM), accuracy of the cutoff method is further limited by the presence of nonconductive mudcakes and possible tool artifacts.

This paper presents a new method that estimates sand fractions directly from OBM borehole images without extracting an image resistivity curve. The processing is based on an artificial neural network, which takes a 2D borehole image array as input, and predicts sand fractions by applying a nonlinear transformation to all the elements, i.e., electrical measurements from all button electrodes. A cumulative sand count can be computed after processing the borehole image logs foot-by-foot along an entire well. The neural network is trained on a large dataset with example images of various degrees of laminations, labeled with sand fractions identified from core photos. Upon testing, a good match has been observed between the prediction and the target output. The results have also shown advantages against another sand counting method based on texture analysis.

The described method offers new opportunities of quantifying thin sands in the absence of cores, which can be used to improve petrophysical interpretation in laminated reservoirs. With appropriate tuning, a pretrained network model could also be generalized to applications in new wells or even new fields with similar depositional environments.

FORMATION EVALUATION BEHIND CASING

A Second Life for a Giant: Casedhole Pulsed-Neutron Logging in Complex Completions and Challenging Fluid Scenarios

Gabriele Duci, Roberto Zarauti, Alessandro Fasto, Marco Pirrone and Giuseppe Galli, Eni S.p.A.

Years and years of huge hydrocarbon exploitation from a giant field results in a not efficient production optimization strategy due to the high uncertainty in current reservoir fluid distribution. This scenario can be even more challenging in the case of old and complex well completions and areal field compartmentalization.

This paper discusses design, interpretation workflow and results of a massive casedhole pulsed-neutron campaign performed in such conditions. The outcomes have driven several targeted well interventions for additional hydrocarbon production.

The presented case study deals with extensive pulsed-neutron log use in a reservoir characterized by more than 3,000 meters of gas, oil and water-bearing terrigenous sequence. An integrated capture (sigma mode) and inelastic (carbon/oxygen mode) approach overcomes the criticality of a strong change in formation water salinity (one order of magnitude from hundreds to tens parts per thousand). Small tubing in large casing environments, long perforated sections, and different fluids in completion make the interpretation even more complicated. The available openhole formation evaluation represents the input for the pulsed-neutron modeling while a standalone casedhole formation evaluation has been deployed in the oldest wells characterized by a limited openhole log dataset. Actual water saturation and hydrocarbon type from the described approach have been used for water shutoff interventions and new perforations in front of bypassed oil-bearing levels avoiding undesired gas production.

The aforementioned production optimization activities for all the analyzed and treated wells resulted in an overall increase in oil rate of about 350% and a water-cut reduction of about 40% with respect to the previous performance.

Caliper-Behind-Casing—Using Nuclear Logging Tools to Replicate Openhole Caliper Measurements in Cased Holes

Ben Clarricoates and Manus Lang, Weatherford

There are approximately 10,000 coalbed methane (known locally as coal-seam gas or CSG) wells in the Surat and Bowen Basins of Australia. It is estimated that a third of these wells experience significant levels of solids production. This is a notable problem for

CSG operators and requires some form of corrective action. Believed to be caused by deterioration of interburden clays, a measurement of how the wellbore outside of the casing has changed since openhole logging, such as caliper, would enable a more intelligent approach to any remedial workover. Research into such a 'caliper-behind-casing' measurement is relatively unexplored. This paper introduces and investigates the use of wireline nuclear logging tools for this unique problem.

Using nuclear simulation software, the relationship between borehole diameter and detector count rate was characterized for standard completions found in Queensland CSG wells. A range of typical formation properties was then simulated to develop a correction algorithm, which was able to compensate for the variations in formations found in these environments, the input to be provided by precasing openhole logging. These variations are normally the variables of interest in conventional logging, but for a caliper-behind-casing measurement, they represent sources of error. Testing of this measurement was done with controlled laboratory logging of well characterized blocks, in addition to field-based testing on identified problem wells scheduled for remedial work.

In this paper, we show how nuclear logging tools can provide a caliper-behind-casing measurement of up to 18 inches when logged through casing. Therefore, estimations of hole volume are calculated more accurately by taking into account the unknown rugosity. Identification of potentially problematic features, such as bridges, is made possible. Excellent verification of the modeling provided by the laboratory-based benchmarking is seen. Finally, example logs from case studies show measurement repeatability and improve understanding of the fundamental problem of formation deterioration in the CSG wells that were included in this study.

The application of this new measurement provides significant potential for improvements in operational efficiency in Queensland CSG.

Impact of Cement Quality on Carbon/Oxygen and Elemental Analysis From Casedhole Pulsed-Neutron Logging and Potential Improvement Using Azimuthal Cement-Bond Logs

Haijing Wang, Michael Sullivan, Yegor Se, David Barnes, Michael Wilson and Michael Lazorek, Chevron

New-generation pulsed-neutron logging (PNL) tools can now measure thermal-neutron capture cross section (sigma), carbon-oxygen ratio (C/O), and mineral composition of the formation through casing and cement. Environmental corrections, including casing and cement corrections, are required for proper interpretation. Such corrections are currently done through empirical manual shifts, without considering the actual cement-bond quality or possible voids and channels in the cement, and the proximity of those voids to the position of the logging tool. Information from azimuthal cement-bond logs can be potentially used as quantitative inputs for C/O saturation calculation and mineral composition analysis, such that voids in the cement are accounted for, and with assumptions on what fluids might be filling the cement voids.

Here, we use the Monte Carlo nuclear modeling technique to quantitatively assess the impact of cement quality on C/O and elemental analysis. A generic two-detector PNL tool model is used in the simulation, along with realistic formation and borehole properties to reflect a horizontal cased-well. Several scenarios are simulated with a variation of casing centralization, the location of a channel in cement, and the type of fluid filling the channel. Neutron-induced gamma rays are tagged by the location and element of their generation and counted at two PNL detectors as a convenient measure of C/O and calcium yield. We demonstrate that a channel filled with oil-based mud could have considerable effect on C/O saturation calculation, whereas a channel filled with water-based mud has negligible effect. Calcium in cement can have considerable contribution to the total calcium signal. Any channel or void in cement will affect the calcium correction for elemental analysis. These significant impacts of the cased hole environment can be more efficiently accounted for by integrating azimuthal cement-bond logs as a quantitative input to the C/O and elemental analysis of PNL, but advances in workflows and environmental corrections will be required to make this practical.

Lessons Learned From Casedhole Formation Evaluation Along Unconventional Horizontal Wells

Michael Sullivan, Haijing Wang, Alexei Bolshakov, Lisa Song, Michael Lazorek, Vahid Tohidi and Yegor Se, Chevron

Revolutionary development of unconventional resources for the last two decades has been largely enabled by horizontal drilling and multistage hydraulic fracturing. With geosteering, horizontal wells as long as 20,000 feet can now be placed within a stratigraphic target window as thin as 6 feet, maximizing the wellbore exposure to the reservoir. The philosophy of engineered completions is to place perforation clusters in like rock so that all perforation clusters fracture simultaneously, and not have one cluster take all the fractures. Petrophysical data are needed as a foundation for engineered completion efforts to maximize stimulation effectiveness. Driven by constant effort to reduce rig time, offline casedhole logging has been tested as an alternative to openhole wireline logging along horizontal wells. Acquisition of petrophysical data in cased hole is possible, but there are additional complications that do not exist when logging in open hole, which if not properly accounted for, can result in the logging objectives not being met. The intent of this paper is to communicate those complications and potential pitfalls as well as recommendations to help ensure success.

Here, we show a case study of casedhole formation evaluation along horizontal wells in unconventional reservoirs, and share lessons learned from an operator's perspective. The casedhole logging suite includes spectral gamma ray, new-generation pulsed-neutron, and dipole sonic logs, with objectives to evaluate porosity, mineralogy, total organic carbon, Poisson's ratio, and Young's modulus along lateral wells. We emphasize the impact of completion design and hardware on casedhole measurement, which would require additional casing and cement corrections for pulsed-neutron spectroscopy logs and impose special requirement on sonic tool properties and functionalities. For instance, the iron and calcium elemental measurements from pulsed-neutron spectroscopy logs need to be corrected for completion hardware, such as casing clamps and centralizers, and variable cement-bond quality along the circumference and lateral direction, respectively, before proper interpretation. A sonic tool used in horizontals needs to be stiffer and shorter than a regular sonic tool and should be able to fire and acquire both monopole (for compressional slowness) and four-component crossed-dipole (for fast- and slow-shear slowness) modes. Casedhole dipole sonic logs can be dominated by the casing signal especially if microannulus is present. The significant impact of the casedhole environment can be more efficiently accounted for by integrating azimuthal cement-bond data as a quantitative input to the analysis of the nuclear and sonic logs, but advances in workflows and environmental corrections will be required to make this practical.

FORMATION EVALUATION OF CONVENTIONAL RESERVOIRS

A Logging Case Study of a Gulf of Mexico Subsalt Deep Miocene Well: Highlighting New Technology and Applications in a Challenging Environment

Brian LeCompte, Murphy Oil; Charlie Jackson, Rohin Naveena-Chandran, Gary Kainer and Baris Guner, Halliburton; Nicola Capuzzo, Task Fronterra Geosciences; Ron Balliet and Glenn Wilson, Halliburton

An exploration well, drilled to over 30,000 feet to evaluate an ultradeepwater Gulf of Mexico prospect, was logged to evaluate stratigraphic and structural features identified in the prospect's initial exploration well. The 2018 wireline logging campaign included a high-fidelity borehole imager, multicomponent induction, multifrequency magnetic resonance, rotary coring, and formation sampling for pressure and fluids. The formation sampling encountered extreme high-pressure overbalance, which required over 10,000-psi drawdown to obtain a fluid sample in one zone, and made all coring and sampling challenging.

This paper discusses the process of job planning, data acquisition, processing, and analysis of the multisensor petrophysical data, together with detailed borehole image analysis, to differentiate between the structural and stratigraphic features within the reservoir units. The resistivity image resolved uncertainties with the previous sedimentological interpretation. Logging from the previous exploration well in the field only acquired dips from triaxial resistivity. Anomalies and dip reversals were interpreted as faults, when in fact, the resistivity image log in the second well determined them to be slumps. The high-fidelity resistivity image was also used for determining the sand distribution in the reservoir, which is critical for characterization of subsalt, deep Miocene reservoirs in the Gulf of Mexico.

A New Apparatus for Coupled Low-Field NMR and Ultrasonic Measurements in Rocks at Reservoir Conditions

Paul Connolly, University of Western Australia; Joël Sarout and Jérémie Dautriat, CSIRO; Eric F. May and Michael L. Johns, University of Western Australia

Models that describe the effect of pore fluids on elastic-wave propagation in rocks are the basis for quantitative reservoir analysis. Laboratory ultrasonic measurements conducted on rock cores are often used to test the applicability of the various models and adapt them as required. Current saturation-wave velocity models usually require some description of fluid saturation and/or distribution, pore-aspect ratio, wettability and fluid viscosity. These are often measured indirectly at different experimental conditions to the reservoir or simply assumed. Hydrogen (^{1}H) nuclear magnetic resonance (NMR) is a technique that can be used to quantitatively describe some of these important parameters. Here we report the design and performance of a novel NMR-compatible core-holder system allowing for the measurement of both ultrasonic P-wave velocities and NMR relaxation parameters in rock cores at reservoir pressure and at variable fluid saturation conditions. Successful validation against a conventional benchtop ultrasonic measurement system was performed using a dry Berea sandstone core, while sequential NMR and ultrasonic measurements were performed on a Bentheimer sandstone core at reservoir pressures and as a function of variable brine saturation (coreflooding conditions).

To the authors' knowledge, this new apparatus represents the first documented example of coupled NMR and ultrasonic measurements conducted at the same experimental conditions on the same rock specimen, and allows for a new approach to study pore-scale saturation effects on elastic-wave propagation in rocks.

A New Workflow for Joint Interpretation of Electrical Resistivity and NMR Measurements to Simultaneously Estimate Wettability and Water Saturation

Chelsea Newgord, Artur Posenato Garcia and Zoya Heidari, The University of Texas at Austin

Wettability of rocks can be assessed from interpretation of borehole geophysical measurements, such as electrical resistivity and nuclear magnetic resonance (NMR). The existing wettability models often require additional inputs (e.g., water saturation, porosity, pore-geometry-related parameters) that are difficult to obtain independent of resistivity and/or NMR measurements. Consequently, a multiphysics workflow that integrates resistivity and NMR measurements can reduce the number of input parameters and nonuniqueness of the results, resulting in a more accurate and robust wettability assessment. The objectives of this paper are (1) to introduce a new method for joint interpretation of resistivity and NMR measurements for simultaneous assessment of wettability and water saturation, and (2) to verify the reliability of the joint interpretation workflow in the core-scale domain using experimental measurements.

The new workflow for estimating wettability and water saturation combines our newly developed nonlinear resistivity- and NMR-based rock physics models. The resistivity-based wettability model requires as inputs the resistivity of the rock-fluid system and brine, porosity, and pore-geometry-related parameters. The NMR-based wettability model requires the transverse (T_2) responses of the rock-fluid system, of the saturating fluids, and of water-wet water-saturated and oil-wet oil-saturated rocks. To verify the reliability of

the new workflow, we perform resistivity and NMR measurements on core samples from different rock types, covering a wide range of wettability and water-saturation levels. These measurements are inputs to the aforementioned nonlinear models, which are simultaneously solved to estimate wettability and water saturation for each core sample. We verify the reliability of the wettability estimates using the Amott Index and contact-angle measurements and the water-saturation estimates using the gravimetrically measured water saturation.

We successfully verified the reliability of the new method for wettability and water-saturation assessment in limestone and dolomite core samples. For the wettability ranging from oil-wet to water-wet, we observed an average relative error of 30% between the experimentally measured Amott Index and the estimated wettability using the new method. The estimated wettability values were also consistent with the contact-angle measurements. In addition to wettability assessment, the new method enables enhanced assessment of water saturation in mixed-wet rocks. For water-saturation levels ranging from irreducible water saturation to residual oil saturation, we observed an average relative error of approximately 15% between the gravimetrically assessed and the estimated water saturation using the new method.

It is challenging to estimate water saturation in rocks with multimodel pore-size distribution uniquely and reliably from the interpretation of NMR or resistivity measurements, separately. The introduced integrated workflow improved the accuracy of water saturation estimates in rocks with complex pore structure. This new multiphysics approach for simultaneous assessment of wettability and water saturation can potentially be adopted for in-situ reservoir characterization using borehole geophysical measurements. This new workflow relies only on physically-meaningful and measurable parameters which minimizes calibration efforts. Furthermore, the introduced multiphysics workflow eliminates the nonuniqueness associated with wettability and water-saturation estimates obtained from independent interpretation of NMR and resistivity measurements.

A Rapid Noninvasive Evaluation Method for Reservoir Fluid Samples

Ansgar Cartellieri, Erik Lehne and Maryam M. Alohaly, BHGE

The accurate prediction of crude-oil properties is essential for a comprehensive reservoir modelling and fluid characterization. Therefore, various analytical systems and measurement techniques are applied. The reservoir-fluid composition and physical properties are determined in certified laboratories on live oil and gas samples. The required samples are provided by wireline or while drilling-fluid sampling services or determined during production tests. The analytical data are then delivered to the production and field developing companies in turnaround times of several weeks to months.

For early decision making during the field development this is unsatisfactory. Obtaining the volumetric and phase behavior of the hydrocarbons already while drilling or soon after POOH provides important information on reservoir characteristics, such as compartmentalization, and local compositional variability of oil and gas enables an efficient field development. In addition, the provided data are essential for the reservoir and production management to mitigate operational risks, and to maximize production. Optical spectroscopy is the most common nondestructive fluid evaluation technique for sampling services. Due to limitations in current measurement systems and missing or inaccurate correlations to fluid laboratory data the prediction of the fluid pressure-volume-temperature (PVT) behavior based on this measurement technique is dissatisfying.

This paper presents a new measurement and quality-control system to provide analytical data of live hydrocarbons to determine the fluid composition and PVT properties in a fast and nondestructive way. Fluid measurements are performed in the laboratory or at the wellsite using a high-resolution spectrometer that covers the whole range from visible to near or mid infrared light in combination with an advanced optical sample tank or fluid transfer kit. This enables fast PVT correlations and contamination measurements without altering the fluid sample prior to the detailed laboratory measurement. The reproducibility and repeatability of the analytical system and procedure will be illustrated on performed laboratory measurements, whereas the benefits of the new technique will be discussed on first field applications.

Application of an Integrated Petrophysical Modeling to Improve Log-Based Reservoir Characterization and Oil-in-Place Estimate of a Freshwater Shaly Sand Reservoir

Sushanta Bose, Michael Myers, Peila Chen and Ganesh C. Thakur, University of Houston

We describe the application of a joint low-resistivity and saturation-height model for analyzing the log-measured resistivity of a freshwater shaly sand. Two lithologies were identified: thin beds with relatively clean interbedded sands and massive sands containing significant amounts of dispersed and structural clays. This discrimination, using a Thomas-Stieber analysis, allows for improved estimation of saturations and identifying locations of bypassed pay.

Measured reservoir porosity ranges 20 to 31% and permeability varies between 130 and 4,500 mD. As much as 30% of the measured porosity is microporosity associated with clay minerals. Rock-quality index (RQI) and flow-zone indicator (FZI) values were combined with thin section, CT scan, and mercury injection capillary pressure (MICP) data to define four rock types. The XRD and thin-section analysis showed clay content of up to 20% bulk volume with kaolinite as the dominant clay type. In the shaly zones which contain Fe-rich minerals, the grain density is significantly higher. The measured C_o-C_w data indicate cation-exchange-capacity (CEC) values of up to 0.08 meq/gm, consistent with typical values for kaolinite. The measured formation water resistivity (R_w) is ~0.82 Ω-m (~3,000 ppm NaCl). It is this low brine salinity that necessitates the use of a shaly sand model.

Thomas-Stieber analysis clearly indicates that the western area of the reservoir is characterized by laminated sands while the eastern area is dominated by massive sands containing dispersed and structural clay. This is supported by thin section, core description, and XRD.

A laminated-clay resistivity model with parallel conductors (shale layers and Archie sands) was developed for the western area. Net-to-gross (NTG) for the laminated sand was estimated from the Thomas-Stieber plot, and conductivity of the shale layers was assessed using a conductivity-NTG crossplot. This crossplot was not only used to calculate the relative contributions to the conductivity from the shale layers, but also allowed direct estimation of water saturation in the interbedded sands using the logs.

The eastern area sands have varying properties depending on the amount of dispersed and structural clays. A Waxman-Smits model was therefore applied. The cleanest sands are characterized by high porosity and permeability. These sands are however challenged by a rapid increase in water cut, interpreted to be due to streaks of high porosity and high permeability.

Leverett J-function-based saturation-height functions (SHFs) were also generated for the four different rock types. The water saturation estimated from the SHF and the log-based resistivity model both lie around 15% in the best quality rock and at 20% for the medium quality rock.

The reservoir characterization and oil in-place estimation were significantly improved by implementing this 'shaly sand' petrophysical analysis tailored to the amount and distribution of the clays. The results obtained were used to improve the static model and a corresponding new simulation study that was able to identify potential infill areas in this mature reservoir.

Building a Reservoir Rock Dielectric-Properties Database

Matthew Josh and Ben Clennell, CSIRO

Measurements of rock dielectric properties can help to quantify porosity, mineralogy, clay content, texture and especially water saturation of reservoir rocks. Permittivity in the range of MHz to GHz, which can be measured rapidly using downhole tools and also in the laboratory, offers insights into rock flow and mechanical properties not only for conventional reservoirs, but also for tight reservoirs and overburden shales. One barrier to the wider acceptance and adoption of dielectric logging has been the scarcity of laboratory measurements on a range of standard rock types at controlled saturation levels that are verified with independent methods. A second limitation is the lack of well-understood and calibrated models for the interpretation and inversion of advanced, multifrequency permittivity and conductivity logs.

For several years, CSIRO has been at the forefront of developing practical methods for measuring the dielectric properties of intact rocks, cuttings and fluids, but much of our recent work has focused on shales and other tight rocks. We are now embarking on a program to collect standardized dielectric spectroscopy data on a library of different rock types obtained from sources worldwide. The library of available samples includes a diversity of carbonate and clastic formations having a wide range of texture, porosity and permeability. We present examples of the data collected so far on typical clean sandstones and carbonates as a function of brine saturation, and for a number of different brine salinities. We also show how these data are tied into standard core analysis results, 2D (SEM) and 3D (micro-CT) petrography, and critically, how it can be cross-matched with NMR T_2 distributions measured in the same rocks across the full range of saturations. These are the initial steps in building up a comprehensive database of measurements for pore volume- and saturation-controlled dielectric permittivity and effective conductivity from 10 MHz to 1 GHz in combination with the NMR response.

The combined dataset can be used to build, test and improve upon, dielectric rock physics models based either on effective-medium theory or on solutions of electrodynamic equations in 3D digital rocks. We show examples of data matching for forward models computed using a modified Hanai-Bruggeman equation in an incremental effective-medium method, and with the new 3D method of direct solution implemented in the Data Constrained Modeling (DCM) environment. While the more advanced DCM outputs are more accurate for ab-initio property computations where the rock microstructure is known and can be populated with true 3D distributions of solid minerals and fluids, the simpler effective-medium models are much faster and more practical for use in inversions to obtain rock type and saturations from log data.

Calculating Porosity and Permeability of Miniplugs From a Low-Resistivity/Low-Contrast Hydrocarbon Reservoir Using Digital Core Analysis

Hijaz Kamal Hasnan, University of Malaya

Low-resistivity/low-contrast (LRLC) hydrocarbon reservoirs are increasingly targeted for hydrocarbon production due to their relative abundance as conventional sandstone reservoirs become scarcer. However, determining the petrophysical properties, such as fluid saturations, hydrocarbon content and permeability, is challenging in LRLC reservoirs due to thin and alternating layers of sandstone, mudstones and siltstones which cannot be resolved by well logs As a result, well logs tend to average out the variable properties, often neglecting the highest-quality layers, and thus underestimating net pay and hydrocarbon saturation. Developing LRLC hydrocarbon reservoirs requires an analysis of multiscale flow properties to reduce uncertainty in hydrocarbon reserves estimation. To date, properties at millimeter and centimeter scales are less examined in reservoir characterization and modeling due to the limited resolution of well-logging tools used to measure flow properties. This study uses X-ray micro-CT (XMCT) and digital core analysis (DCA) software to calculate porosity and permeability of thin sandstone beddings within core plugs from a Malaysian LRLC reservoir. Miniplugs extracted from the core plugs are imaged in 3D using XMCT and the porosity and permeability are calculated using DCA software. Four of the five miniplugs indicate significantly higher permeability than their corresponding core-plug permeability measured using conventional routine core analysis (RCA). Meanwhile, the calculated porosity using DCA is consistent with RCA results. Further studies are required to upscale small-scale flow properties of different LRLC rocks to reservoir-scale to investigate their effects on effective flow properties and hydrocarbon reserves. This study shows the ability XMCT and DCA to resolve and reconstruct micron-scale pore networks of reservoirs rocks to calculate petrophysical properties at very small scales that could contribute to multiscale characterization of hydrocarbon reservoirs with small-scale heterogeneity.

Combining Logging-While-Drilling (LWD) Resistivity and Capture Sigma to Identify and Evaluate Waterflood Encroachment—Case Study of a Field With Multilayered, Complex Reservoirs

Doug Murray, Schlumberger; Miguel Ascanio, Matthew Hoehn and Patrick Garrow, Chevron

This study focuses on field development where stacked reservoir layers are undergoing secondary recovery via water injection. Certain reservoir layers experience significant waterflooding, while other layers experience little to no flooding. Historical evaluation approaches to understand water encroachment involve production logging and/or production tests. Both approaches are expensive in terms of lost production and data acquisition.

Waterflooded reservoirs contain an unknown mixture of connate and injected water. As such, fixed water salinities cannot be assumed in water-saturation computations. Water production is a concern, only reservoir layers with hydrocarbon volumes greater than a predetermined cutoff are to be completed.

During the infield drilling program, an innovative approach to enhance reservoir understanding with log data acquired while drilling was implemented to compute water salinities and saturations across the stacked layers. LWD data acquired while drilling experiences limited drilling fluid invasion such that relatively shallow depth-of-investigation (DOI) measurements, such as capture sigma, which are sensitive to reservoir fluid chlorine content, can be used to estimate water saturation in environments of known formation water salinity. Likewise, Archie-based resistivity-based approaches can also be used to compute water saturation when water salinity is known.

In this paper, we use LWD logs acquired on multiple wells acquired across multiple layers to demonstrate a simultaneous inversion of sigma and resistivity to evaluate reservoir water salinity and saturation. In these examples the reservoir environment consists of unknown and/or mixed water salinity. We show that the simultaneous inversion approach correctly identifies changes in formation water salinity and saturation while the conventional resistivity approach overestimates hydrocarbon saturation and can lead to errors in the completion of zones with high water cut.

Core-Log-Geomodel Integration: Advanced Classification and Propagation Workflows for the Consistent, Rigorous, and Practical Upscaling of Petrophysical Properties

A.A. Curtis and E. Eslinger, eGAMLS Inc.; S. Nookala, Cerone Pvt Ltd

An improved procedure for reservoir characterization is presented that focuses on the integration of core and wireline log data for the development of geocellular models. Concepts that clarify the reservoir characterization problem are explained and the scales that are important to developing a tractable solution are defined. Workflows are presented illustrating how both basic (static) and saturation-dependent (dynamic) petrophysical properties may be moved from one scale to the other. The similarities and the differences in the procedures at each scale are described. In addition, an explanation is given as to why a multiscale approach involves far more than just upscaling, as is often assumed. Examples are given at various scales of what a comprehensive multiscale approach entails.

The need for five major reservoir characterization steps at every scale change of the multiscale characterization workflow is explained. These steps are: Classification, Selection, Evaluation, Propagation, and Upscaling. Each step is vital in securing a robust suite of petrophysical properties at the succeeding larger scale, with each step being covered in detail. Recognizing the distinctiveness of each step also leads to the ability to improve any step independently. The methodology is applicable at the core-plug-scale—where petrophysical properties are derived—and is then carried through the wireline log petrophysical-scale to the geomodelling-scale and ultimately to the simulation-scale. The difficulty of ensuring a rigorous characterization at the 1D wireline log-scale, especially of saturation-dependent properties, is explained and a consistent and robust solution is provided.

Workflows that have proved effective at selected scales in both siliciclastic and carbonate reservoirs are presented to illustrate the five steps of the methodology. Examples of what constitutes effective Classification are provided and are used to illustrate why the probabilistic (Bayesian-based) multivariate classification procedure that has been adopted is highly desirable at all scales and necessary at some. The importance of the Selection of representative fine-scale samples is stressed, and the constraints surrounding the Evaluation of properties at each fine scale are explained. The critical step of the Propagation (distribution) of the petrophysical properties derived at the fine-scale into the coarse-scale volume using the Bayesian probabilistic model is illustrated as it is essential to the success of the workflows. Finally, the use of appropriate Upscaling technologies at each scale is stressed. An explanation is provided of how the Classification, Selection, Evaluation, Propagation, and Upscaling steps should be adapted for any given project scale.

The paper introduces workflows that have been developed over many years to overcome some of the more intractable elements of the overall reservoir characterization process, particularly the Classification and Propagation of saturation-dependent properties. These workflows have been applied at various scales in reservoir studies and are continuing to be developed because of the resulting successes. The workflows are comprehensive, consistent, and rigorous in their specification and implementation, but also are simple enough in their design to permit them to be embraced by all disciplines involved in the reservoir characterization process.

Digital Rock Technology for Accelerated RCA and SCAL: Application Envelope and Required Corrections

Nishank Saxena, Justin Freeman, Amie Hows, Ronny Hofmann, Faruk O. Omer and Matthias Appel, Shell

Digital rock physics (DRP) is a rapidly advancing image-based technology for predicting subsurface properties of complex rocks (e.g., porosity, permeability, formation factor) to achieve more, cheaper, and faster results as compared to conventional laboratory measurements (RCA and SCAL). This is possible since DRP analyses can be carried out on a small piece of rock (< 1 cm^3) that can come from whole core, sidewall core, or a drill cutting, using state-of-the-art micro-CT technology and novel digital approaches. However, for this technology to mature, it is important to demonstrate that it is feasible to estimate two of the most fundamental rock properties, porosity and permeability. Shell has recently performed a series of detailed studies to benchmark commercially available digital rock tools. The conclusion of these studies is that present technology consistently underestimates porosity (in our study by as much as 6 p.u.) and overestimates permeability (by a factor of 10 or more in some cases) for reservoir rocks. At this level of accuracy, DRP is not considered a viable alternative to RCA and SCAL.

Reliable measurements of porosity are critical for hydrocarbon reserve estimation and are important for establishing rock-property trends, such as permeability versus porosity. For example, underestimating porosity by 4 p.u. in a 10 p.u. rock can make a conventional tight gas field uneconomic, resulting in a lost opportunity. Similarly, underestimating porosity of an unconsolidated reservoir rock can significantly overestimate sand strength, leading to suboptimal sand-control schemes and a subsequent requirement to retrofit. In deepwater wells this may be prohibitively expensive. Similarly, overestimating permeability by a factor 10 can be disastrous from the point of view of project economics for tight gas or deepwater fields.

Through our studies we understand how a combination of limited image resolution, biased segmentation of images with coarse resolution, and a finite field of view, lead to the systematic underestimation of porosity and overestimation of permeability calculated using DRP. The primary cause of the discrepancy between image-derived and laboratory-measured properties is constraints on image acquisition. Micro-CT scanners are typically limited to an effective image resolution of approximately 2 μm and field of view of about $2{,}000^3$ voxels. We can quantify these effects, and thus derive correction factors directly from the image. Unless these corrections are applied to the DRP-computed properties, the simulation results will not be comparable to laboratory measurements. These novel proprietary solutions allow us to deploy DRP as a technology for integrated reservoir modeling in existing and future conventional sandstone and carbonate reservoirs.

Discovery of New Horizons in a 36-Year Old Conventional Oil and Gas Play by Use of State-of-the-Art Formation Evaluation Approaches: A Case Study From Thrace Basin, Turkey

Murat Fatih Tuğan and Ugur Yuce, TPAO

Due to relatively low hydrocarbon prices in recent years, making the most out of each well become crucial to increase the profit margins of oil and gas companies, hence they can maintain investing on exploration and production (E&P) activities. Discovery and delineation of new prospective zones in pre-existing wells is the quickest, cheapest and most efficient way to strengthen the economics of oil and gas companies.

In this study, a very successful formation evaluation case study will be discussed which totally changed the destiny of a conventional play. By re-evaluation of formations via use of a low-resistivity pay approach firstly, new gas zones have been discovered in a pre-existing gas well drilled in 2006 (Yesilgol-O1), which is on the verge of abandonment. Furthermore, the experience in this well opened a new horizon for a nearby oil well (Yesilgol-1), which never produced at economic rates after it was drilled in 1982 to produce deeper oil-bearing zones. In order to monitor the current saturation of the shallow gas reservoir in this well, a pulsed-neutron logging operation has been performed. Its interpretation has been supported by five different data sources (seismic cross sections, lithology recordings and X-ray diffraction (XRD) analysis of drill cuttings, gas readings in mud logging unit (MLU), sonic (DT) and deep resistivity (LLD) logs recorded in openhole well). As a result of this work, new reservoir intervals have been discovered in this 36-year old well with considerably high gas rates.

This case study involves integration of various data sources and use of state-of-the-art approaches for a successful formation evaluation, especially in thin beds, low-contrast pay zones and previously bypassed hydrocarbon-bearing zones. Last but not the least, the most important factor in the success of this work is the robust, inclusionary project-management approach to integrate different disciplines and make them all focus on the ultimate goal.

Diverse Fluid Gradients Associated With Biodegradation of Crude Oil

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Severe biodegradation of crude oil is widely known to increase viscosity quite significantly. Water washing is shown contribute to this increase under some circumstances. What has been less understood is the spatial variation of viscosity in reservoirs that is caused by biodegradation. Biodegradation-induced gradients are expected because the microbes live in water and consume oil at the oil-water contact (OWC), thus, biodegradation is far from uniform in the oil column. Case studies reviewed here show that reservoirs with biodegraded crude oil can have large viscosity gradients at/near the oil-water contact (OWC), or no variation of viscosity or variations of viscosity at the top of the oil column. These entirely different outcomes depend on reservoir fluid geodynamic (RFG) processes that occur in conjunction with biodegradation. The combination of downhole fluid analysis and geochemical analysis is shown to delineate the particular RFG processes that control viscosity variations associated with biodegradation. The extent of spill-fill and the evolution of biodegradation is of particular concern. In addition, diffusive mixing can minimize viscosity gradients from biodegradation and depends strongly on overall distance from the OWC, and thus depends on tilt angle of the reservoir. In addition, reservoir temperature is important in that biodegradation ceases above 80°C. The different case studies presented herein account for the dominant viscosity profiles associated with biodegradation and provide guidance for optimal reservoir evaluations.

Downhole Neutron-Spectroscopy Element and Mineral Estimates Compared to a Ring Tested Core Reference

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The of advanced measurements, such as neutron-induced spectroscopy is important when characterizing complex networks. It infers dry-weight elements from inelastic- and capture-neutron gamma-ray spectra. Subsequently, using the dry-weight elements as input to multimineral log analysis, mineral fractions are estimated. There are many benefits in having the accurate minerals characterized when doing formation evaluation. One benefit is improved geomodel inputs like volume of shale, net/gross, porosity, and permeability. It was shown previously that improvements in these inputs can alter modeled in-place oil volumes and reserves significantly. Other benefits include improved pore pressure predictions, better inputs to fluid substitutions and rock mechanical models. Due to this, AkerBP started a comprehensive study, comparing downhole log-based dry-weight elements and mineral fractions to core-laboratory XRF, XRD, EDX-SEM and FTIR measurements. The motivation was to increase confidence in this technology.

Neutron-induced spectroscopy logs were run in three wells through a mineralogically complex sedimentary sequence of Jurrasic and Triassic age in the Norwegian North Sea, and were subsequently compared to reservoir core data in the same wells. The core plugs (62 samples) were drilled perpendicular to bedding plane, and split in three sectors along the center plug axis. The plug material was sent to three laboratories (commercial and academic) for chemical (XRF, EDX-SEM) and mineral (XRD) analysis. The dry-weight elements and mineral mass fractions from multimineral log analysis (ELAN) were compared to these ring-tested laboratory results.

A critical step in the validation of log data from core is to ensure that core data can be taken as an accurate 'ground-truth'. Blind-test samples with known mineral concentrations were sent to all laboratories to assess accuracy. This provided an estimate of interlaboratory deviation (e.g., 2-sigma standard deviation) of the geochemical and mineralogical measurements. The deviation of the blind-test XRD results was surprisingly large. For example, kaolinite and montmorillonite deviated by ~9% w/w. One laboratory showed high accuracy for all blind-test analyses. XRD has potential to be accurate, but is highly dependent on the laboratory XRD procedures and skill of the operator performing the analysis. A similar blind test was also performed for XRF measurements, with interlaboratory deviation for the abundant rock-forming elements of ~2% w/w.

The agreement between log elemental dry-weights and average of the XRF elemental concentrations at the corresponding depths was determined to be good. Log mineral fractions were estimated by three methods: (1) radial basic function, (2) multiple linear regression, and (3) multimineral ELAN. We compared these three methods to each other, to the individual laboratories and to the average of the XRD mineral mass fractions. The agreement at all 62 core depths was determined to be good, well within the deviation of the core mineralogy measurements. The careful validation of downhole log measurements from independent core studies provides confidence in the use of advanced neutron-induced spectroscopy logs for petrophysical interpretation of formation minerals in complex reservoirs, such as offshore Norway.

Estimating Capillary Pressure From NMR Measurements Using a Pore-Size-Dependent Fluid Substitution Method

You Wang, David Medellin and Carlos Torres-Verdín, The University of Texas at Austin

Capillary pressure is an important property necessary to quantify fluid transport in rocks, and is widely used to assess pressure seal capacity, transition-zone thickness, and free-water-hydrocarbon depth, among other important reservoir conditions. Capillary pressure curves are commonly measured in the laboratory through mercury-injection (MICP), porous-plate, or centrifuge methods. The MICP method is destructive, whereby often nondestructive techniques, such as the centrifuge or porous-plate methods, are preferred to perform multiple collocated core measurements. The aforementioned methods, however, are expensive and time-consuming because they must be performed under very restrictive laboratory conditions. Alternatives such as NMR-based methods have been developed for the same purpose, but only apply to fully water-saturated rocks. In practice, however, reservoir rocks can include both water and hydrocarbon, which makes these methods impractical.

We introduce a workflow to calculate capillary pressure curves from NMR T_2 distributions of partially oil saturated measurements: First, we develop a pore-size-dependent fluid-substitution (PSDFS) joint inversion method to correct transverse relaxation time (T_2) distributions for the hydrocarbon effect in partially oil-saturated rocks. A PSDFS joint inversion on the T_2 distributions of different oil-saturated levels is used to estimate irreducible water saturation and reconstruct the fully water-saturated T_2 distribution. Next, we convert the T_2 distribution to pore-size distribution using a measured or estimated surface relaxivity. Finally, using a reliable correlation between pore and throat-size distributions, we estimate the capillary pressure curve from the cumulative porosity derived from the measured and fluid-substituted fully water-saturated T_2 distributions.

This study includes validation of the PSDFS joint inversion method and the application of the workflow with laboratory measurements. For the validation, we acquire NMR data for a synthetic pore-size distribution with different values of oil saturation. Applying PSDFS joint inversion on the measuremeants yields the best PSDFS parameters, which makes it possible to calculate the fully water-saturated T_2 distribution from partially oil-saturated T_2 distributions. The feasibility of our joint inversion method is confirmed by comparing the calculated fully-water-saturated T_2 distribution to the T_2 distribution of the synthetic fully water-saturated pore-size distribution. We apply the workflow to sandstone and carbonate samples, where a DDIF-CPMG pulse sequence is used to acquire the NMR measurements at different saturations of water and oil. We derive the capillary pressure curve from the measured and fluid-substituted fully water-saturated T_2 distributions and compare them to MICP and centrifuge measurements.

The workflow is limited to water-wet rocks with negligible internal field gradients for which a correlation between pore- and throat-size exists. Consequently, it is not well suited for complex pore networks with mixed wettability. Additionally, in low-permeability rocks, a low signal-to-noise ratio together with uncertainty in pore- and throat-size determination due to NMR tool ringing and echo-time limitations can impact the determination of capillary pressure curves.

Despite these limitations, the NMR fluid-substitution-derived capillary pressure curves show a good match with MICP and centrifuge measurements, thereby successfully verifying that our NMR FS-based method enables the estimation of capillary pressure curves from NMR data of partially oil-saturated rocks.

Experimental Estimation of Relative Permeabilities Using X-Ray Computed Tomography

Andrés Felipe Ortiz, Edwar Herrera Otero, Nicolás Santos Santos and Luis Felipe Carillo, Universidad Industrial de Santander

Through the mechanical integration of an X-ray computed tomography (CT) scanner and a coreflooding system, tomography images can be obtained, during all the time of performing a water-injection experiment on a rock sample. These images are used to estimate in-situ saturation profiles, therefore, the movement of the displacement front and the distribution of the fluids in the different stages can be seen.

A computational tool is implemented that allows simulation and automatic history match, of the experimental differential pressure, the production of the phases and the saturation profiles calculated with CT. This software is programmed in Matlab and it uses numerical optimization methods to minimize the difference between the observed and the simulated data.

The method can be used to analyze any unsteady-state experiment of relative permeabilities and it does not present the restrictions of other classical analysis methods, such as the JBN. Additionally, tomography allows to see the flow of fluids inside any type of rock, it is fast, precise, exact, and due to the configuration implemented in this work, it is possible to work under reservoir pressure and temperature conditions (up to 10,000 psi and 150°C).

The results indicate that including saturation profiles in the calculation can be useful to improve the accuracy of the estimated relative permeabilities. Similarly, it is found that the history-matching approach offers remarkable strengths over traditional methods, such as the JBN. It is determined that the estimated saturations by means of tomography present errors lower than 3% in comparison with the material balance. The application of this technology produces a better and easier estimation of the relative permeabilities, reduction of the uncertainty in the predictions about the performance of the reservoir. The visualization of the displacement font improves the qualitative understanding of the phenomena related to fluid flow in porous media.

Fast Forward Modeling of Borehole Nuclear Magnetic Resonance Measurements in Vertical Wells

Mohammad Albusairi and Carlos Torres-Verdín, University of Texas at Austin

Nuclear magnetic resonance (NMR) logs are widely used to characterize in-situ rock and fluid properties. The vertical resolution is mainly controlled by the antenna length, logging speed, sequence-dependent signal-to-noise ratio (SNR) and mud/formation electrical conductivity. To overcome SNR limitations, signal depth-stacking is used to improve measurements accuracy at the expense of vertical resolution. Hence, borehole NMR measurements suffer from considerable spatial averaging of formation properties, especially in thinly bedded rocks, causing a significant uncertainty in the petrophysical interpretation. Also, electrically conductive formations and mud-filtrate invasion can influence the petrophysical properties estimated from NMR logs. The implementation of forward modeling and inversion techniques can capture and quantify the shoulder-bed, invasion and environmental effects in spatially complex rock formations and permit a reliable interpretation. However, the computation time required to invoke the forward model restricts the use of inversion methods. Fast and accurate forward methods can overcome these limitations and allow a more reliable quantification of spatially variable formation properties.

We develop a new fast and accurate forward algorithm using spatial sensitivity functions (SSF), which are calculated from first-order perturbation theory. The SSF quantify NMR porosity dependence on spatial formation property perturbation with respect to a reference formation. The discrete adjoint method (DAE) is employed to efficiently calculate the SSF with two simulations runs only, the reference and the adjoint solutions respectively. We generate a library of precomputed first-order linear SSF in homogenous reference formations to rapidly simulate NMR magnetization decay in complex environments with variable fluid and rock properties. We develop a three-dimensional (3D) multiphysics forward model that includes NMR tool characteristics, magnetization evolution, and electromagnetics (static and radio-frequency) propagation to derive tool sensitivity maps. Finite-element method (FEM) is used to calculate the magnetic fields, and then the NMR sequence-dependent magnetization decay is evaluated using Bloch-Torrey equations. We apply the SSF-derived forward approximation to a series of synthetic cases in a vertical well, that include thin layers, variable fluid, and rock properties, and mud-filtrate invaded formations. We validate the accuracy of the fast forward model through comparison with analytical models and the multiphysics forward tool.

Results show that NMR sensitivity depends on two formation properties (porosity and electrical conductivity), NMR pulsing-sequence, tool geometry, and borehole/mud properties. The sensitivity functions to formation porosity are controlled by the reference mud/formation electrical conductivity and not the reference formation porosity. Therefore, one SSF can be used to approximate NMR response in a layered formation with low-contrast resistivity. Analysis of a wide range of examples confirms that the proposed forward approximation can be computed in a few central processing units (CPU) seconds with maximum relative errors of 4%. The SSF-derived forward routine constitutes a fast, reliable and efficient alternative for accurate modeling and interpretation of NMR logs acquired in complex environments.

Heterogeneity in the Petrophysical Properties of Carbonate Reservoirs in Tal Block

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Exploring for a wide range of hydrocarbon reservoirs, including carbonate systems is increasingly important in times of higher resource demand and progressively dwindling reserves.

Exploration for carbonate systems is generally more difficult than siliciclastic reservoir exploration because of intrinsic heterogeneities, which occur at all scales of observation and measurement. Heterogeneity in carbonates can be attributed to variable lithology, chemistry/mineralogy, pore types, pore connectivity, and sedimentary facies. These intrinsic complexities can be related to geological processes controlling carbonate production and deposition, and to changes during their subsequent diagenesis. The term “heterogeneity” is rarely defined and almost never numerically quantified in petrophysical analysis, although it is widely stated that carbonate heterogeneities are poorly understood.

This work in carbonates of the Tal block has investigated how heterogeneity can be defined and how we can quantify this term by describing a range of statistical heterogeneity measures (e.g., Lorenz and Dykstra-Parsons coefficients). These measures can be used to interpret variation in wireline log data, allowing for comparison of their heterogeneities within individual and multiple reservoir units. Through this investigation, the Heterogeneity Log has been developed by applying these techniques to wireline log data, over set intervals of 10, 5, 2 and 1 m, through a carbonate reservoir.

Application to petrophysical rock characterization shows a strong relationship to underlying geological heterogeneities in carbonate facies, mud content and porosity (primary and secondary porosities) in the Tal block. Zones of heterogeneity identified through the successions show strong correlation to fluid-flow zones. By applying the same statistical measures of heterogeneity to established flow zones it is possible to rank these units in terms of their internal heterogeneity. Both increased and decreased heterogeneity are documented with high reservoir quality in different wireline measurements; this can be related to underlying geological heterogeneities. Heterogeneity Logs can be used as a visual indicator of where to focus sampling strategies to ensure intrinsic variabilities are captured.

Carbonate lithology and mineralogy can be highly variable, both vertically and horizontally through a succession. Carbonate depositional environments produce a diverse range of sedimentary facies, which contain different porosity types with varying degrees of connectivity, producing complex and irregular pore networks. Minerals, such as calcite, aragonite, and dolomite may coexist within a single rock unit in varying proportions. Carbonate minerals have different stabilities and are susceptible to the many post-depositional processes of diagenesis.

This study, therefore, focuses on developing these techniques and applying them to carbonate petrophysical and geological data including borehole image and core data in the Tal block, which can have further application to characterizing poro-perm relationships, fluid-flow zone identification and sampling strategies.

Improving Productivity Estimation in Development Wells Using LWD Formation Testers and Geochemical Logs

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Accurate estimation of oil and gas productivity in development wells is crucial for perforation decisions and planning for future development activity. The production capacity of a well can be described by the productivity index (PI), which is mainly determined by the effective permeability to the mobile fluid phase. In exploration wells, PI is usually estimated from drillstem tests (DST), which record the flow rate of the reservoir section isolated for production. In development wells, however, DSTs are typically scarce, and the well PI must be estimated from well logs.

The log-based permeability model, K-Lambda, estimates the absolute permeability (k) from mineral abundances, which in turn are derived from geochemical logs. The model associates a specific surface area (*S0*) with each lithology to calculate the permeability from the surface area-to-volume ratio of the rock. In general, *S0* for sand and carbonate are well defined and stable. However, *S0* for clay depends largely on the clay type and varies from reservoir to reservoir. Since clay has the most significant effect on permeability, correctly accounting for its surface area is key to improving the prediction accuracy.

This paper describes a workflow to improve PI estimation in development wells by calibrating the clay *S0* parameter with fluid mobility, which is estimated from formation pressure pretests. Since the pretest mobility is defined as the effective permeability to the mud filtrate over its viscosity, the pretest effective permeability in water-based mud (k_w) must first be converted to absolute k before it can be used in the calibration process. The conversion relies on relative permeability k_{rw} measurements on core samples as $k_{rw} = k_w/k$. Once the calibrated K-Lambda permeability log is obtained, we use it to improve PI estimation in development wells. The workflow consists of the following steps:

1. Establish a relationship between k and effective permeability to water (k_w) at irreducible oil saturation (S_{or}), using relative permeability measurements on core samples from the exploration (or development) well. Alternative methods are also discussed.
2. Using the relationship in Step 1, convert the measured pretest permeability at discrete points from k_w to k (assuming water-based mud).
3. Calibrate clay *S0* in the K-Lambda model for each pay sand with the converted k at the pretest points and compute a continuous k log with the calibrated model.
4. Compute the relative permeability logs to water (k_{rw}) and oil (k_{ro}) from known correlations. Then, calculate the continuous effective permeability to oil (k_o) as $k*k_{ro}$.
5. Calculate PI in the development well from k_o using the testing data in exploration wells as a reference.

This workflow is demonstrated using formation pressure tests and geochemical logs acquired by LWD tools in an offshore siliciclastic brownfield. The productivity estimation from this workflow shows excellent agreement with actual production data in the test wells.

Integrated Multiphysics Workflow for Automatic Rock Classification and Formation Evaluation Using Multiscale Image Analysis and Conventional Well Logs

Andres Gonzalez and Zoya Heidari, The University of Texas At Austin; Olivier Lopez and Harry Brandsen, Equinor

Conventional well-log-based rock classification often overlooks rock fabric features (spatial distribution of solid/fluid rock components), which makes them not comparable against geologic facies, especially in formations with complex rock fabric. This also affects reliability of formation evaluation and completion decisions, which require rock types as inputs. Multiphysics and multiscale images of core samples and formation (e.g., CT-scan, image logs, core photos) can capture fabric-related, depositional, and geological features. However, automatic integration of multiscale and multiphysics image data and conventional well logs for enhanced rock classification and its incorporation into well-log-based formation evaluation can be challenging. In this paper, we propose an automatic workflow for joint interpretation of conventional well logs, CT-scan/core images, and image logs for simultaneously optimizing rock classification and formation evaluation.

The objectives of this paper include (a) to improve completion-oriented rock classification and to optimize the number of rock classes by integrating rock fabric features obtained from core photos, CT-Scan images, and image logs with rock physics properties obtained from conventional well logs, (b) to use the outcomes of rock classification for class-by-class-based formation evaluation for enhanced assessment of petrophysical properties, and (c) to extend the developed workflow to noncored wells.

First, we perform conventional well-log interpretation to obtain petrophysical and compositional properties of the evaluated depth intervals. Subsequently, we use our recently developed workflow for automatic extraction of rock-fabric-related features derived from multiscale image data (core photos, CT-scans, and image logs). Then, we use the estimated petrophyisical/compositional and fabric-related properties to perform rock classification. We update rock physics models in each rock class and repeat the formation evaluation. The updated formation properties are used in the next iteration for rock classification and formation evaluation, while minimizing a physics-based cost function to optimize the number of rock classes.

We successfully applied the proposed workflow to a siliciclastic sequence with complex fabric and pore structure. Dual-energy acquired CT-scan images were available along with image logs, core photos, standard core analysis data, and conventional logs. Comparison between automatically derived rock classes and lithofacies revealed that the proposed workflow can automatically detect lithofacies with an error of less than 15% where core images were available. The rock types were estimated consistently in noncored wells. We also observed an improvement in rock classification results compared to those obtained from core-based and conventional well-log-based rock classification methods. Furthermore, the estimated optimum number of rock classes was in agreement with the previously identified lithofacies. Including the outcomes of integrated rock classification in the formation evaluation workflow significantly improved estimates of permeability and porosity. A unique advantage of the proposed workflow compared to previously documented rock classification methods is that the introduced method not only extracts rock fabric features from image data using image analysis, but also incorporates rock physics from image and conventional logs in rock classification and formation evaluation. The presence of rock fabric features in the rock classification workflow enhances completion-oriented rock typing. It also enhances rock physics models developed for each rock class which, improves formation evaluation outcomes.

Integrated Reservoir and Source-Rock Characterization: Refined Downhole Analyses Through Advanced Surface-Logging Technology

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Organic and mineral geochemistry can be of priceless importance for petroleum system assessment and reservoir characterization, especially when integrated with other disciplines, such as formation evaluation and sequence stratigraphy. Identifying key geochemical changes within lithology refines what traditional approaches to reservoir characterization are not able to provide.

The following study shows how the integration of several formation evaluation technologies from advanced surface logging (ASL) to logging while drilling (LWD) and wireline (WL) lead to the characterization of a complex reservoir system compartmentalized by an active structural setting. The formation consists of interstratified dolomite, limestone and sandstone with strong diagenesis overprint covered by shale deposits that play the double role of source rock and seal. The carbonate units represent most of the pay zones and hold a complex fluid column governed by multiple paleo-contacts with a thick imbibition zone.

ASL organic geochemistry (TOC and pyrolysis) has permitted the source-rock zonation in terms of quality and maturity; furthermore, when integrated with NMR logs, it identified the best candidate layers for the generation of hydrocarbons.

ASL inorganic (XRF/XRD) and organic (thermal desorption gas chromatography, TD-GC) geochemistry along with mud-gas analyses, have permitted a fine zonation of the reservoir interval in four sections. The combination with LWD logs and WL nuclear magnetic resonance revealed the mechanisms governing such geochemical differences: two related to distinct compartments of the main hydrocarbon accumulation and two others to the oil-water transition and the imbibed water zone.

Furthermore, the joint interpretation of rock textures with elemental patterns is a good driver to identify different diagenetic degrees. In carbonates, the vicarious elements of Ca (Calcium), Na (Sodium) and Strontium (Sr), such as magnesium (Mg), manganese (Mn), zinc (Zn) and iron (Fe) help to identify the different types of cement and matrix (sparite and micrite). The correlation of these elemental diagenetic proxies, with XRD, TD-GC, resistivity and porosity logs refined the petrophysical assessment and helped the identification of the most productive layers for an optimal well completion.

This paper demonstrates how ASL geochemistry contributes in various ways to the fine description of reservoir geology, when integrated with LWD and WL, it allows the characterization of organic facies, the evaluation of rock petrophysics with its diagenetic overprint, the zonation of an entire fluid column along with the governing processes of saturation and, ultimately, the identification of productive layers.

Interpreting Pore Structure and Permeability From NMR T_2 Spectrum Based on a Pore-Throat Model

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Generally, the pore geometry could be identified by combining the pore model and nuclear magnetic resonance (NMR) techniques, and the pore space is often considered as pure spherical pore or capillary bundle. However, both throats and pores exist in real rocks, which dominate the connectivity and storage capacity, respectively, the simple pure spherical pore or capillary model could not accurately describe the complex pore-throat structure. Therefore, a pore-throat model is proposed to illustrate the complex pore-throat structure, which is characterized by two parameters: the throat tortuosity, τ, and throat-to-pore radius ratio, *Cd*. By incorporating the pore-throat model into the NMR model, the NMR response characteristics are closely related to pore-throat structure. By adjusting pore-structure parameters τ and *Cd* to minimize the mean-squares deviation between the fitting signal and the measured signal, the optimal solution for spectrum could be determined. Moreover, total T_2 spectrum can be further decomposed into pore and throat spectra, which reflect the distribution characteristics of pores and throats. According to throat-spectrum distribution and tortuosity characteristics, the permeability property can be analyzed and explained. It demonstrates that when the throat spectrum distributes in a long relaxation time and the tortuosity is small, meso- or macrothroats are developed and pore structure is simple, hence the connectivity and permeability of the formation are favorable for oil and gas production. On the other hand, it also reveals that the large tortuosity may lead to more complex pore structure and low permeability. By applying this method to real cases, the analysis results are consistent with the permeability property, which verifies its validity.

Multifrequency Interpretation of Electric Resistivity and Dielectric Permittivity Measurements for Simultaneous Assessment of Porosity, Water Saturation, and Wettability

Artur Posenato Garcia and Zoya Heidari, The University of Texas at Austin

Broadband electrical-resistivity and dielectric-permittivity measurements are affected by combined effects of rock fabric, composition, fluid saturation and distribution, and interfacial polarization mechanisms. An integrated multifrequency interpretation of electrical measurements can provide information about the dominant polarization mechanisms, which are linked to grain size, solid-fluid interfacial properties, porosity, fluid saturations, and wettability. Previous publications quantified the influence of these important reservoir properties on broadband resistivity/permittivity-dispersion data and introduced interpretation models and correlations. However, a physics-based interpretation workflow for simultaneous assessment of these properties, including wettability, uniquely from multifrequency interpretation of electric measurements is not available. In this work, we propose to narrow down the knowledge gap in interpretation of broadband dielectric measurements in water-, oil-, and mixed-wet formations by introducing a new interpretation workflow for simultaneous assessment of porosity, fluid saturations, and wettability.

The objectives of this paper include (a) to introduce a new rock physics model for broadband characterization of dielectric measurements incorporating the combined effects of grain size, porosity, water saturation, wettability, and interfacial polarization, and (b) to develop a new interpretation workflow based on an inversion algorithm capable of simultaneously estimating porosity, water saturation, and wettability of the formation uniquely from multifrequency electrical-resistivity and dielectric-permittivity measurements.

We introduce a rock-physics model for broadband characterization of permittivity measurements by integrating a mechanistic model of electrolyte-solid interfacial polarization, on water- and oil-wet grains, with bulk properties of fluids and grains. Then, we develop a new interpretation workflow for estimating porosity, fluid saturations, and wettability of the formation. These properties are obtained by minimizing an objective function using a downhill simplex method. The objective function is defined by the Euclidean norm of the difference between the complex multifrequency dielectric permittivity measured experimentally and the ones estimated with the new rock-physics model for the frequency interval encompassing the response of the dominant polarization mechanisms. We also include a regularization term in the objective function to improve the robustness of the inversion algorithm. This term is a function of the energy of the dielectric-permittivity measurements and the expected variance of the experimental noise.

We successfully applied the introduced interpretation workflow to multifrequency electrical-resistivity/permittivity measurements performed on six carbonate and sandstone rock types at different wettability conditions and different levels of water saturation. The experimental measurements of complex resistivity/permittivity, performed in the frequency interval from 1kHz to 1GHz, are in agreement with values obtained from the proposed analytical workflow. Finally, wettability, saturation, and porosity of the samples were simultaneously estimated with relative errors less than 25% by applying the new interpretation workflow. The wettability indices estimated from the introduced workflow agreed well with wettability-indices obtained from USBM and Amott-Harvey methods. It should also be noted that all the parameters required by the introduced workflow are associated with physical mechanisms at microscopic- and pore-scale domains or realistic and quantitative pore geometry features of the rock. A unique contribution of the new workflow is that it honors rock fabric and minimizes the need for extensive calibration efforts.

NMR Measurement of Porosity and Density From Drill Cutting of

Unconventional Tight Reservoirs

Stacey M. Althaus, Jin-Hong Chen and Jilin Zhang, Aramco Services Company

Petrophysical data, essential for reservoir description and modeling, are obtained by expensive laboratory core measurements and/or well-log measurements. Due to the high cost, these tests are typically only carried out for a limited number of wells in the exploration phase. In contrast, drill cuttings are available for all the wells, and thus can provide reservoir data throughout all the phases of the field development. A nuclear magnetic resonance (NMR-) based method was developed to accurately determine petrophysical properties including porosity, bulk density, and matrix density from drill cuttings of unconventional tight reservoirs. NMR technology allows for the separation of liquid signals from within and between the shale cutting particles and in combination with Archimedes-based mass measurements provides accurate porosity and density data for both vertical and horizontal wells. The results from the NMR cutting analysis were in good agreement with other accepted lab measurement techniques and the reproducibility is well within 5%. We show the measured porosity and density from the cuttings change significantly along a tested horizontal well, which is a strong indication of horizontal heterogeneity of the reservoir. The results may be used to guide selection of certain stages for hydraulic fracturing. The method can be easily adapted at wellsite to evaluate reservoir heterogeneity and select zones with large porosity for optimized fracturing. Obtaining accurate petrophysical data from drill cuttings can provide quasi-real-time data for quick formation assessment for the wellsite engineers and cut cost by reducing or eliminating some expensive and inadequate formation evaluation tools.

Petrophysical Evaluation of Thinly Laminated Depositional Sequences Using Statistical-Matching Procedures

David Gonzalez and Carlos Torres-Verdín, The University at Austin

Conventional petrophysical evaluation techniques are unable to assess individual bed properties in laminated sedimentary sequences with beds thinner than the vertical resolution of conventional logging tools. As a result of this limitation, well logs average the formation properties across an interbedded sedimentary sequence. Furthermore, in heterolithic clastic sequences, the electrical conductivity of shale dominates the response of conventional resistivity logs, leading to uncertainties in the detection of thin-bed pay zones, underestimation of hydrocarbon pore volume, and deficient calculation of anisotropic permeability.

Solutions commonly used to address this problem are primarily limited to volumetric techniques, such as Thomas-Stieber, which require subjective interpretation of volumetric concentration of shale and total shale porosity. Likewise, it is typically assumed that both sandstone and shale properties remain constant within the laminated sequence, which is not the always the case in heterolithic bedding or in laminated sequences with strong diagenetic alterations.

To address this challenge, we developed an interpretation method that reproduces the measurements via analogs of thinly laminated reservoirs. Layer-by-layer compositional and petrophysical properties are populated into the laminae using random sampling around the mean values of matrix and shale porosities, water saturation, shale volume, and matrix and shale composition. We define bed boundaries from high-resolution borehole images to increase the accuracy of the earth model, and use fast numerical simulation techniques to reproduce nuclear and resistivity logs measured across the laminated sequence. More importantly, rather than attempting to reproduce depth-by-depth the available well logs, we aim to obtain numerically simulated logs with the same statistical distribution properties as the measured logs along predefined depth intervals. Accordingly, we iteratively improve the sampling of layer properties until the mean and standard deviation of the simulated and measured logs are in good agreement.

When available, measurements, such as nuclear magnetic resonance, triaxial induction resistivity, and X-ray diffraction, provide additional information to constrain the random sampling of layer properties. We integrate these measurements with conventional well logs to detect the presence of laminations, ascertain presence of hydrocarbons, estimate water saturation, and define matrix and shale compositional properties.

Results obtained with our statistics-based interpretation method accurately reproduce the variability of well logs acquired across selected depth intervals in several field examples of heterolithic turbidite and deltaic sedimentary sequences. Furthermore, the method is successfully validated by predicting permeability based on the earth-model-derived properties and comparing it to core measurements. Finally, net-to gross and hydrocarbon pore volume are estimated using the calculated statistical properties. Our method also quantifies the uncertainty of the petrophysical calculations and allows the interpreter to assess whether shale and sandstone matrix properties can be assumed constant within a laminated clastic sequence.

Compared to conventional interpretation procedures, the formation evaluation method developed in this paper enables the incorporation of nonconstant matrix and shale properties in the laminated sequence, thereby reducing subjectivity in the interpretation of static and dynamic petrophysical properties of heterolithic clastic sedimentary sequences.

Pore-Size-Dependent Fluid Substitution Method for Improved Estimation of NMR Porosity, Permeability, and Relaxation Times

David Medellin, Ali Eghbali, You Wang and Carlos Torres- Verdín, The University of Texas at Austin

Nuclear magnetic resonance (NMR) T_2 distributions are commonly used to estimate porosity, pore-size distributions, and permeability in fully water-saturated rocks. Reservoir rocks, however, are not always found in fully water-saturated states. NMR T_2 distributions acquired with downhole tools or laboratory measurements in the presence of hydrocarbon or drilling-mud filtrate, e.g. oil-based mud (OBM), can exhibit additional and/or shifted peaks when compared to T_2 distribution of rocks 100% saturated with water. The additional peaks correspond to bulk relaxation times of oil; T_2 distribution shifts are due to thin water films in partially hydrocarbon saturated or OBM filtrate invading rocks. The extra and shifted T_2 peaks can not only impact total porosity due to differences in hydrogen index, but can severely affect permeability estimation as well as interpretation of bound and free-water volumes.

We implement a pore-size-dependent fluid substitution (PSDFS) method to remove the non-wetting phase contribution of the partially hydrocarbon saturated or OBM-filtrate invaded rocks from the acquired T_2 distribution and transform it to a fully water-saturated T_2 distribution. The method is valid in the fast diffusion regime and uses a step-function saturation profile that depends on the pore's T_2 relaxation time value, which for fully water-saturated rocks is a monotonically increasing function of pore size. Necessary inputs to the PSDFS method are a T_2-cutoff value and irreducible water saturation level for the step-function saturation profile, and the nonwetting-phase NMR parameters, namely, its T_2 decay time, hydrogen index, and total fluid volume present in the partially saturated or invaded rock.

The PSDFS method has been previously applied to sandstone samples with different oil saturations. In so doing, the T_2-cutoff value and irreducible water saturation parameters are estimated from other well logs or determined from joint inversion of T_2 distributions at depths intervals with different oil saturation values. The resultant T_2-cutoff value and irreducible water parameters can be used at other depths with similar rock types to produce fluid substituted, fully water-saturated T_2 distributions. Currently, the PSDFS method is limited to completely water-wet rocks with negligible internal field gradients and with simple pore structures, such as those of sandstone.

In this study, we apply the PSDFS method to NMR logs acquired across clastic formations. We present a workflow to estimate the necessary NMR parameters for the PSDFS method and show how to correct the measurements for mud-filtrate invasion and partial oil saturation to obtain the T_2 distribution of a corresponding fully water-saturated reservoir rock. The corrected NMR porosity, logarithmic mean, bound- and free-water partial porosities are then used to derive a corrected NMR permeability, which is compared to core-plug measurements. We found that the PSDFS method successfully improves the accuracy of permeability prediction compared to conventional interpretation procedures.

Reconciling the Modeled Log- and Core-Based Saturation-Height Functions: A Case Study From the Bayu Undan Gas-Condensate Reservoir

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Petrophysicists are adept at calculating water saturation using log data. Likewise, they are good at interpreting the core-measured capillary pressure data. In reservoir characterization, quite often, petrophysicists are required to transform the log-derived water saturation or core-based capillary pressure information into saturation-height functions for a realistic representation of water saturation in 3D geomodels and simulation models.

If, for example, a field has only log data available the solution is straightforward, generate saturation-height functions using log-derived water saturation. The situation gets complicated if the field has both log data and core-based capillary pressure measurements. The dilemma is to decide as to which data to use. As consultants, we come across varied datasets in both clastics and carbonate reservoirs all over the world. There are both commonalities and differentiators in these datasets to model water saturation. The solution to each problem could potentially be different. In our experience, very often, there is no unique solution and the saturation-height functions can be generated using log data entirely or using core data alone or combining both datasets.

In other words, the outcome is reservoir and data specific, as will be shown with an example from a case study from the Bayu Undan gas condensate field at the Bonaparte Basin of Northwest shelf of Australia. It will be demonstrated in this study that when both datasets are available, reconciling them to arrive at a realistic saturation-height model is the key. The intent is to emphasize that there is no universal preference. It is left to the discretion of the petrophysicists as to which path to take in order to generate the saturation-height functions as realistically as possible honoring the available data and interpretations.

Reservoir Fluid Geodynamics in Brazilian Presalt Carbonate Field

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The objective of this study is to characterize fluid distributions in a presalt field by using well data including downhole fluid analysis (DFA) from wireline formation tester (WFT), openhole logs, and a simplified structural/geological model of the field. From an understanding of the petroleum system context of the field, reservoir fluid geodynamics (RFG) scenarios are developed to link the observations in the existing datasets and suggest opportunities to optimize the field development plan (FDP). An understanding of connectivity is developed based on asphaltene gradients. The asphaltene gradients exhibit a bimodal distribution corresponding to two the light-oil model and black-oil model of aspshaltenes.

DFA measurements of optical density (OD), fluorescence, inferred quantities of CO_2 content, hydrocarbon composition and gas/oil ratio, of fluids sampled at discrete depth in six presalt wells are at the basis of this study. DFA data at varying depth captures fluid gradients for thermodynamic analysis of the reservoir fluids. OD linearly correlates with reservoir fluid asphaltene content. Gas-liquid equilibria are modeled with the Peng-Robinson equation of state (EOS) and solution-asphaltene equilibria with the Flory-Huggins- Zuo EOS based on the Yen-Mullins asphaltenes model. OD and other DFA measurements link the distribution of the gas, liquid and solid fraction of hydrocarbon in the reservoir with reservoir architecture, hydrocarbon charging history, and postcharge RFG processes.

Asphaltene gradient modeling with DFA reduces uncertainty in reservoir connectivity. The CO_2 content in some section of the field fluids limits the solubility of asphaltene in the oil, and over very large intervals, the small asphaltene fraction exists in a molecular dispersion state according to the Yen-Mullins model. This is the largest vertical interval yet published of such a gradient (300 meters gross pay) providing a stringent test of the corresponding model. This gradient of asphaltene molecules (light-oil model) is compared with recent molecular imaging of asphaltene molecules showing excellent consistency. In addition, in limited intervals, larger asphaltene gradients are measured by DFA and shown to be consistent nanoaggregates (the black-oil model). This bimodal behavior is compared with laboratory measurements of nanoaggregates of asphaltene molecules again showing consistency. This case study reinforces the applicability of the FHZ EoS in treatment of reservoir asphaltene gradients. The CO_2 concentration was modeled with the modified Peng-Robinson EOS in good agreement with measurements in upper reservoir zones. Matching pressure regimes and asphaltene gradients in Wells B and C indicates lateral connectivity.

The hydrocarbon column in this part of the reservoir in thermodynamic equilibrium. In Wells A, C, D, E and F the OD of the oil indicate an asphaltene content increase by a factor of four at the base of the reservoir as compared to the crest of the reservoir. This tripled the viscosity in Wells C and D as indicated by in-situ viscosity measurements. The accumulation of asphaltenes at the bottom of the reservoir is most likely driven by a change in solubility due to thermogenic CO_2 diffusion into the oil column from the top down.

The challenge of the limited number of wells in the development phase of a presalt field for obtaining data to evaluate reservoir connectivity before the FDP is ably addressed by deploying the latest WFT technologies, including probes for efficient filtrate cleanup and measurement of fluid properties. These measurements and methodology using a dissolved asphaltene EOS enabled developing insightful RFG scenarios.

Temperature-Correction Model for NMR Relaxation-Time Distribution in Carbonate Rocks

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For most resource formation evaluation applications, NMR-based interpretation models were developed and calibrated with laboratory core analysis conducted at ambient conditions. In the public domain, few studies have been published to investigate the relationships between experimental temperature and NMR relaxation-time distributions. The main objectives of this study are to study temperature effects and establish methods for correcting temperature effects on NMR relaxation-time distribution measurements.

In this experimental study of carbonate rocks, including outcrop and reservoir carbonates, laboratory NMR tests were conducted at four different temperatures ranging from ambient, at 75°F, to a nominal reservoir temperature at 200°F. Data from rock properties were generated in the laboratory by NMR and other core analysis techniques. With the data generated, a systematic data-analysis approach was used to build models for correcting temperature effects on NMR relaxation time in terms of T_2cutoff and T_2GM. The systematic data analysis approach consists of three main steps: selecting core samples efficiently to cover various qualities of carbonate reservoirs; characterizing and transforming NMR T_2 distributions into robust features; and building more accurate models with hybrid data-analysis methods.

The developed NMR temperature-correction model was implemented for in-situ NMR log pore typing. With this approach, the laboratory measurement-based T_2cutoff and interpretation model parameters (such as Coats permeability) can be adjusted and used directly for log interpretation without additional corrections to NMR T_2 distributions.

Still, carbonate rocks are known to be complex with highly heterogeneous pore systems. It is common that primary and secondary pores coexist. Thus, the overall temperature dependence of the T_1 and T_2 distributions are likely governed by multiple underlying mechanisms; thus, the dependency may not be accurately represented by a reduced number of characteristic parameters, such as T_2GM.

Hence, for a more accurate derivation of petrophysical parameters from NMR logs, this paper also attempts to describe the temperature dependence by considering the NMR relaxation time distribution in its entirety. Due to the high-dimensional data structures of NMR distributions, it will be very challenging, if not possible, to develop a temperature-dependence model for the NMR distributions with the conventional data-analysis approaches with linea or semilinear models. It is further compounded by two very common issues for data analysis and model development (i.e., limited data and uncertain data quality and representativeness). With the systematic data analysis approach, this study discusses an NMR T_2 distribution temperature-correction model and its application to in-situ NMR log data for pore typing. To our knowledge, this is the first systematic attempt in the industry to develop an NMR temperature-correction model for in-situ carbonate NMR pore typing.

The Final Piece of the Puzzle: 3D Inversion of Ultradeep Azimuthal Resistivity LWD Data

Nigel Clegg, Timothy Parker and Bronwyn Djefel, Halliburton; David Marchant, Computational Geosciences Inc.

Improved well placement requires three-dimensional (3D) spatial knowledge of the reservoir formation and fluids. Current one-dimensional (1D) inversions of ultradeep azimuthal resistivity logging-while-drilling (LWD) data recover formation boundaries above and below the wellbore, which are stitched together to form pseudo-2D models (or “curtain plots”) along the wellbore. However, 1D modeling, by definition, does not account for any lateral variations due to changes in formation dip, lithology, or fluids, such that any actual D or 3-D variations manifest ambiguously within artifacts or distortions in the pseudo-2D models. These lateral variations can have a significant impact on both well placement and subsequent production-related decisions (e.g., where a change in well azimuth could be more beneficial than a change in inclination during drilling). An accurate and computationally efficient full 3D inversion of ultradeep azimuthal resistivity LWD data, capable of capturing arbitrary and multiscale reservoir complexity, would yield 3D earth models that could provide as-yet unrealized insight for reservoir characterization and well placement.

This paper presents the industry's first such 3D inversions of ultradeep azimuthal resistivity LWD data. The case study presents a complex reservoir with significant subseismic faulting and a long history of water injection, resulting in significant temporospatial fluid substitution within the reservoir formations. The complexities in this reservoir make it both an ideal candidate and a difficult, yet critical, first test to prove the value of 3D inversion. In a well where major faults were predicted to cross the well path at an oblique angle and injection water was predicted from 4D seismic data, the resistivity boundaries as recovered from 1D inversions alone did not adequately explain the reservoir state. Analysis of density-image dips confirmed that the well path crossed faults at an oblique angle and that the faults were also tilted in the vertical plane. Several of these faults acted as a barrier to the migration of fluids and showed a sharp resistivity boundary from oil to water. This allowed mapping of the faults distant from the well path using ultradeep resistivity LWD data. Incorporating the information from these tools with the 4D seismic data enabled validation of the 3D inversion.

The 1D inversion yielded valuable information to assist in well placement, but the 3D inversion provided significantly more insights, which will realize step changes in reservoir characterization and future well-placement operations. It is very clear from the 3D inversion that a tilted oil/water contact at the start of the well is observed to change in the horizontal plane, as well as the vertical plane, such that an azimuthal adjustment of the well path would have resulted in significantly more net-to-gross. Faults separating zones of water invasion identified as being crossed by the well at an oblique angle are clearly defined, presenting the position of the oil/water contact a significant distance to the sides of the wellbore, which is vital information when considering how to complete the well and forecasting future production.

The Impact of Petrophysical Uncertainty in Formation Evaluation and Reservoir Modelling—A Robust Methodology

Michele Arcangeli, Niccolò Ceresa, Maria Teresa Galli, Paola Cardola and Paolo Scaglioni, ENI

The assessment of geological uncertainties in reservoir characterization and risk analysis is nowadays a common and standard approach, but it is not yet available as a unique, robust methodology for the evaluation of the uncertainty from well measurements down to the risk-analysis process. Developing a sound methodology for the correct evaluation and propagation of petrophysical uncertainty is therefore mandatory.

This work wants to introduce a novel approach for the correct evaluation and propagation of petrophysical uncertainty. The workflow was applied to a deepwater, gas-bearing sandstone reservoir, with a complete and continuous set of log data in all wells and several cores in the reservoir interval.

The scope of our work included three main steps:

1. Analysis of the uncertainty in input data, including well logs and core analyses.
2. Definition of a workflow aimed at achieving a ready-to-use approach for the evaluation of the uncertainty associated to the main petrophysical properties, like porosity, permeability and water saturation.
3. Propagation of the petrophysical uncertainty to reservoir static model and risk analysis through fit-for-purpose approaches, defined by a multidisciplinary team including sedimentologists, petrophysicists, geologists and reservoir engineers.

The improved knowledge of the uncertainty in the petrophysical properties allowed the definition of various scenarios, from conservative to optimistic, highlighting possible zones of further development; in particular, a sounder knowledge of the uncertainty associated to permeability contributed to a more robust evaluation of GIIP.

In critical intervals, not covered by core data but characterized by facies analysis, the approach provided significant insight in the representativeness of core data and allowed to better understand the role played by log quality.

The analysis of the results, in shape of statistical distribution of porosity, permeability and N/G, proved that the developed approach is robust and methodologically correct.

Overall, the availability of a quantitative and robust estimate of the petrophysical uncertainty proved beneficial to the construction of a final reservoir model honoring both static and dynamic measurements.

The Sensitivity of Dielectric Signals to Cation Exchange Capacity in Shaly Sand Formations and its Dependence on Salinity, Porosity, and Tortuosity

Chang-Yu Hou, Denise E. Freed and Jeffrey Little, Schlumberger

Saturation interpretations of shaly sand formations from conventional resistivity logs are known to be affected by the presence of clay minerals. As a result, saturation models that account for clay will require the value of the formation cation exchange capacity (CEC), which is obtained from core measurement or inferred indirectly from the lithological interpretation. Multifrequency dielectric logging signals are sensitive to the CEC of the formation, and enable acquiring continuous logs of the CEC, water-filled porosity, water salinity, and a texture exponent associated with the water phase tortuosity (similar to the Archie *m* cementation parameter in the case of fully water-saturated rocks). Even though dielectric tools measure the electromagnetic response only in the flushed zone, the resulting CEC and texture parameters are often used as inputs to the saturation interpretation in the virgin zone. With this broader implication and application in mind, it is prudent to understand the conditions in which dielectric measurements and their interpretation can reliably provide these petrophysical parameters. In addition, because the clay effect is, for simplicity, often ignored in dielectric interpretations, particularly in formations with a high brine salinity, it is even more crucial for the accuracy of petrophysical interpretations to determine whether the clay effect can be neglected in a given environment. Hence, the goal of this study is to address and shed light on when the CEC affects the dielectric response and when it can be reliably obtained from dielectric logs.

Our study is based on the recently established dielectric shaly sand model by performing a self-consistent sensitivity study to determine how reliably the CEC can be obtained from dielectric measurements. Together with analytic arguments, we found that the sensitivity of the dielectric signals to the CEC depends on both the formation factor and the brine salinity of the formation. As a result, the minimum value of formation CEC, in units of meq/100 g, that can be reliably inverted for is identified for different values of these two parameters. For practical use, a simple criterion, which involves comparing the formation conductivity and CEC value, was derived to provide guidance on whether the dielectric measurement is sensitive to the formation CEC. In contrast to common belief, the dielectric interpretation can be substantially affected by the presence of clay in the high brine-salinity region, even though it loses sensitivity to the variation of salinity and porosity in such cases. Finally, we applied the derived criterion to log data and demonstrate how our findings help to identify regions where properly accounting for the clay effect becomes essential.

Towards a Petrophysically Consistent Implementation of Archie's Equation for Heterogeneous Carbonate Rocks

Raghu Ramamoorthy, Independent; Suvodip Dasgupta and Ishan Raina, Schlumberger

Archie's equation, introduced in 1942, has stood the test of time in the petroleum industry. While Archie himself recommended against the use of his equation to estimate saturation in carbonate rocks, over three-quarters of a century later, Archie's equation is still nearly universally used to derive water saturation in carbonate formations by adjusting the parameters of the equation—cementation and saturation exponents—based on evidence from core data. Industry literature is replete with examples why this approach leads to erroneous estimates of the water saturation. However, the method survives due to its simplicity and ease of use. Several researchers have attempted to develop better transforms to model electrical conduction in heterogenous carbonate rocks. These are less accepted mainly due to difficulties in implementation and in determining the various parameters required for the equation.

Carbonate rocks exhibit complex pore geometries and may be conceptualized as a spatial juxtaposition of different pore systems, each with its own capillary pressure behavior. Hence, water saturation is not uniformly distributed in the rock. Herein lies a fundamental criticism of the Archie equation, which recognizes only one saturation and one type of pore for the entire rock. Furthermore, when hydrocarbon initially migrates into the water-wet rock, it will enter through the larger pore throats first. Smaller pore throats will not be breached until all the larger throats have first been entered by the hydrocarbon. Hence, principles of petrophysics determine the sequence of desaturation of the pore system. Petricola et al. first proposed a sequential method of applying the Archie equation. The rock is partitioned into three pore systems—microporous, mesoporous and macroporous. The method for estimating saturation recognizes the sequence of oil entry and water flood of the pore systems consistent with the known wettability states of the rock. We propose a solution that is similar to the Petricola model though the conductivity mixing laws are based on that proposed initially by Ramakrishnan et al. While the principal input to the pore partitioning is based on nuclear magnetic resonance (NMR) data, we also recommend alternate approaches that may be applied in the absence of NMR data.

The method is demonstrated for the case of an initial water-wet carbonate formation that has been subject to oil migration and subsequent wettability alteration. We also consider the case when such a formation is subject to invasion by a water-based mud filtrate. With a view to keeping the method simple and objective, we provide detailed guidance for the selection of the parameters of the transform. The approach attempts to retain the simplicity of the Archie equation while simultaneously honoring the petrophysical principles governing the ingress and extraction of hydrocarbon in heterogenous carbonate formations.

Unravelling the Understanding of a Complex Carbonate Reservoir With the Use of Advanced Logs Integration

Harish B. Datir and Karl-Erik Holm Sylta, Schlumberger Norway AS; Ingrid Piene Gianotten and Terje Kollien, Lundin Norway AS

The Alta discovery was proven in carbonate rocks with high formation water salinity from the Permian age, which has gone through extensive leakage processes, where ~200 m of water rise has been witnessed. This poses intrinsic challenges and complexities with regards to imbibition, uncertainty around the current free-water level and presence of fluid pseudocontacts within the field. Considering the impact of the imbibition process on saturations and later to the estimation of reliable drainage curve from the capillary pressure, imposes a huge uncertainty on the hydrocarbon volume estimation. The petrophysical methods described herein accurately describe and quantify the formation fluid volumes, which are essential for the understanding of the fluid distribution across the field.

The work described in this paper addresses the risk associated with the evaluation of heterogeneous complex carbonate reservoirs as mentioned above, and provides integrated new solutions. In contrast to conventional reservoirs, where the presence of clay is the key challenge for obtaining a reliable saturation, the largest uncertainty factors in the reservoirs described here is the complex tortuosity (Archie's m and n) and the pore-size distribution, which varies significantly across the field. Hence, conventional resistivity-based water-saturation (S_w) equation failed to comprehend the heterogeneity present in this carbonate reservoir unless guided by core data over the entire reservoir interval. During initial evaluation it was absent and not available over the entire reservoir interval, leading to unreliable water saturations To overcome the heterogeneity challenges, integration of advanced petrophysical logs, such dielectric and elemental spectroscopy, were used while NMR bound-fluid data was analyzed with respect to deep- versus shallow-zone water saturation to anticipate the fluid movability in the near-wellbore region and thereby improving the understanding of the present-day free-water level in each well. The paper also shows an alternative method of estimating S_w from the sigma log, an output from new-generation spectroscopy. This serves as an additional validation to the estimated water saturation in a heterogeneous complex mineralogy formation.

The petrophysical interpretation of saturation using Archie was quality controlled/cross-checked with a saturation estimation based on sigma, calibrated with the use of advanced measurements. This in combination with early indication of mobile versus immobile hydrocarbon and the initial depth estimate of free-water level improved the confidence of a more accurate capillary pressure drainage curve. This resulted in a good understanding of the imbibition process which drives the present water saturation. The results generated with this integrated analysis were the key inputs for obtaining initial hydrocarbon volumes. It was of critical importance to know the initial estimates of hydrocarbon volume and its drainage strategy for making the decision of commercially developing this field.

Wavelength-Based Axial-Resolution Limitations of Flexural-Wave-Dispersion Sonic Logging

Kristoffer Walker, Ruijia Wang and Qingtao Sun, Halliburton

Dipole sonic logging can estimate formation shear velocity in all formations, and thus has important applications in lithology classification, porosity estimation, geomechanical modeling, and pore-pressure prediction. Conventional methods use a dipole source to excite the flexural-wave mode. This guided wave travels along the borehole wall with a phase velocity that is dispersive. The low-frequency asymptote of this dispersion indicates the formation shear velocity, which is usually measured with a time- or frequency-domain beamforming method. Modern-day borehole acoustic tools have an array of receivers spanning an axial aperture of 6 feet, which permits one to use a subarray of receivers to sense a shorter axial length of investigation. Because smaller apertures usually increase the sharpness of a dipole sonic log's appearance, one often assumes the aperture length dictates the true axial resolution. That would be a natural extension of ray theory, but flexural-wave propagation is not governed by ray theory. The Fresnel zone is a well-known, wave-based propagation concept that describes the radial extent of the sensing region along the source/receiver ray path. As frequency decreases, wavelength increases, and the radial sensing region expands.

This paper shows that there is an instantaneous axial extent of sensing that controls the true axial resolution of flexural-wave phase velocity. Specifically shown, are the results of applying frequency semblance to flexural-mode waveforms created by 3D finite-difference time-domain simulations where the thickness and velocity contrast of interbedding are precisely controlled. Variations in phase velocity are attributed to the influences of adjacent beds outside the aperture of the array. Assuming a vertical borehole in a horizontally layered medium, as frequency decreases, wavelength increases and flexural asymptotes associated with these adjacent beds exists at low frequencies. Where the wavelength equals the bed thickness at a higher frequency, a second asymptote associated with the shear velocity of the thin bed exists and persists up to a frequency where the dispersion begins. An aperture cutoff point exists as aperture reduces where other factors in the mode excitation do not permit the development of a high-frequency asymptote. For example, a 2-ft bed with a 15% velocity contrast for an 8.5-in. borehole predicts an asymptote that is not observed in the frequency range near the group velocity minimum. However, the same formation with a smaller borehole radius would shift the group velocity minimum to higher frequencies, permitting the 2-ft bed asymptote to be visible. These relationships exist for both fast and slow formations. This work also demonstrates that these findings can be observed in actual log data. One practical conclusion of these results is that the monopole refracted-shear logs are more capable of higher axial resolution, providing the formation is fast enough that the refracted shear is well separated from the Stoneley mode.

Wettability Assessment in Complex Formations Using NMR Measurements: Workflow Development and Experimental Verification in Rocks With Multimodal Pore-Size Distribution

Chelsea Newgord, Saurabh Tandon and Zoya Heidari, The University of Texas at Austin

Nuclear magnetic resonance (NMR) measurements are typically used for estimating fluid saturation, pore structure, and wettability. However, interpretation of NMR measurements can be challenging in rocks with both complex pore structures and unknown wettability due to multiple peaks in the transverse (T_2) responses. Reliability of the conventional NMR-based wettability models has been verified for rocks with unimodal pore-size distributions. They also require challenging calibration efforts. This limits the application of the existing NMR-based models for wettability assessment, especially for complex carbonates with multimodal pore-size distribution. The objectives of this paper are (1) to develop a new workflow that uses NMR measurements to simultaneously estimate fluid saturation and wettability and (2) to verify the reliability of the new workflow in rocks with multimodal pore-size distribution at different levels of fluid saturation.

In this paper, we introduce a new model and workflow to estimate wettability and fluid saturation using NMR measurements. The new model requires T_2 and diffusivity-T_2 (D-T_2) NMR measurements of the rock-fluid system, saturating fluids, fully water-saturated water-wet, and fully oil-saturated oil-wet rocks. The outputs of this workflow are fluid saturation and wettability. To experimentally verify the reliability of the introduced workflow, we chemically alter the wettability of the core samples to be water-wet, mixed-wet, or oil-wet. We confirm and quantify the wettability level in each core sample using the Amott Index and contact angle measurements. Using a low-frequency 2-MHz NMR spectrometer, we measure the T_2 and D-T_2 responses of the rock-fluid system and the aforementioned model inputs. We vary the fluid saturation using a coreflood setup and obtain NMR measurements at different fluid saturations. Finally, we input the NMR measurements to the new workflow to simultaneously estimate fluid saturation and wettability.

We successfully applied the new NMR-based workflow to different types of carbonate rocks with multimodal pore-size distribution. NMR measurements and MICP measurements confirmed that these rock types had multimodal pore-size distributions. The reliability of the new workflow was verified by comparing the fluid saturation estimates with the gravimetric measurements, and the

NMR-based wettability estimates with the Amott Iindex and contact-angle measurements. As the nonwetting fluid was injected into the core samples, the T_2 distribution varied nonlinearly due to the combined impacts of wettability and complex pore structure. The calculated NMR-based wettability index ranged from −0.7 to 0.5 for all the core samples, while the Amott index ranged from −0.6 to 0.5 indicating oil-wet to water-wet samples. The NMR-based wettability index was consistent with contact-angle measurements and had an average relative error of 35% when compared to the Amott index. This new workflow expands NMR-based wettability assessment to rocks with multimodal pore-size distribution, such as complex carbonates. Additionally, the introduced NMR-based wettability assessment workflow can be expanded from the core-scale domain to depth-by-depth in-situ reservoir characterization using borehole NMR measurements, if the model input parameters are reliably assessed, as documented in this paper.

FORMATION EVALUATION OF UNCONVENTIONAL RESERVOIRS

Crushed-Rock Analysis Workflow Based on Advanced Fluid-Characterization Techniques for Improved Interpretation of Acquired Core Data

Melanie Durand, Anton Nikitin, Adam McMullen, Aidan Blount, Amie Hows and Brian Driskill, Shell

As activity increases in the Permian Basin and multiple billion-dollar acquisitions upwards of $50,000/acre continue, there is a strong incentive for E&P operators to optimize the development in their existing acreage. Unfortunately, maximizing oil production typically results in significant amounts of produced water. Water cuts for individual Permian wells commonly range from 50 to 90% of total liquid production, thus, the ability to predict water/oil ratio (WOR) of the produced fluids has a major importance for development planning.

Petrophysicists are often entrusted with estimating WOR based on saturation modeling. Core data acquisition and analysis are critical for developing a quantitative petrophysical model. However, accurately measuring saturations of cores taken from unconventional reservoirs continues to pose significant challenges originating from uncertainties in the acquired data and assumptions used to interpret these data.

For example, the crushing of the core samples, which is required for efficient fluid extraction in tight rocks, causes systematic fluid losses which are not typically quantified. Instead, all as-received air-filled porosity is commonly assumed to represent hydrocarbons that have escaped during coring due to gas expansion. Additionally, fluid extraction from commercially available retorting systems can have widely variable fluid collection efficiency (<100%) resulting in significant inconsistencies between the weight of the collected fluids and sample weight loss during retorting experiments. The Dean-Stark technique removes not only fluids (water and oil) but an unknown volume of the extractable organic matter, and it only allows for direct quantification of the volume of extracted water. The reconciliation of fluid volume and fluid- and sample-weight data delivered by either of the two techniques (i.e., retorting or Dean-Stark) require numerous assumptions about properties of pore fluids which are typically not verified through direct measurements. Such assumptions can lead to up to 50% uncertainty in water saturation.

To address such critical uncertainties, a novel core analysis workflow using improved core-characterization and fluid-extraction techniques was developed. To address fluid loss during crushing, this workflow employs advanced NMR measurements performed on both as-received and crushed samples to quantify fluid losses. Also, this approach uses retorting techniques with close to 100% fluid collection efficiency specially developed for core-sample characterization. In addition to these advances in measurement technologies, the workflow is optimized to avoid fluid losses during sample handling and includes repeated grain-density and geochemical measurements at different stages. As a result, the new workflow reduces the uncertainties in acquired data and better informs the assumptions for interpreting the measured data into the desired petrophysical properties (e.g. total porosity, water saturation). The workflow is demonstrated for a set of Wolfcamp samples.

Determining Resistivity and Dielectric Constant Simultaneously Using Induction Data in the Presence of Strong Induced Polarization

Gong Li Wang, Dean M. Homan, Natalie Uschner, Ping Zhang and Wael Abdallah, Schlumberger

Laboratory and field data have shown that sedimentary formations can exhibit a fair amount of induced polarization (IP) effect in the presence of clay, pyrite, or graphitic carbon. The effect can be so strong that the quadrature signal of induction data can be pulled towards the negative direction in an appreciable manner, causing an adverse effect in the standard data processing and interpretation of induction data. On the other hand, the strong IP effect makes it possible to determine the dielectric constant at induction frequencies neglected in standard data-processing techniques.

A new processing technique has been developed that enables simultaneous determination of resistivity and dielectric constant in dipping formations using both the in-phase and quadrature signals of induction data. The resistivity log created by the new processing can be used in the same way as standard resistivity. The dielectric-constant log, a new deliverable from induction data, provides a new perspective into reservoirs. It introduces an opportunity for new petrophysical applications, for example, approximating a continuous maturity index of kerogen in unconventional reservoirs, and estimating cation exchange capacity (CEC) of shaly sand formations.

The new technique is a combination of the maximum entropy and the Occam inversions, which makes the iterative process converge rapidly over a wide range of initial-guess models for resistivity and dielectric constant. The new processing considers layering and dipping of formation systematically by means of a planarly layered model that can dip at a relative dip angle of up to 75°. With this approach, the obtained resistivity and dielectric logs are free of both layering and dip effects, which often appear in the form of polarization horns or overshoots at large relative dip on standard logs.

Using the quadrature signal overcomes the ambiguity of resistivity estimation caused by the strong skin effect in conductive formations. This allows for the unique determination of resistivity and dielectric constant over a broad range of formation resistivities with only single-array data. The nonuniqueness cannot be achieved without joint use of both short- and long-spacing arrays for the standard processing. In addition, the large depth of investigation of the quadrature signal makes the inverted resistivity and dielectric constant more representative of the undisturbed zone than the resistivity obtained using only the in-phase signal.

The new processing technique has been applied to more than 20 wells containing induction logs. Results suggest that the strong IP effect is present in many well-known formations where the dielectric constant ranges from thousands to hundreds of thousands. Results also confirm the superiority of resistivity obtained with the new processing over that of the standard processing technique in a variety of situations. The new processing results of several field cases are analyzed in conjunction with elemental spectroscopy data to shed light on the correlation between large dielectric constant and clay, pyrite and graphitic carbon.

Dielectric Relaxation-Time Distributions From Broadband (40 Hz to 110 MHz) Frequency-Domain Measurements of Partially Saturated Shales

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The complex broadband (Hz to GHz) dielectric response of 'moist' rocks arises from a range of polarization processes related to individual molecules, electrochemical potentials and interfacial charge accumulation. Several authors have highlighted the potential of using electrical relaxation times to extract important hydraulic properties like permeability, textural properties of pore surfaces and pore-throat sizes. However, despite the many experimental studies and theoretical works, clear experimental evidence and a complete model for broadband dielectric behavior in moist rocks is still yet to be realized.

Here, for the first time, we demonstrate the application of Tikohonov regularization methods to compute distributions of relaxation times directly from broadband (40 Hz to 110 MHz) frequency-domain dielectric measurements of shale rocks. We relate the observed relaxation times to polarization mechanisms that occur over the frequency range measured. The evolution of relaxation times with increasing water content is studied, with the dielectric response of shales measured at six saturation states ranging from dry to pressure saturated. Furthermore, we demonstrate how the impact of conduction currents can be quantified via the Kramers-Kronig relation from the regularized relaxation-time distributions. Lastly, we compare the evolution in polarization mechanism with water content to the cation exchange capacity and porosity of the shale samples; the implications for shale characterization from dielectric relaxation times are discussed.

Feasibility of Digital Rock Physics for Static and Dynamic Reservoir Property Characterization in Carbonate Reservoirs-I

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Access to subsurface cores for running multiple experiments is gradually becoming a rarity, chiefly for two reasons; it is hard on time and money. Additionally, the alternative provided by the digital methods is becoming increasingly popular, not only for the improved economics but also for the repeatability of results and the flexibility in modeling multiple scenarios on the same image volume. Digital rock physics (DRP) is one such method that offers to model the static and dynamic reservoir properties with better control on subjective biases of the experimentation and is also nondestructive in nature. DRP involves imaging the formation and simulating the field performance to account for various hetrogeneities in the reservoir formation. DRP has proved to be highly successful in clastic reservoirs but in cases of complex reservoirs, such as carbonates and unconventional resources, however, it is still at the feasibility stage. The reasons are plenty ranging from method of imaging, availability of calibration libraries, transition space error, and its quantification.

In this paper, we looked at several carbonate sample images—exhibiting a range of heterogeneity—to understand the detectability of total pore volume and the pore types present in the formation. This work has a two-fold objective (1) to estimate the impact of heterogeneity on successful determination of the pore volume in carbonate rocks, and (2) to segregate the pores into their types by size (micro, meso, and macro) and by aspect ratio (AR). Whereas as the size of pores controls the schemes of fluid flow in formations, their aspect ratio controls the elastic property behavior in stressed rocks. Because the processes are coupled, it becomes all the more important to calibrate DRP modeling results with laboratory measurements for a greater understanding and for creating rock physics forward models that combine these processes. In this work, we explain the approach of testing and filtering to reach a successful segmentation algorithm, its comparison with the laboratory measurements and also its limitations. We will also discuss the effect of wettability on fluid flow, especially in the scenario where oil gets trapped in the pores in the case of a water-wet reservoir.

High-Resolution Mineralogy Modeling—A Case Study in the Vaca Muerta Formation, Neuquén Basin, Argentina

Hao Zhang, Nora Alarcon and Guillermo Crespo, Baker Hughes, a GE Company; Diego Licitra, YPF; and Carlos Hernandez, Chevron LC YPF

Accurate mineralogy modeling and interpretation for thinly bedded formations often requires high-resolution data, usually measured in the laboratory from core samples. However, core measurements are expensive and available only in a limited number of wells in a field. On the other hand, high-resolution logging tools are not sufficient to provide a comprehensive mineralogy characterization. Because other types of logging data are also available from many wells, a high-resolution mineralogy analysis combining low-resolution and high-resolution logging data becomes very attractive.

This study focuses on solving for high-resolution mineralogical compositions of the formation combining pulsed-neutron spectroscopy measurements, image logs, and other conventional log responses. A workflow has been developed with the following major steps

(1) Extract lithology volumetric models from high-resolution image logs combined with other conventional logs.
(2) Allocate the modeled mineralogical compositions from lower-resolution geochemical logs into mineral compositions for various lithology types.
(3) Obtain a high-resolution mineral model.
(4) Perform a quality check by comparing the computed results with core measurements.

To demonstrate the method's feasibility and applicability, the proposed workflow was used on a Vaca Muerta log example from the Loma Campana field, which has dramatic variations in mineralogy composition. The processing showed very promising results with the computed high-resolution mineral model matching the core data. This result indicates the proposed method could reproduce the mineral composition with a full vertical variability in a thin-bedded formation that would only be available with extensive core measurements.

The approach presented here can offer an integrated, high-resolution formation evaluation for key petrophysical properties, such as formation composition, permeability, porosity, and geomechanical properties. The method provides a great advantage over conventional log interpretation by revealing the full vertical variability of a formation that would otherwise appear insensitive for thin layers with limited resolution and compromised accuracy. The promising results generated from this study demonstrate the feasibility of an integrated core-level petrophysical analysis in a cost-effective and timely manner compared to conventional core measurements.

Improved Analysis of NMR Measurements in Organic-Rich Mudrocks Through Quantifying Hydrocarbon-Kerogen Interfacial Relaxation Mechanisms as a Function of Thermal Maturity

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Nuclear magnetic resonance (NMR) measurements have become a popular choice for estimating hydrocarbon reserves in organic-rich mudrocks. NMR interpretation is, however, challenging in organic-rich mudrocks. The reasons include overlapping of clay and hydrocarbon NMR responses, and limited knowledge of kerogen-hydrocarbon interactions. Previous publications have shown that the dominant mechanism for surface relaxation in organic pores is intramolecular dipolar coupling among hydrocarbon protons. However, the influence of kerogen intermolecular interactions with hydrocarbons and its thermal maturity on surface relaxivity has not been reliably quantified using experimental measurements. This limits the ability of NMR to accurately quantify kerogen hydrogen index and its impact on kerogen absorption capacity. The objectives of this paper are to (1) experimentally quantify the influence of intermolecular coupling and kerogen thermal maturity on hydrocarbon-kerogen interactions, (2) analytically derive an expression for intermolecular surface interactions as a function of hydrogen index, and (3) compare the analytically predicted relaxivities with experimentally measured ones in kerogen-chloroform mixtures.

First, we selected three organic-rich mudrocks with different kerogen types and extracted pure kerogen from each of these formations. The extracted kerogen samples were synthetically matured by increasing temperature at 4°C/min up to 450°C under a controlled environment. The petrophysical properties of kerogen samples at different thermal maturities were quantified using pyrolysis and BET (Brunauer–Emmett–Teller) measurements. The kerogen samples were then saturated with protonated and partially-deuterated chloroform mixtures. Chloroform has one proton in its molecule and doesn't undergo intramolecular coupling. We performed transverse (T_2) and longitudinal and transverse relaxation (T_1-T_2) measurements on the kerogen samples at different thermal maturities saturated with chloroform. We used the results of T_1-T_2 and T_2 measurements to confirm the prevalence of intermolecular coupling in kerogen-fluid interactions. We combined generalized Langmuir adsorption theory with anisotropic molecular rotation to analytically derive an expression for surface relaxivity due to intermolecular kerogen-hydrocarbon interactions. We finally compared the analytical model to the surface relaxivities calculated empirically using NMR T_1-T_2 measurements.

The results demonstrated that as kerogen samples were synthetically matured from 25 to 450°C, hydrogen indices relatively decreased by up to 89% and BET surface areas increased relatively by up to 206%. The kerogen surface relaxivities relatively decreased by up to 55% as chloroform deuteration was increased from 0 to 80%. In the cases of constant chloroform deuteration, surface relaxivities relatively decreased by up to 33% as kerogen samples were synthetically matured from 150 to 450°C. The new surface relaxivity model was able to reliably quantify the trend observed in experimental measurements. Improved assessment of kerogen surface relaxivity enhanced the NMR-based hydrocarbon saturation estimates relatively by up to 35% for kerogen samples by providing temperature corrections for adsorbed phase cutoff values. The outcomes of this paper enable reliable quantification of influence of hydrogen index and thermal maturity on T_2 and T_1-T_2 measurements. Using the new surface relaxivity model, the T_2 and T_1-T_2 cutoff values derived from the laboratory-scale measurements can be extended to in-situ conditions improving downhole estimates of NMR-based hydrocarbon saturation in organic-rich mudrocks.

Integrated Petrophysical Interpretation and Workflow for Stacked Tight Gas Sands Using Modern Evaluation Techniques—A North Louisiana Multiwell Case Study

Rojelio Medina, Halliburton; Luke Fidler, Range Resources; Nick Garrison, Bhaskar Sarmah and John Quirein, Halliburton

Thin, highly interbedded sand-shale tight gas plays are generally characterized by a low resistivity response and considerable variation in pore-size distribution, and require reservoir stimulation to make them economically viable. The Upper Jurassic and Lower Cretaceous Lower Cotton Valley formation in north Louisiana/ east Texas is one such play. This stacked clastic reservoir provides significant challenges in determining the best zone to be targeted for horizontal well hydrocarbon exploitation. The presence of clay in the intergranular spaces and in the matrix of the rock affects the cementation-exponent parameter that is used to estimate water saturation. The smaller and varying pore-size distribution in these rocks affects reservoir deliverability and variation in bound vs. free fluids. Additional challenges include accurate characterization of net pay, productivity prediction, unexpected water production, and the selection of the optimal fracture stimulation strategies to use.

This paper showcases the development and application of an evaluation workflow that addresses the reservoir characterization challenges. Local experience has demonstrated that a standard triple-combo log is generally inadequate to address these problems. An advanced logging suite was deployed that consisted of a triple-combo tool, a pulsed-neutron-capture mineralogy tool, a high-frequency dielectric wireline tool, a magnetic resonance imaging tool, a dipole sonic tool, and an advanced wireline resistivity tool that can resolve horizontal and vertical resistivity simultaneously.

The developed workflow was applied to rank the horizontal well producibility potential of the stacked sands. Routine and special core analysis was used to calibrate the log-based interpretation models. The interpreted mineralogy was used to enter the matrix dielectric constant to the dielectric interpretation, which was used to provide an estimate of a variable cementation exponent confirmed by core data. The nuclear magnetic resonance (NMR) data were used to estimate clay-bound water, capillary-bound water, and pore-size-variation-based permeability. A novel feature of the horizontal, vertical resistivity interpretation was to use the clay (rather than shale) calibrated to core data to predict the sand resistivity. A 3D anisotropic rock mechanical model was developed, which takes into account the stress and layering nature of the tight gas sands, to support the development of the reservoir simulation model. The workflow also included a production prediction for different induced hydraulic-fracture half-lengths, which further assists in the target selection.

The workflow was applied to multiple wells from which different sands were selected as the best targets. The paper presents a comparison of the predicted and actual production for these wells.

Integrating Pilot and Lateral Openhole Measurements for Lateral Landing-Point Assessment and Hydraulic-Fracture Design—A Case Study From the Delaware Basin, West Texas

Edgar Velez, Farhan Alimahomed, Elia Haddad, Lance Smith and Jorge Gonzalez, Schlumberger

Well-landing zone selection and a tailored lateral staging and perforation design can have a large impact on well productivity. A successful field development is intrinsically related to both landing and completion optimization, in particular where several stacked producible horizons can be targeted, such as in the Delaware Basin in West Texas. Understanding reservoir and completion properties is key in the decision process for optimal well-landing selection and completion optimization. Two quality factors are defined for this optimization: (1) reservoir quality (RQ); and (2) completion quality (CQ).

RQ encompasses pretrophysical properties, such as porosity, permeability, saturation and TOC. RQ is of most importance in pilot wells to identify and rank the most prolific horizons in stacked horizons but now and then overlooked or dismissed in lateral wells. Typical evaluation techniques to define RQ include using data from basic logs such as triple-combo, but the complexity of the unconventional reservoirs has shown that advanced wireline logs, such as spectroscopy, magnetic resonance and borehole images are needed to accurately quantify petrophysical properties. Completion properties, such as Poisson's ratio, Young's modulus, minimum horizontal stress and natural fractures can also be grouped to define CQ of a given rock. CQ is the main input for the hydraulic-fracturing simulators which aims to achieve the primary objective of determining fracture-height growth, overall geometry and pinch points. Previous revisions have shown the importance of accounting for the anisotropic nature of the unconventional rock and their mechanical properties in which the rock layering intensity and weak interfaces influence the minimum horizontal stress. Hence, data from borehole images, coupled with advance acoustic dipole data and mini-stress tests are instrumental for the calibration of the hydraulic-fracture model.

Placing stages and perforations using log data has had a positive impact on production in vertical and lateral wells, success is based on the use of dipole-sonic-derived anisotropic mechanical properties and stress calculations to improve the frac results, petrophysical rock properties that define the quality of the reservoir and geological information from borehole images, such as fractures and lateral facies variation that either impact the reservoir quality or the completion quality.

In this paper, we will present a case history that shows the integration of an in deep evaluation of various reservoir properties grouped under RQ and CQ factors applied to a pilot and a horizontal well using the latest advanced wireline logs for well-landing selection and completion optimization in West Texas, where lateral and vertical information from the borehole images were use to build a 3D geomodel where the main RQ and CQ properties where propagated aiming to improve the hydraulic-fracture model.

Inversion of High-Resolution High-Quality Sonic Compressional and Shear Logs for Unconventional Reservoirs

Ting Lei, Smaine Zeroug, Sandip Bose, Romain Prioul and Adam Donald, Schlumberger

Interpretation of elastic properties honoring fine heterogeneity has garnered recognition recently in petrophysical analysis, bedding failure prediction, and hydraulic-fracture job design for unconventional reservoirs. Traditional sonic processing assumes homogeneity of the formation over a specific sonic tool receiver aperture length (e.g., at least 2 ft). This assumption may not be appropriate for highly laminated reservoirs where mechanical properties of interest could vary on a significantly finer scale. Additionally, shear slownesses extracted from low- and high-frequency processing are associated with different wavelengths and different rock volumes. For instance, shear slowness logs from a high-frequency monopole transmitter and a low-frequency dipole flexural mode can exhibit different axial resolutions even when using the same receiver aperture length. This apparent inconsistency and the lack of adequate vertical-resolution control render conventional sonic answer products inadequate for properly addressing the high-resolution challenges of unconventional reservoirs.

We have developed a new interpretation algorithm to improve the layer slowness contrast for thinly laminated formations in vertical wells using borehole sonic data from advanced array-based logging tools. This novel interpretation method can yield high-quality and high-resolution sonic compressional and shear (P and S) logs. It is based on a robust downscaling technique that jointly combines all logs processed at different array resolutions. An overdetermined matrix is formulated by taking all convolutional relationships among the different resolution sonic logs. The high-resolution sonic logs (both P and S) are estimated using the Moore-Penrose pseudoinverse method. Finally, the residual is formulated to serve as a log quality-control flag and is used to automatically switch to more reliable low-resolution logs, such as the dipole flexural shear slowness in depth intervals of poor-quality hole data or slow formations.

The algorithm was validated with synthetic logs from finite-difference modeling and was then tested on an unconventional thinly laminated field dataset. The inverted high-resolution P and S logs from sonic field measurements have higher depth resolutions than what the maximum resolution conventional processing can achieve, and are consistent with a higher resolution ultrasonic log from an ultrasonic imaging tool logged in the same well. The field-data application suggests that this downscaling algorithm enhances the spatial resolution and more accurately captures the layer slowness contrast while removing outliers thereby improving the log quality.

The application of this method results in a superior characterization of the acoustic properties of thinly layered rocks than what is obtained with conventional processing. The elastic moduli honor the highly heterogeneous nature of the rock, and thus could improve stress profiling and rock-strength correlations for geomechanical modeling. Operational decisions, such as landing laterals or staging stimulation intervals to avoid weak or strong interfaces will also be better informed.

Investigation of Physical Properties of Hydrocarbons in Unconventional Mudstones Using Two-Dimensional NMR Relaxometry

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Understanding organic matter properties is crucial in characterization of unconventional plays. It is always a challenge for petrophysicists to differentiate and quantify mobile and immobile hydrocarbons in unconventional mudstones. High-frequency (22 MHz) NMR for unconventional rock core analysis has gained industrial acceptance for its high efficiency and high sensitivity to measure very small volume of fluids and solid hydrocarbons in tight rocks. Previous work has revealed that a one-dimensional (1D) NMR T_2 method is insufficient to study organic matter in fresh core samples due to overlapping T_2 signals from both hydrocarbons and water. Coexistence of structurally bound water and solid hydrocarbons in shales leads to a short T_2, in the microseconds range, and further complicates the situation.

In this work, we present the first detailed analysis method using two-dimensional (2D) NMR T_1-T_2 mapping techniques to study physical properties of hydrocarbons in various shale rocks. Combined NMR pulse sequences were used to acquire signals from solids and liquids that contain hydrogen. The 2D T_1-T_2 maps were further processed by removing the map regions that are from water to obtain 1D T_2 distributions for hydrocarbons only. Measurements on mudstone core samples at various temperatures, from 22 to 90°C, show that the relaxation time T_2 of hydrocarbon components increase with temperature due to increasing molecular mobility, but at different rates, implying that hydrocarbons present in different environments (e.g., organic and inorganic pores) within these tight core samples are undergoing different thermal dynamics processes. The T_2 of each hydrocarbon component as a function of temperature was analyzed to calculate the activation energy (Ea) based on the Arrhenius equation for molecular kinetics, and producibility is then estimated accordingly. This NMR method provides petrophysicists with a powerful way to study hydrocarbons that are confined in organic matter, such as bitumen and kerogen, to understand the mechanism of enhanced oil recovery (EOR) in unconventional reservoirs. Furthermore, results from such NMR relaxometry analysis and multiple-heating-rate pyrolysis indicate that the combined techniques are very promising for investigating producibility estimates from the free/adsorbed hydrocarbons present in source-reservoir intervals. Such an alternative approach leads to an analytical protocol for the determination of NMR cutoffs to quantify mobile and immobile hydrocarbons.

Leveraging Digital Rock Physics Workflows in Unconventional Petrophysics: A Review of Opportunities, Challenges, and Benchmarking

Shaina Kelly, ConocoPhillips; Ayaz Mehmani and Carlos Torres-Verdín, The University of Texas at Austin

Rock diagenesis can generate complex pore-lining and pore-filling textures beyond the idealized sedimentary "spherical grain pack" that greatly influence pore-size distributions and transport properties including permeability, capillary trapping, diffusion, and relative permeability. Digital rock physics (DRP), via both direct numerical simulation and pore-network modeling, holds great promise in terms of probing such pore-scale controls on transport, particularly with multiphase flow and sensitivity analysis of time-intensive measurements, such as relative permeability. However, despite advances in microcomputed tomography (micro-CT) and scanning electron microscopy (SEM) techniques, obtaining cost-effective representative elementary volumes (REV) at sufficient resolution that capture dual-scale porosity and surface textures remains a formidable challenge in establishing digital rock physics as a predictive toolset. Furthermore, implementers are faced with several options of numerical solvers, such as finite element modeling, lattice-Boltzmann method, and mass balance-based pore network modeling.

This paper reviews the current status of establishing an REV and upscaling techniques for DRP in tight and/or diagenetically altered rocks, highlighting successful and unsuccessful pore-to-core data benchmarking examples by the authors and the greater literature in terms of static and dynamic properties. The comparison reveals that many DRP efforts do not invoke the menu of more complex transport phenomena that can be modeled, including wettability, thin film flow, reactive transport, and diffusion and osmosis; recommendations for implementing these physics and cases where they should not be neglected are discussed. Furthermore, upscaling and REV likelihood is found to significantly vary with rock type—examples reviewed range from tight gas sandstones to mudrocks and chalks and homogenous/massive to heterogeneous thin-bedded plays. We also identify challenges in honoring pores from multiple lengths scales within the field of view of a single imaging modality and uncertainties associated with image acquisition/processing techniques and advance some practical workarounds.

Overall, in surveying the current state of DRP, the authors recommend a series of best practices for practically and economically leveraging DRP in petrophysical models and highlight tenable advances needed to help to ensure representative and predictive digital rock toolsets for tight rocks. We posit that if a resultant numerical simulation domain is logically tuned to match available core data, including mineralogy, pore-size distribution, and single-phase permeability measurements, then it is conceivable to generate robust relative permeability curve conditions that are impactful in predicting field-scale flow behavior for a particular rock type.

Micro/Nanofluidic Insights on Fluid Deliverability Controls in Tight Rocks

Shaina Kelly, ConocoPhillips; Ayaz Mehmani and Carlos Torres-Verdín, The University of Texas at Austin

Microfludics and nanofluidics have been used in the oil and gas industry as application-specific tools (such as lab-on-a-chip chromatography for multicomponent fluid analysis) and for pore-scale research experiments. The latter technology constructs pore and/or pore-network proxies on lab-on-a-chip devices and investigates the impact of specifically tuned geometric and or material variable(s) on fluid transport via direct observation with microscopy.

This paper reviews micro/nanofluidics findings by the authors and other geoscience and general porous-media researchers related to the impacts of pore size, surface chemistry (wettability), fluid type and composition, and surface texture (roughness) on fluid mobility (effective viscosity), imbibition, capillary trapping, adsorption, and diffusive processes. For example, the authors' microfluidic findings include the presence of a critical surface-roughness value beyond which capillary trapping during imbibition increases drastically due to changes in subpore-scale flow regimes. The authors' nanofluidic findings in silica nanochannels include that the polarity of a fluid and the surface chemistry of a nanoconfinement can lead to an additional contact line friction that causes significant deviations from the continuum Washburn equation for imbibition; these effects can potentially be incorporated through an increased effective viscosity. Collated results for upscaled terms, such as effective viscosity and diffusivity, are reviewed in comparative plots and benchmarked against analogous molecular dynamics simulations, relevant special core analysis findings, analytical solutions (where available), and continuum theories, the goal being to assess a convergence of fluidic findings. Furthermore, there are various device fabrication methods and the micro/nanofluidic results are organized in terms of resultant pore/material types, where studies in crystalline confinements are proxies for clay and intergranular pores and studies in carbon (graphene) confinements are proxies for organic-matter pores and aged oil-wet pore surfaces.

Based on this review, we recommend lab-on-a-chip devices as tools to augment petrophysical laboratory measurements if the following criteria are met:

(1) Practicality/simplicity in design – Fabrication of the devices is facile and replicable such that many disposable devices are available. Examples of chips of varying complexity are offered.
(2) Consistency – One critical variable, such as pore size, material, or fluid composition is tuned at a time to form robust functional relationships, leveraging the critical benefit of controlled fluidic workflows, as contrasted to actual rocks.
(3) Validation – Anomalous fluidic observations must be complemented with theory and/or molecular dynamics and direct numerical simulation methods, again leveraging the powerful benefit that the majority of the fluidic geometry and boundary and initial conditions are known.

Ideally, such lab-on-a-chip devices can be implanted as fluid-transport calibration standards such that the aforementioned fluid behaviors can be mapped back to pore-size distributions and other matrix topology properties already quantified in petrophysical and reservoir quality workflows (e.g., via mercury porosimetry, nitrogen adsorption, NMR, petrography, etc.).

Novel Measurement of Porosity and Saturations of Drill Cuttings Using Nuclear Magnetic Resonance and Infrared Spectroscopy

Ravinath Kausik, Kamilla Fellah, Shin Utsuzawa, Paul Craddock, Mary-Ellen Loan and Shawn Taylor, Schlumberger-Doll Research; Jonathan Mitchell, Schlumberger Cambridge Research

Petrophysical properties, including porosity and saturation, are vital for unconventional resource (shale) characterization, and important for petroleum system modeling, field-planning development, and production matching. But, these properties are challenging to determine in highly deviated (horizontal/lateral) wells drilled in shale due to the absence of routine core and log measurements.

In this paper, we introduce novel approaches to measure porosity, fluid type, and other properties of shale in a 'no-log' environment in horizontal wells, only from measurements of drill cuttings using nuclear magnetic resonance (NMR) and diffuse reflectance infrared Fourier transform spectroscopy (DRIFTS) measurements.

Drill cuttings are irregularly shaped formation material of ~1 to 3 mm in dimensions, brought to the surface by recirculated mud. The determination of porosity of drill cuttings requires the measurement of the pore volume occupied by the fluids and the bulk volume of the entire rock sample. 2D NMR T_1-T_2 measurements at Larmor frequencies of between 12 and 40 MHz are ideal for the determination of the pore volume occupied by components, such as bitumen, oil in organic and inorganic pores, free water, and clay-bound water. The determination of bulk volume of the drill cuttings is challenging due to their small and irregular shape. We address this challenge using two approaches: The first uses multinuclear ^{1}H and ^{19}F NMR (^{19}F and ^{1}H have close but well-separated Larmor frequencies) to estimate both pore and bulk volumes of samples immersed in Flourinert ($C_{10}HF_{22}N$) through changes in NMR signal intensity. The second uses a novel combination of DRIFTS and NMR to compute porosity via density relationships. A DRIFTS analysis of mineral and kerogen mass fractions provides an estimate of matrix density. This, together with measurements of fluid-filled pore volume from NMR and of sample mass, enables determination of matrix volume, bulk volume, and thereafter the fluid-filled porosity.

We demonstrate the successful determination of porosity and saturations on a range of conventional and unconventional samples using both multinuclear ^{1}H-^{19}F NMR and NMR-DRIFTS approaches. We discuss wellsite application of these methods, including cleaning and handling of the drill cuttings. In summary, we demonstrate novel ways of determining petrophysical quantities, such as porosity and fluid saturation in a fast and accurate fashion to help obtain a more complete picture of the reservoir quality in lateral wells from drill cuttings, in an otherwise data-poor environment.

Quantification of Uncertainties Related to the Assessment of Free and Adsorbed Gas-in-Place for Shale-Gas Reservoirs

Rafay Ansari, German Merletti, Peter Armitage and Pavel Gramin, BP

Determining the potential of shale-gas reservoirs involves an exhaustive process of calculating the volume of hydrocarbon originally in place. The calculation relies principally on the core-wireline log calibration, with core data regarded as the ground truth. Inconsistency in sample preparation, protocols and analytical techniques between commercial core analysis laboratories adds significant uncertainty to the assessment of both free and adsorbed gas.

Experimental testing on twin samples was conducted at three core analysis laboratories to understand the source of differences in measurements, such as porosity and water saturation that affect free-gas calculations. The impact of mesh size on crushed rock samples is also assessed. On average, relative differences of 20% in water saturation and 10% in porosity were observed between laboratories, leading to differences of 35% in calculations of free gas-in-place.

Methane adsorption testing was conducted to study the changes in Langmuir parameters in samples with a wide variety of water saturations, clay content, total organic content and at different experimental temperatures. It was found that the storage capacity of adsorbed gas artificially increased by a factor of two to three when experimental temperature exceeded the boiling point of water. This increase is related to the expulsion of clay-bound water and subsequent availability of clay surfaces for methane adsorption.

Total gas-in-place is the sum of free- and adsorbed-gas volume estimates. The interaction and overlap of pore space between these two volume components is also important to consider. It is proposed to use a simplistic monolayer-based correction of volume of adsorbed gas from the free-gas volume based on a composite pore-size distribution from scanning electron microscopy (SEM) point counting and nitrogen adsorption data.

Multiple scenarios for total gas-in-place due to the aforementioned uncertainties were compared against gas volume reported by a direct volumetric approach. This approach involves acquiring pressurized sidewall core at reservoir conditions and measuring this gas volume in controlled laboratory conditions. The controlled depressurization of reservoir gas helped in separating the volumes and composition of the free and adsorbed gas. The direct approach was also used to understand which laboratory protocol and sample preparation technique provided the most robust results. This study has elucidated methods to reduce the uncertainty in gas-in-place calculation and better understand resource distribution in dry-gas source rocks.

Quantifying Bitumen Plugging Using Geochemical and NMR Logging on Tight Gas Reservoir

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This paper addresses the identification, quantification and the implications of bitumen in a deep (>5,000 m) tight gas reservoir in the Amin formation. This formation was deposited in aeolian, sabkha and fluvial-dominated environment. It has an average porosity of 6 p.u. and intrinsic permeability of less than 1 mD. Consequently, hydraulic fracturing is required to yield economical production rates. The bitumen, which is believed to result from oil-to-gas cracking process, poses an additional challenge as it directly degrades storage capacity, destroys the permeability and results in erroneous computed saturations. It is, thus, imperative that these factors are taken into consideration in reserves and productivity predictions that could ultimately impact overall development planning.

This paper details an evaluation workflow that was devised to directly quantify bitumen and provide accurate volumetric analysis. The methodology is based on the integration of the triple-combo, NMR and pulsed-neutron spectroscopy logs. The NMR effectively identifies bitumen through its reduced porosity against density log. This difference arises because NMR is incapable of measuring fast relaxation of the hydrogen contained in bitumen. However, the NMR porosity is also reduced due to the reduced hydrogen index of gas. Spectroscopy analysis quantifies the concentrations of various elements contained in the reservoir rocks. This includes carbon concentration contained in the rock, gas and bitumen. The total organic carbon (TOC) is derived by subtracting inorganic carbon contained in the rock. The measured TOC is essentially due to the bitumen as its negligible in gas. The integration of these different measurements allows effective means to differentiate and quantify different pore constituents contained in our reservoir.

Integrated volumetric analysis was carried out using triple-combo, NMR and geochemical spectroscopy logs. The analysis provided the actual total porosity, bitumen volume and true gas saturation. The study showed that the reservoir contains pyrobitumen volumes up to 5%. The log predictions were verified against pyrolysis and thin-section analyses on core samples from similar wells. Integrating log and core analyses results with production logs directly demonstrated the influence of the bitumen presence on the well productivity. Repeating the analysis in different areas of the reservoir further established the uneven bitumen distribution and its consequences across the reservoir. This observation provided the basis for more representative static and dynamic modelling.

Quantifying the Impact of Geochemistry, Temperature, and Pressure on the Water-Adsorption Capacity and Wettability of Kerogen Using Molecular Simulations and Experimental Measurements

Archana Jagadisan and Zoya Heidari, The University of Texas at Austin

Inter- and intra-molecular forces acting on the surface of kerogen affect its interfacial properties such as wettability. Wettability of kerogen directly influences the multiphase fluid-flow properties, water production, and electrical resistivity (e.g., low-resistivity pays) of organic-rich mudrocks. The oxygen and hydrogen contents of kerogen vary with change in kerogen type and thermal maturity, which can affect the water adsorption capacities of kerogen. Moreover, high temperature and pressure reservoir conditions can affect the adsorption properties of kerogen. Previous publications documented molecular dynamics simulation for quantifying wettability of kerogen. These publications used simplified kerogen structures which do not capture the heterogeneity and complexity of kerogen. Recently, we experimentally demonstrated that kerogen wettability varies significantly with thermal maturity and that it could be water-wet at low thermal maturities. However, these experiments did not quantify the impacts of kerogen type and reservoir temperature/pressure conditions on kerogen and mudrock wettability. Therefore, the objectives of this paper include (1) quantifying the impacts of kerogen molecular structure and composition on water adsorption capacities, (2) quantifying the impacts of reservoir temperature/pressure on water-adsorption capacity of kerogen using molecular dynamics simulations, and (3) cross-validating the wettability results from molecular simulations with experimental results.

We use molecular dynamics simulations and experimental work to achieve the aforementioned objectives. The inputs to the molecular simulations include models of kerogen, methane, and water molecules in a cubical simulation box with periodic boundary conditions. We use realistic molecular models of kerogen that bear structural resemblance to experimentally determined kerogen structure. The molecular structure representative of different kerogen types at different thermal maturities honor the O/C and H/C ratios based on the van Krevelen diagram. The outputs of the simulations include water adsorption capacities of kerogen at different kerogen types, thermal maturities, and temperature/pressure conditions. Surface adsorption processes are modeled for temperature and pressure conditions ranging from 298 to 380 K and 10 to 50 bars, respectively. The results are compared with experimentally determined wettability using the sessile-drop method on isolated pure kerogen samples from two formations, which contain Type II and Type II/III kerogen.

Simulation results showed that the water adsorption capacity of kerogen increases 15% with 10% increase in oxygen content. The increase in the adsorption capacity is attributed to the strong attraction between oxygen containing functional groups in kerogen and water. Increase in temperature from 298 to 380 K increased the water adsorption by two-fold, whereas increase in pressure had the reverse effect. The results obtained from molecular simulations are in agreement with experimental results of kerogen wettability. The documented results and workflows contribute to improving formation evaluation of organic-rich mudrocks by providing (a) quantitative information about wettability of kerogen, and (b) a reliable workflow for quantifying wettability of kerogen at any given kerogen type, geochemical property, and reservoir condition. The outcomes of this paper can also potentially contribute to understanding the role of organic content and its geochemical properties in fluid-flow mechanisms, which can be used to predict water production in organic-rich mudrocks.

Reliable and Fast Saturation-Dependent Relative Permeability Measurement in Tight Rock Samples

Andres Gonzalez, Saurabh Tandon and Zoya Heidari, The University of Texas at Austin; Pavel Gramin and German Merletti, BP

Reliable laboratory assessment of water and gas saturation-dependent relative permeability in low-permeability rock samples can be challenging. In ultratight samples, the use of dynamic steady-state or unsteady-state methods are very time consuming. The “permeability jail” phenomenon results in extremely low flow rates even for very high flow pressures that are difficult to achieve and accurately measure using conventional pumping systems. Additionally, unsteady-state methods often fail to address viscous and capillary effects, which dominate the relative permeability results in low-porosity and low-permeability core samples. On the other hand, stationary-liquid relative permeability methods require a core-desaturation step prior to measurement of effective permeability. The choice of desaturation technique can significantly affect reliability of relative permeability measurements. The objectives of this paper are: (a) To compare the dynamic unsteady-state and stationary-liquid methods using two desaturation techniques, porous plate (high-pressure membranes) and centrifuge desaturation for relative permeability measurements; (b) improve relative permeability estimates by monitoring fluid distribution along the core length using nuclear magnetic resonance (NMR) measurements; (c) develop a relatively fast and reliable experimental workflow for relative permeability measurements in tight sandstone formations; and (d) to establish the range of rock properties for which different methods provide reliable results.

First, we measured the gas and brine absolute permeabilities of each sample. Subsequently, we desaturated the cores to different saturation levels using centrifuge and high-pressure membranes. At each saturation level, we measured the effective gas permeability of each sample using the pulse-decay technique. We measured NMR T_2 (spin-spin) distribution to quantify fluid saturation at each desaturation stage. Additionally, we measured the saturation profile along the core length at each stage to monitor and control fluid distribution in the core samples. We corrected for the effect of saturation gradients by rotating the orientation of the sample in the centrifuge core holder by 180° during certain time intervals. Finally, we used the unsteady-state technique for measuring gas and brine relative permeability curves for the comparison purposes.

We applied this workflow to eight tight rock samples collected from multiple tight gas reservoirs. The core samples cover a wide range of rock quality with total porosity and gas permeability ranging from 5 to 12% and 0.009 to 2.2 md, respectively. NMR saturation-profile measurements revealed the presence of saturation gradients along the core length after centrifuge desaturation in all samples. The maximum relative difference in water saturation along the core length was up to 77%, leading to relative errors of up to 90% in relative permeability estimates. Rotating the samples by 180° and further desaturation completely mitigated the influence of saturation-profile gradients on measured relative permeabilities.

This study provides a new workflow to estimate relative permeabilities in tight samples with a wide range of porosity and permeability values. The proposed workflow enables 66% faster measurements compared to conventional steady-state techniques and much more reliable measurements compared to those obtained from the unsteady-state method. Furthermore, it provides robust and accurate gas relative permeability measurements for the range of rock quality included in this study.

Reservoir Producibility Index (RPI) Based on 2D NMR T_1-T_2 Logs

Ravinath Kausik and Tianmin Jiang, Schlumberger-Doll Research; Lalitha Venkataramanan, Schlumberger; Albina Mutina, Schlumberger-Doll Research; Erik Rylander and Richard Lewis, Schlumberger

The role of logging in vertical pilot wells in unconventional tight oil shale plays is to determine the reservoir quality, based on which the horizontal drainholes can be placed. The reservoir quality (RQ) of shale is characterized by quantities related to hydrocarbon storage and producibility, such as porosity, total organic carbon (TOC), fluid saturation, wettability, permeability, etc. It is now well recognized that among the different components constituting the TOC, the kerogen and bitumen adsorb the oil and reduce permeability by clogging pore throats, respectively, and, therefore can be considered negative reservoir quality indicators. The light-hydrocarbon component is distributed between a low-mobility fraction in the oil-wetting kerogen pores and a higher mobility fraction in the mixed-wet inorganic matrix porosity. The water phase is also distributed between the clay-associated bound-water fraction and the more mobile water in the mixed-wet pores of the inorganic matrix. Identifying these different components and their environments is vital for determining the reservoir quality.

Recently, a new metric, namely the reservoir producibility index (RPI) that treats the light hydrocarbon (oil) as a positive reservoir quality (RQ) indicator and kerogen, bitumen as negative RQ indicators, has been introduced for tight oil organic shales. The measurement of the RPI requires quantitative fluid typing of the different components of organic carbon and water phases, downhole. We demonstrate measurement RPI logs through the application of 2D NMR T_1-T_2 for determining the light hydrocarbon, in combination with spectroscopic measurements for total organic carbon.

The 2D NMR T_1-T_2 logs separate the different fluid fractions using the sensitivity of these measurements to molecular mobility. In combination with spectroscopy logs the RPI is obtained as a continuous depth log in tight oil pilot wells. To determine the production potential along the well, the total log porosity was compared with the porosity of cores with the difference reflecting the fluids that escape core retrieval. This quantity which is a good proxy for the producible fluid fractions is shown to be positively correlated to the Reservoir Producibility Index measured from the logs.

In conclusion, we demonstrate the combination of 2D NMR T_1-T_2 and spectroscopy logging to obtain a continuous log of the reservoir producibility index in tight oil pilot wells to help determine the depths to land the horizontal drain-holes. This method is driven by the ability of 2D NMR T_1-T_2 technique to quantitively identify the fluid fractions and their confining environments, especially the light oil in the organic kerogen porosity. We demonstrate the value of the RPI in a tight oil well in the Permian Basin by showing a relatively strong correlation with estimated oil producibility.

TGIP NMR Measurements of the Appalachian Unconventional Shale Based on 2D T_1-T_2 NMR Logs

Natalie Uschner-Arroyo, Schlumberger; Ravinath Kausik and Lalitha Venkataramanan, Schlumberger Doll Research; Tianmin Jiang, Erik Rylander and Richard Lewis, Schlumberger

Shale-gas resources are more difficult to evaluate than traditional gas reservoirs, as the hydrocarbon exists not only as pore-filling free gas, but also as adsorbed gas on high surface-area kerogen. Each of these phases have a different density and their downhole NMR signals cannot easily be separated. In addition, the effective hydrogen index of the hydrocarbon phase cannot be determined. The Langmuir adsorption isotherm has been the preferred method for estimating gas-in-place in unconventional shales for many years. However, operators have not been able to consistently history match gas production results based on the Langmuir method, due to the uncertainty of the measurements, interpreted results and assumptions in modeling. This is especially true in the United States Appalachian unconventional shale plays, where the amount of free and adsorbed gas calculated from multimineral models and Langmuir isotherms, is low as compared to production history matching. Additionally, since measurements of Langmuir isotherms require laboratory core investigations which are not always performed, and the limited number of measured isotherms are often insufficient to characterize the heterogeneity of the entire resource.

The recently introduced TGIP-NMR method enables the direct conversion of NMR measurements into total gas-in-place (TGIP) by counting hydrogen nuclei directly, circumventing the requirement to know the hydrogen index, pore size, pore pressures and formation temperature for gas-in-place determinations. This paper demonstrates the successful calculation of the TGIP-NMR methodology on an Appalachian unconventional shale play, involving a cluster-based interpretation of continuous T_1-T_2 logs for a more accurate measurement of the clay-bound water and gas fractions. This method provides superior performance in comparison to T_2-cutoff-based 1D NMR methods or applications of multimineral saturation models (where estimates of salinity, R_w, and knowledge of hydrocarbon parameters are required).

While the TGIP-NMR method has emerged as a new candidate for the determination of gas-in-place in unconventional shale plays, it is important to be cautious about its limitations. NMR T_1-T_2 based TGIP can provide an accurate answer in high kerogen high-porosity zones of unconventional shales. However, TGIP-NMR method is also very sensitive to the uncertainties in the measurement of the volume of water in the shale. With the very low volumes of water in the US shale-gas plays, an accurate estimate of clay-bound and irreducible water based on a T_1-T_2 analysis is essential for the TGIP calculation. Additionally, in very low porosities, approximately 2% p.u. or less, the results from TGIP could be suspect due to noise in the T_1-T_2 measurements.

Thermal Maturity-Adjusted Logging in Shale

Paul R. Craddock, Schlumberger-Doll Research; Richard E. Lewis, Schlumberger; Jeffrey Miles and Andrew E. Pomerantz, Schlumberger-Doll Research

Petrophysical interpretation of downhole logs requires accurate knowledge of matrix properties. In organic-rich mudrocks (commonly termed shale), the presence of abundant kerogen (solid, insoluble organic matter) has a particularly large and variable impact on matrix properties. Kerogen is compositionally quite different from the inorganic minerals that comprise the remainder of the matrix, so matrix properties can be highly sensitive to kerogen properties. As a result, seemingly minor errors in prescribed kerogen properties may yield large errors in the interpretation of organic-rich formations. For example, a 0.1 g/cm^3 error in assumed kerogen density can yield a relative error in density-porosity of more than 20%. Unfortunately, relevant petrophysical properties of kerogen are poorly known, in general, nearly always unknown in the shale of interest, and otherwise impractical or impossible to measure.

Here, we determined the petrophysical properties of more than 50 kerogens with thermal maturity ranging from immature (vitrinite reflectance equal to 0.5% R_o) to dry gas (4% R_o) and representing three continents, eight major sedimentary basins, and 350 million years in age. Measurements were performed on purified kerogen samples obtained by a time-consuming acid-demineralization procedure. The determined kerogen properties include measured chemical (C, H, N, S, O) composition and absolute density, as well as calculated nuclear properties, such as apparent log density, hydrogen index, thermal and epithermal neutron porosities, macroscopic thermal-neutron capture cross section (sigma), and macroscopic fast-neutron elastic-scattering cross section. All but one kerogen properties are found to vary substantially across the dataset, commonly by a factor of two or more. For kerogen samples relevant to the petroleum industry (predominantly Type II with thermal maturity ranging from immature to dry gas), it is found that each petrophysical property is controlled mainly by thermal maturity, with differences between basins having little effect. As a result, universal curves can be established relating the studied kerogen properties to thermal maturity, and the curves apply equally well in all of the prolific basins studied here. These universal curves enable robust and accurate predictions of kerogen properties in any shale formation from knowledge of one common parameter—the thermal maturity—circumventing the need for dedicated, time-consuming preparation and analysis of kerogen isolates in the formation of interest.

The industry has workflows for 'matrix-adjusted logging', where default matrix properties are replaced with values measured specifically in the formation of interest. As an improvement on this concept, we hereby propose 'maturity-adjusted logging', in which default kerogen properties in shales are replaced with refined values based on measured thermal maturity. The thermal-maturity adjustment can be incorporated into optimal matrix properties using measurements of mineralogy and organic content where available, whether from core, cuttings, or geochemical logs. This 'maturity-adjusted logging' procedure is globally applicable to the evaluation of shales of interest to the petroleum industry, and this automated procedure results in a more accurate, consistent, and confident estimation of formation parameters including porosity, saturation, and hydrocarbon-in-place.

Unraveling Discrepancies in Array Laterolog and Induction Resistivity Response In Unconventional Shale Reservoirs

Isabelle Dubourg, Richard Leech, Nasar Khan, Martin G. Lüling and Gong Li Wang, Schlumberger

Much of the current United States (US) domestic oil and gas production comes from land-based shale reservoirs, which, in previous decades, had been considered unprofitable and therefore economically uninteresting. To successfully manage this significant resource, a good understanding of the formation properties and fluid distribution is required. As with saturation determination in conventional reservoirs, resistivity-based methods are commonly used to evaluate unconventional reservoirs. Historically, such fields have been appraised by a mix of laterolog and induction resistivity devices, dependent on the drilling environment, formation properties and, in some cases, prior precedent.

However, this drive to examine tighter and finer oil- and gas-bearing formations has highlighted a discrepancy arising from the use of different styles of resistivity measurements. In unconventional shale reservoirs, systematic differences in shale resistivity response have been observed between laterolog and induction devices, which, in some cases, have resulted in considerable variations in computed water saturation. Such discrepancies need to be properly understood and accounted for when appraising reservoir potential.

It is documented in the literature that in a vertical well drilled through a horizontally laminated formation, such as a shale, laterolog measurements frequently exhibit a systematically higher resistivity than induction measurements in the same formations. A possible explanation attributes this phenomenon to the different sensitivity of each measurement type to horizontal and vertical formation resistivities. Another possible hypothesis for the systematic high-reading laterolog versus induction resistivity in shale formations is the near-wellbore alteration caused by an electrochemical interaction of the shale at the borehole wall exposed to drilling fluids. More recent studies show that the dielectric properties of unconventional shale plays affect the quadrature signals of array induction measurements and, with the introduction of multifrequency dielectric measurements, severe dielectric dispersion has also been observed in certain shale formations.

Whenever electromagnetic array responses feature unexplained phenomena, log simulations are used to first reproduce and then understand the physics of the phenomenon. Once an appropriate algorithm has been developed, it can be validated using a comprehensive suite of field log data acquired within the same borehole.

This paper examines how to resolve the discrepancies observed between array laterolog and induction resistivity measurements in low-permeability, uninvaded shale formations that are commonly developed as unconventional resources in the continental US. We demonstrate how, with the help of novel processing algorithms, these resistivity response discrepancies can shed new light on, and thus change our appraisal of unconventional shale reservoirs.

MACHINE LEARNING

A Deep-Learning Approach for Borehole-Image Interpretation

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Borehole-image interpretation aims to evaluate the dip magnitude and azimuth direction of geological features detected along the well and classify them. Manual interpretation of borehole images can be time-consuming and, sometimes affected by inconsistencies derived by different interpretation approach used.. Thus, there is a need for a robust automatic or semi-automatic approach to reduce the manual labor and increase efficiency and consistency.

In recent years, deep neural networks (DNN) have been successfully deployed to address a variety of challenging problems in several fields, including computer vision. We have developed a DNN-based supervised-learning technique for borehole-image interpretation to automatically detect and classify geological features from borehole images acquired from Formation MicroImager (in water-based mud) and QuantaGeo (in oil-based mud) and in turn, provide robust estimates of the features' dip and azimuth. This machine-learning (ML)-based interpretation workflow requires the geologist to label a small section of features in the well for ML training; following which, the trained machine provides labeling for the remaining depths of the well. Such machines may also be trained on previously interpreted wells with similar characteristics.

Our preliminary results show that deep-learning models can accurately detect a diverse and complex set of image attributes without manual intervention. Certain geological features can occur sparsely, challenging a direct supervised-leaning approach; to address this challenge we discuss the utility of employing a semisupervised-learning paradigm.

A Machine-Learning Framework for Automating Well-Log Depth Matching

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Depth matching well logs acquired in different logging passes in a single well, which is essential to process and interpret the log data, has been a longstanding challenge for the industry. It has become even more important in the era of data analytics, where data need to be properly curated before they can be used. The existing approaches employed in commercial platforms are typically based on classical cross-correlation and covariance measures of two signals, followed by manual adjustments. These solutions do not satisfy the rising demand to minimize user intervention. To proceed towards automated data interpretation, we aimed at developing a robust and fully automatic algorithm and workflow for depth matching gamma-ray logs, which are commonly used as a proxy to match the depth of other well logs measured in multiple logging passes within the same well. This was realized by a supervised-machine-learning approach through a fully connected neural network. The proposed solution uses clever data formation and augmentation, which permits to obtain, from a very limited pool of manually labeled data, a sufficiently large dataset for training. To push the performance at a fully automated level, we employ different stacking and filtering methods, leading to well-synchronized signals and therefore a good depth match between logging passes.

As it is unrealistic to expect a perfect model from the initial training with limited manually labeled data, we developed a continuously self-evolving depth-matching framework. This was realized by deploying the trained depth-matching engine to the Cloud as a microservice. The users submit depth-matching requests to the remote server and get the results back to the front-end. After extensive studies on the different statistical metrics including correlation, earth mover distance, dynamic time warping, recurrence dissimilarity, and cross approximate entropy, etc., we developed a dedicated metric by combining a few different algorithms. We use this metric to quantify the quality of the returned results. The users review the results and do manual adjustments if some intervals are not ideally depth-matched by the engine. Those manual adjustments are sent back to the database on the Cloud, and the framework retrains the machine learning model based on the updated database. The newly trained model can be validated and compared against existing models using the developed metrics system. Enhanced models are committed into the model pool that is part of the service. As users keep using the service, the depth-matching framework is anticipated to automatically and continuously improve in performance which eventually leads to an optimal and fully automated depth-matching workflow.

A key aspect of the developed framework is its generalization potential because it is agnostic of the signal type. It could be easily applied to other log data, especially when the correlation thereof, is not obvious, provided that a sufficiently large volume of labeled data is available.

This framework has been prototyped and tested on field data. A demonstration will be shown in the presentation.

A Multiscale Path for the Characterization of Heterogeneous Karst Carbonates: How Log-to-Seismic Machine Learning Can Optimize Hydrocarbon Production

Francesco Bigoni, Marco Pirrone, Fabio Pinelli, Gianluca Trombin and Fabio Vinci, Eni S.p.A.

The accurate modeling of carbonate reservoirs is a longstanding challenging task due to the difficulties in capturing and characterizing their intrinsic multiscale heterogeneities. Unpredictable variations in pore-size distribution, in pore geometry and connectivity strongly influence both reservoir rock properties and fluid-flow behavior. This fact often results in discrepancies between the petrophysical characteristics estimated from cores and/or logs and distributed in the 3D model, and the actual dynamic performances of wells and reservoir.

This paper introduces a novel fully integrated machine-learning workflow, based on a multidimensional/multiscale approach, aimed at obtaining a robust static and dynamic characterization of carbonate reservoirs. In detail, openhole logs, microresistivity images, production logging and pressure transient analyses are used to simultaneously depict the rock characteristics and the associated dynamic behavior at well-scale. Then, a supervised classification allows to build a link between the aforementioned reservoir properties and particular seismic attributes extrapolated at the well locations. Finally, the interesting carbonate features are distributed into the entire 3D reservoir model through a fit-for-purpose neural-network algorithm that exploits the full seismic cube.

The complete methodology is presented by means of a study performed on an oil-bearing carbonate reservoir, characterized by an extremely high heterogeneity due to diagenetic processes, in particular to karstification. These are responsible of important permeability enhancements in low-porosity intervals that are critical for production optimization and reservoir management purposes. At well-scale, karst features are characterized by an advanced image log interpretation mainly focused on the quantification of connected vugs. Moreover, multirate production logging and well-test analyses are accomplished in order to evaluate the proper permeability values in such karst intervals where core calibrations and log-based predictions are not reliable. Next, karst-related vug densities, flow-calibrated permeabilities and selected seismic parameters, such as lineaments (from continuity and curvature attributes), and the outputs of spectral decomposition have been used in a neural-network process as sets for log-to-seismic learning and validation phases. In the end, the network is run to distribute the karst-related permeability enhancements into the 3D reservoir model according to the driving seismic attributes.

The final outcomes of the workflow are karst probability maps that are deemed fundamental to guide new wells location and trajectory. As a matter of fact, two proof-of-concept case histories have demonstrated the reliability of the approach. The newly drilled wells with paths guided by these prediction-maps have intercepted the desired karst intervals as per the subsequent image log interpretation. The latter has been also used to define the proper perforation strategy including low-porosity intervals but with high vug density. Well tests and multi-ate production logging interpretations have proven the outstanding well performances associated with permeability values in the order of a Darcy right through the karstified rock. Based on these successful results, the ongoing drilling and perforation campaign of 10 other wells is built upon this comprehensive methodology.

Advanced Petrophysical Applications for the Australian Mining Industry

Jennifer Market, Lloyd's Register; Huw Rossiter and Brenton Armitage, MPC Kinetic

In the past, much of the petrophysics done in the Australian mining industry has been based upon gamma ray, single-point density, resistivity, and acoustic televiewers. Common uses of petrophysical data include locating the top and bottom of the seam/ore, determining the water level, mapping fractures and faults, computing hardness, and facies analysis. However, the industry is moving toward more advanced applications, such as improved methods of understanding the porosity and permeability of the rocks, 3D mapping of stability, and the use of petrophysical measurements as a cost-effective means of supplementing or even replacing traditional assay methods.

This paper begins with a brief introduction to the mining environment as compared with the modern oilfield environment. While petrophysical data acquisition in East Australian coal mines is not so far removed from shallow oilfield land wells, other operations, such as the Pilbara Iron Ore fields of Western Australia are a very different world—thousands of holes are drilled, each generally less than 60 meters. Assays (geological analysis of material collected from the hole) are the primary reference data. Costs to log are low, and many processes (data interpretation, delivery of logs, etc.) are automated.

Next, there is a review how gamma-ray, density, neutron, resistivity, and caliper measurements are used throughout the Australian mining industry, paying some attention to the challenges of using classic tool designs, such as 16/64 normal resistivity tools and single-point (uncompensated) density. Sonic, electrical imaging, and acoustic televiewers/scanners are the next tier of measurements; these are used for fracture/fault mapping, ground stability, hardness and seismic integration.

Finally, we will discuss the latest wave of technologies to be gaining ground in the Australian mining market, including NMR, VSP, and elemental spectroscopy. The introduction of these advanced petrophysical measurements in Australian mining is opening the door for exploiting new applications, many centered around "big data" or machine-learning techniques, such as automated facies identification, high-resolution mapping of both major and minor minerals, and 3D visualization of ore properties.

Artificial Intelligence Applied to NMR Logging for Rock and Fluid Typing in Heavy Oils

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Nuclear magnetic resonance (NMR) wireline logging and data post-processing technologies are continuously evolving, making significant contributions to rock, fluid typing, formation evaluation and characterization of the near-wellbore zone. In heavy-oil fields, however, NMR logging is known to provide a very low permeability index, poor reliable oil typing, and thus poor oil saturation and viscosity determinations. Several attempts have been made to improve NMR results, mostly with limited success. The main reason lies not necessarily in the selection of the data-acquisition parameters and sequences for a single-frequency or multi-frequency tool, but in the way that the data are post-processed.

The present study refers to a heavy-oil field in Turkey where NMR data were acquired in a well with a centralized, single-frequency wireline tool in a 6-in. borehole, drilled with water-based mud in a freshwater carbonate reservoir. The generated T_2 log was analyzed in a traditional way to obtain the NMR total porosity and its partitions based on standard cutoff values. The permeability, calculated from the Timur-Coates equation was expectedly underestimated, then the heavy-oil T_2 spectra fall within the capillary bound-water region, numerically enhancing the bound-fluid porosity partition and decreasing the permeability. No reliable oil T_2 component could be visually identified.

The newly proposed post-processing steps to obtain the heavy-oil saturation start by deconvolving the T_2 spectra, using blind source separation (BSS), based on independent component analysis (ICA), which is an artificial intelligence tool. The deconvolution results show that a specific independent component corresponds to the oil, based on its T_2 peak value at 12 ms—the expected T_2 oil-peak response calculated from the job planner/simulator. The oil saturation was calculated depth-wise as the ratio of the area under the heavy-oil T_2 spectrum divided by the NMR total porosity. Results show an excellent agreement between oil saturation and shallow- and deep-resistivity curves. Furthermore, the permeability index was corrected by assigning the total heavy-oil volume to the free-fluid volume. This step relies on the understanding that heavy-oil -and any hydrocarbon's NMR responses- should not be evaluated by means of cutoff values.

The present results demonstrated the usefulness of NMR logging technology in the characterization and evaluation of a heavy-oil reservoir oil. NMR data post-processing based on artificial intelligence tools, like BBS-ICA, proved to be adequate. For the reasons above, NMR logging has been proposed and acquired in additional wells in the same field.

Automated Formation-Top Labeling and Well Depth Matching by Machine Learning

Shirui Wang and Qiuyang Shen, University of Houston; Yu Liu and Xianping Wu, Shell; Xuqing Wu and Jiefu Chen, University of Houston

Aligning two or more logging curves in depth obtained from different wells is essential to the formation evaluation and drilling control. If the offset varies, it influences the investigation and comparison of drilling parameters from different wells. All labeling tasks have one similar objective, which is to pick out the same formation tops across different wells. Generally, the geologists evaluate the logs and determine the depth of formation tops through experiential knowledge. This kind of practice leads to imprecise labeling results with increased uncertainty due to the lack of rigid evaluation criteria. Motivated by the state-of-the-art data-analysis techniques and the trend of digitalization and drilling automation, a machine-learning-assisted strategy for the formation-top labeling and well depth matching is proposed in this study.

The conventional signal-processing approach is insufficient to solve the formation depth-matching and top-labeling problem due to the unpredicted shift, stretch, or distortion in multiple logging curves. Dynamic time warping, a classical signal-alignment approach, is sensitive to the choice of the signal features being extracted and is not well suited for dealing with missing signals.

In this study, advanced machine-learning techniques are explored to solve the signal-alignment issues. The objective is to perform the depth match for a whole well section automatically by using machine learning to detect and label each formation top. The artificial neural network is selected by this study to extract features indicating changes between formations based on a historical gamma-ray dataset with manually labeled formation tops and corresponding depth. A supervised-learning strategy is deployed to train the neural network for resolving the formation-top labeling problem automatically given a new gamma-ray curve. The robustness of the system is further enhanced via the combination of statistical approach governed by the Bayesian theorem.

Cutting-edge machine-learning techniques have opened a new era for drilling automation and formation evaluation. Our field-case studies demonstrate the adaptiveness and accuracy of the proposed neural-network approach for solving the formation top-labeling and depth-matching problem.

Automated Resistivity Inversion and Formation Geometry Determination in High-Angle and Horizontal Wells Using Deep-Learning Techniques

Hu Li, Maxwell Dynamics Inc.; Gang Liu, Shansen Yang, He Huang, Mingzong Dai, Yuanshi Tian, CNPC Logging, LWD Center

In high-angle and horizontal (HAHZ) wells, resistivity measurements are often complicated by environmental effects, such as adjacent beds, relative dip angle, invasion, and resistivity anisotropy. Also, abnormal responses, e.g., polarization horns, are frequently observed when the tool approaches or penetrates the formation boundary. Thus, before any further quantitative petrophysical interpretation, one has to determine and remove the geometrical and environmental effects. However, this can sometimes be a challenging task. On the one hand, it is questionable or incorrect to apply environmental-correction algorithms to the measurements without identifying the geometric structure and the controlling environmental factor. On the other hand, it is not efficient for experts to determine these effects manually; besides, subjectivities may exist because of human intervention.

In this paper, we present a new deep convolutional neural-network (CNN) learning framework to automatically identify the controlling pattern, i.e., the geometric structure and the decisive environmental factor. The inputs are the approximated dip angle and raw logs from logging-while-drilling (LWD) measurements, such as the measured depth (MD), gamma-ray, and resistivity measurements. The outputs are the controlling patterns, which are divided into two major categories: Boundary-dominated patterns and environmental-effects-dominated patterns. The former includes single-boundary pattern, double-boundary pattern, and approaching-sliding-leaving pattern (i.e., the bottomhole assembly (BHA) may slide along the interface of two layers for a short distance before penetrating it). The latter consists of anisotropy pattern, invasion pattern, and shoulder-effects pattern. The training phase takes well-defined features as class labels and numerical simulated LWD logs as the training set for machine learning. Then, the CNN is performed to extract representations of the referenced features from the data for pattern identification and data interpretation.

Meanwhile, a set of inversion-based correction algorithms are also developed to derive the formation "true" resistivity as well as the geometric structure after the recognition of the controlling pattern. Accurate and efficient forward-modeling algorithms are needed in these inversions. For most of the patterns, the analytic solution would be enough for this purpose. However, for the invasion pattern, where the solutions of Maxwell's equations in the cylindrical-layered medium are involved, the numerical modeling could be time-consuming. A pr-trained neural network, which is a type of deep-learning (DL) method, where the inputs are the invasion depth, resistivities of the invaded zone, and resistivities of the uninvaded zone, and the outputs are the resistivity measurements, is employed to implement the real-time data processing.

The proposed scheme has been tested on multiple datasets that were simulated or recorded in HAHZ wells. The deep CNN gives a reliable controlling pattern, on which automated resistivity inversion can be implemented. Using the deep-CNN framework, feature extraction for controlling pattern identification can be done via the DL method without human intervention, thus, reducing the subjectivity in interpretation significantly. Furthermore, in our development, the dataset, which is recognized as a specific pattern by the user, can be added into the database for further training purposes.

Automatic Interpretation of Well Logs With Lithology-Specific Deep-Learning Methods

Xiaowen Zhang and Joaquin Ambia, The University of Texas at Austin; Jochim Strobel, Wintershall; and Carlos Torres-Verdín, The University of Texas at Austin

Accurate and reliable interpretation of well logs often requires a high level of expertise from a petrophysicist along with enough relevant logging measurements. As an alternative and complementary approach, deep learning has been proposed as a suitable strategy to capture some of the experiential knowledge gained from petrophysical interpretations, as well as the physical and heuristic models often used for interpretation.

In this study, we start with a set of wells that have been interpreted by expert petrophysicists and apply machine-learning methods to reproduce the interpretation of a subset of the measurements, using the rest of the set to train different deep artificial neural networks (ANN). All measurements have been subject to quality control to mitigate the effects of noisy and inadequate data in the analysis.

Some of the questions we attempt to answer here, as a guide for future field applications of ANNs are: how much data does the petrophysicist need to explicitly interpret before relying on ANNs? What is the best suited deep-learning network architecture? Can the implementation of ANNs in tandem improve results? If we answer the previous questions for a specific formation in a specific reservoir, how much can the ANNs be generalized? In this study, all the wells come from the same hydrocarbon reservoir and intersect multiple formations. We focus on estimating clay fraction (VCL), effective porosity (PHIE), water saturation (SW), and permeability (K).

A comparison is made of the performance of different algorithms, including standard artificial neural networks (ANNs), convolutional neural networks (CNNs), and deep-belief networks (DBNs). We are interested in CNNs because they can group certain inputs known to contribute together, e.g., logging points above the measured depth of interest in a separate group of points below, such as one would expect from field applications. Preliminary results suggest that this approach can yield more accurate interpretations that traditional ANNs. We also tested DBNs, which can identify features before the interpretation is completed (unsupervised Boltzmann machine), thereby reducing biases implicit in the training dataset.

We also test the idea of using different networks in tandem, first calculating only one property (e.g. VCL), and then using that property as an input for a network that calculates another property (e.g. PHIE), instead of using only the original inputs. For each network, we optimize its structure and hyperparameters. In our test samples, we use data from different wells across the same formation achieving 99, 90%, 85 and 70% prediction accuracy for VCL, PHIE, SW, and K, respectively.

We also tested the use of ANNs trained in a specific formation to data acquired in a different formation, but the results were poor, corroborating the specificity of ANNs to the lithology where they were trained. Nonetheless, the amount of data required to train our ANNs was relatively small (seven wells out of 60). Considering the amount of data typically required for training more general ANNs, we recommend differentiating between major lithologies and/or rock classes to keep the amount of training data (explicitly interpreted) at a minimum.

Auto-Navigation of Optimal Formation Pressure-Testing Locations by Machine-Learning Methods

Bin Dai, Christopher Jones, James Price and Anthony van Zuilekom, Halliburton

Formation pressure testing provides important information for exploration and production activities. Accurate reservoir pressure measurements are necessary to help ensure a well is drilled safely, and to identify and evaluate the potential and value of that discovery. Interpretation of pressure gradients provide the reservoir compartmentalization structure of a well, oil-gas-water fluid contacts, and can be indicative of compositional grading, as evidenced by second-order density changes. However, this is predicated that pressure testing quality be sufficient for high-resolution analysis. Unfortunately, obtaining quality data from formation testing can be difficult and prolonged. Locations initially selected for formation pretesting along the wellbore are often not optimal, and the time spent conducting pressure testing on those locations is wasted. Specifically, in this 23-well study, only 57% of the locations selected were high quality, meaning that 43% of the pressure test locations were of suboptimal quality. Further, pressure testing of the suboptimal locations takes twice as long as that of the high-quality locations. Therefore, considerable operational time savings can be realized if low-quality locations can be avoided. Further, if only the optimal locations are chosen for pressure testing, then data quality can be significantly improved for reduction of uncertainty during formation evaluation.

A multivariate machine-learning method is presented that builds a statistical correlation between the formation pressure-test quality index and conventional wireline logging data. Primarily, the model is constructed from triple-combo log data to a pressure-test quality index. The procedure begins with logging data extraction and preparation. Both conventional wireline logging data and corresponding pretest data from 20 wells in one region were obtained. Data preprocessing and missing-data estimation were conducted to help ensure the sample number of the conventional wireline logs matches the sample number of the pretest. Each well contains multiple pretest data, which results in a total of more than 1,000 samples (conventional logs and pretest pairs) for machine-leaning model development and validation. After the dataset preparation was completed, various learning algorithms were explored with an optimal learning algorithm selected to create the final model. The model was then applied to three additional case studies for independent validation including: (1) an easy pressure-testing job; (2)a typical pressure-testing job; (3) a difficult pressure-testing job, with timesavings and quality improvement shown for each. The novelty of the new machine-leaning model lies in the ability to predict the quality-index log for the formation pretest based on previous conventional wireline logging data and to guide the wireline engineer to select the locations along the wellbore at which to conduct the pretest. This method reduces the number of unsuccessful pretest locations along the wellbore from 43% on average to between 15 and 5% for the three case studies, which results in significant timesavings.

Carbonate Log-Interpretation Models Based on Machine-Learning Techniques

Wei Shao, Mahmoud Eid and Gabor Hursan, Halliburton

Carbonate lithology is known to be complex with a highly heterogeneous pore system. Primary and secondary pores commonly coexist at the same depth, which results in poor performances from the conventional carbonate log-interpretation models. The development of new log-interpretation models for carbonate formations can be a challenging and often futile process with the traditional forward modeling and inversion approach.

Machine-learning (ML) techniques provide an alternative approach to the development of carbonate log-interpretation models by learning the underlying relationships between carbonate petrophysical properties and logging measurements from core-analysis data samples. The development of carbonate log-interpretation ML models often requires "big data" to represent the complexities of formations. In practice, the big-data requirement is not easy for our industry to meet. A "smart-data" workflow has been created to develop ML models with a limited number of core-analysis data samples. This workflow is used to develop carbonate pore-typing and permeability ML models with only 200 core samples.

Several challenges, however, still remain in the application of ML models to field logging data interpretation.

- First, a large discrepancy often exists between core measurements and field logging measurements because of the differences between core-measurement conditions and field logging conditions, such as temperature and pressure. The direct application of core-data-based ML models to field data provided poor results in many cases. To address this issue, specific domain knowledge-based constraints and corrections are applied to the ML models and field data to ensure accurate performances.
- Second, the performances and validities of the ML models are only as good as the qualities and representation of the core data. ML models will fail for reservoir sections that are not represented by the core data. It is vital for logging analysts to know the application envelopes and reliabilities of the ML models.
- Third, because of the complexities of the carbonate formation, the carbonate log-interpretation ML models can be very complex. It is impossible for certain ML models to be explained and understood by log analysts, and it is difficult for log analysts to trust and accept these ML models. Consequently, ML models that can be explained are necessary for carbonate log interpretation.

The "smart-data" workflow presented in this paper is illustrated by developing a Middle East carbonate pore-typing and permeability ML model to demonstrate the application of ML models for carbonate log interpretation. The paper also discusses the approaches used to align ML models to reservoir conditions and to develop the application envelope, as well as reliability indicators and explainable ML models through feature engineering and model complexity-reduction methods.

Class-Based Machine Learning for Next-Generation Wellbore Data Processing and Interpretation

Vikas Jain, Schlumberger

While the traditional processing and interpretation workflows are subjective and inconsistent based upon the Petro Technical Expert (PTE)'s expertise, and slow in turning around the deliverables, machine learning requires a large amount of data (depth or time samples) to effectively span the measurement space and a high number of measurements to deduce low dimensional feature set. The two requirements of machine learning are not generally available, making its applications in wellbore data processing and interpretation quite limited.

We propose a novel class-based machine-learning (CBML) approach. This approach alleviates the shortcomings of machine learning by first reducing the training data (depth or time samples) into a few explainable classes, and then learning models by classes. The probabilities of new data points belonging to existing classes are computed. Each new data point is then assigned the class with the highest probability. The class-based learned model is applied and uncertainties of the results computed.

Essentially CBML acquires knowledge from the training dataset/s and propagate, if and where applicable, to new data, eliminating the need for a large training data. A new clustering algorithm and uncertainty computations enable application of the new approach to datasets with fewer measurements. CBML not only removes the subjectivity and inconsistency but also substantially improve the turnaround time from the receipt of data to the delivery of results. The approach is transformed into a continuous learning, extraction and application loop automating the processing and interpretation of wellbore data.

The class-based machine-learning approach combines the best of traditional petrophysical workflows and machine learning. It provides objective, consistent and near-instantaneous answers with minimal intervention. We weill present the "class-based machine-learning" workflow for well-data processing and interpretation, and its application and associated results on multiple use cases, such as (1) multifunction logging-while-drilling data from West Africa, (2) reservoir saturation data from the North Sea, and (3) integrated wireline logging data from Wyoming.

Domain Transfer Analysis—A Robust New Method for Petrophysical Analysis

Ravi Arkalgud, Helio Flare, Andrew McDonald, Derek Crombie and Jennifer Market, Lloyd's Register

Today, many machine-learning techniques are regularly employed in petrophysical modelling, including such methods as cluster analysis, Monte Carlo fuzzy logic, self-organizing maps, and principal component analysis. While each of these methods has its strengths and weaknesses, one of the challenges to most of the existing techniques is how to best handle the variety of dynamic ranges present in petrophysical input data. Mixing input data with logarithmic variation (such as resistivity) and linear variation (such as velocities) while effectively balancing the weight of each variable can be particularly difficult to manage effectively.

A novel method—domain transfer analysis (DTA)—has been developed which uses a nonlinear partial differential equation solver for predicting log curves, enabling more effective integration of disparate data types. DTA is conceived based on extensive research conducted in the field of CFD (computational fluid dynamics).

This paper is focused on the application of DTA to petrophysics and its fundamental distinction from various other statistical methods adopted in the industry. Case studies are shown, predicting porosity and permeability for a variety of scenarios using the DTA method, standard machine-learning methods and nonstatistical techniques. The results from the various methods are compared, and the robustness of DTA is illustrated. The example datasets are drawn from public databases within the UK and Dutch sectors of the North Sea, some of which have a rich set of input data including logs, core, and reservoir characterization from which to build a model, while others have relatively sparse data available allowing for an analysis of the effectiveness of the method when both rich and poor training data are available.

The paper concludes with recommendations on the best way to use DTA in real-time to predict porosity, permeability, saturation, TOC, mineral volumes, and brittleness from the data that are available at varying stages of the drilling and completions process.

Enhanced Reservoir Geosteering and Geomapping From Refined Models of Ultradeep LWD Resistivity Inversions Using Machine-Learning Algorithms

Hsu-Hsiang (Mark) Wu, Cindy Dong and Michael Bittar, Halliburton

Ultradeep logging-while-drilling (LWD) resistivity tools have been widely used in borehole resistivity applications, including geosteering within, geomapping of and geostopping above single or multiple reservoirs. Previous field examples of the ultradeep-reading tools successfully demonstrated a detection range of more than 200 ft away from a wellbore. As a result of this capability, the complexity of the inversion process increases to accommodate a greater number of layered models, as compared to conventional approaches. Cloud-based distributed solutions were implemented in the algorithms to efficiently provide in-time geological inverted models for real-time decisions. The cloud-based parallelization platform and available field data of the ultradeep-reading tools initialized and enabled further studies and evaluations of the advanced machine-learning algorithms applied into the existing inversion process.

This paper presents several deep-learning algorithms to statistically evaluate many inverted solutions from the ultradeep resistivity measurements. The proposed methods identify the most likely distributions to remove outlier signals and models to produce a more geologically reasonable representation. The proposed methods additionally offer automatic boundary picking of layers, with a major resistivity contrast between two layers. The determined geological connections between the measurements and the inverted solution distributions learned from the past sets of measurements are used to train any future inversion process on a new set of measurements, enabling more efficient evaluations and calculations. Several modeling and field examples establish better geological interpolations acquired from the presented machine-learning algorithms than the original inversion approach. The use of these machine-learning concepts improves the quality of the final geological interpretation and further reduces the overall computation time, resulting in a processing speed that is twice as fast as the existing inversion approach.

Estimation of Dynamic Petrophysical Properties From Multiple Well Logs Using Machine Learning and Unsupervised Rock Classification

Mohamed Bennis and Carlos Torres-Verdín, The University of Texas at Austin

The process of mud-filtrate invasion gives indirect information about the dynamic petrophysical properties of reservoir rocks, which are essential to predict ultimate hydrocarbon recovery and to optimally design primary and/or enhanced recovery procedures.

We focus on the interpretation of conventional well logs, such as density, neutron porosity, and apparent resistivity, to estimate dynamic properties of rocks, such as permeability, relative permeability and capillary pressure, using a machine-learning (ML) algorithm. The inversion problem is mathematically posed as a minimization of a cost function. There exist various approaches to solve this problem, such as gradient-based and statistical methods. However, these methods can be computationally expensive, and the process needs to be repeated for each new set of measurements. In this study, we investigate ML methods to automatically detect and extract complex features present in the training dataset.

The dataset is synthetically generated using fast numerical simulations implemented in 3D UTAPWeLS (The University of Texas at Austin Petrophysical and Well-Log Simulator). We assume a vertical well, horizontal layers, and an axial symmetric invasion. Dynamic petrophysical properties of layers are randomly generated using biased distributions. We simulate the process of mud-filtrate invasion and obtain the radial distribution of water saturation and salt concentration. The corresponding well logs, such as density, neutron porosity, and apparent resistivity, are then numerically simulated to reproduce the available well logs. This process is repeated until thousands of examples are generated to serve as a database using parallel computations. We divide the dataset into three disjoint subsets denoted as training, validation, and test. Given the training and test sets, we compare the performance of different multi-output regression techniques such as decision trees, random forest, and neural networks. Next, we verify the accuracy of our approximation on the validation dataset. If the accuracy is insufficient, we build a new enhanced ML model to reduce the error. The performance of the ML model is optimized through the adjustment of the learning rate or by adding or removing features. New features are incorporated such as the ratio of deep and shallow resistivity logs and the average of neutron porosity and density porosity logs.

Several field and synthetic examples describe the successful application of the methods on the estimation of dynamic petrophysical properties of gas- and oil-bearing rocks invaded with water-based mud and water-bearing rocks invaded with oil-based mud. The estimated dynamic petrophysical parameters are then used as an input for unsupervised rock classification using hierarchical clustering. Rock classification results show a good agreement with geological facies.

Using ML models, we build an approximation to the inversion function offline. Then, this function can be rapidly evaluated for real-time inversion of well logs across many wells in the same hydrocarbon field. The application of the ML algorithm requires some prior knowledge of drilling-mud properties, and for each mud configuration, we are required to train a new ML model.

Investigating How Logging Data Precision and Accuracy Degradation Impacts Machine Learning

Jeffrey L. Baldwin, Lehne George and Alexander Klebanov, Chesapeake Energy

Logging tools measure formation properties that are indirectly related to density, resistivity, etc. The quality (precision and accuracy) of such measurements will degrade due to a number of physics-related, environmental, operational, and tool design factors. Perturbations of logging tool measurement precision and accuracy are very much situation dependent and time/circumstance variant. Inferences about formation properties such as density, resistivity, etc., based on well-logging measurements likewise may suffer degradation in quality and utility when log-data precision and accuracy decline. Yet most of the O&G industry approaches log data with assumptions about log-data quality that are overly optimistic. Sometimes, log-data quality issues are even ignored when those data are used during various processing actions that lead to estimation of formation characteristics such as porosity, saturation, etc.

Machine-learning, like any other computer-processing methodology, is not immune to deleterious log-data precision and accuracy-degradation effects. And like other computer-processing methodologies machine-learning data-evaluation methods must be able in some manner to “sense” and respond appropriately to log-data-quality degradation. Classical methods use, for example, “if-then-else” rules to correct low-quality and erroneous log data. Machine-learning methods must be explicitly exposed to aspects of log-data quality, both high and low, that eventually impact the veracity of log-data processing outputs before these methods can “learn” to recognize and possibly deal with unwanted log-data variance.

This paper examines some simple logging-tool data-variance factors and evaluates how changes in log-data precision and accuracy impacts machine-learning processes under various simplified operational scenarios. It is shown that (1) decline in log-data precision affects machine-learning algorithms in similar ways as are experienced by classical data-processing methods and techniques, (2) exposure of machine-learning algorithms to an abundance of log data does not always result in more precise estimates of, for example, porosity, saturation, etc., and (3) that including examples of poor-quality log data in a machine-learning training set can have a positive impact on the quality of processing results.

Leveraging Probabilistic Multivariate-Clustering Analyses of Well Logs to Identify “Sweet Spot” Intervals in Heterogeneous Conventional and Unconventional Reservoirs

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The results of a multiwell Bayesian-based probabilistic multivariate clustering analysis (PMVCA) with a built-in prediction subroutine can be leveraged to rapidly identify “sweet spot” Intervals in well profiles that satisfy a set of user-defined cutoff criteria. Usually, the primary goals are to generate total porosity (*Por*) and total water saturation (S_w) profiles within the Intervals. Secondary goals might be to determine Interval thicknesses plus total organic carbon (*TOC*) and brittleness index (*BI*) profiles. The method works well for both conventional and nonconventional reservoirs. The required input data is standard triple-combo well logs, although more credible results can often be obtained when whole-core plug data, such as grain density (*GD*) and kerogen (via *TOC*), are available. The workflow begins with a PMVCA using well logs (after well-log QC, including curve normalization, and rigorous core-to-log depth correction when core data are available).

The thickness plus the average and standard deviation of *Por* of each Interval are determined using a modified density-porosity (*DPHI*) equation. A modified *DPHI* equation is one in which *GD* can vary with each sample (digitized depth step). Such profiles are generated by leveraging the MVCA probabilistic assignments of each sample to the several electroclasses (rock types) that comprise the PMVCA suite. The analyst has the role of assigning *GD*s to the different endmember electroclasses (e.g., 2.65 g/cm^3 to Ss, 2.71 g/cm^3 to Ls, etc.). An alternative approach for determining *GD* exists if at least one well involved in the multiwell PMVCA has sufficient and credible plug *GD* analyses. Then, a complete *GD* profile can be generated for not only the cored well, but also each noncored well if *GD* from the cored well is included as a clustering variable in the PMVCA.

In an analogous manner, S_w profiles within each Interval can be generated using a modified Archie equation, where "modified" means that the *a*, *m*, and *n* constants can vary with sample in the same probabilistic manner if different *a*, *m*, and *n* values are assigned to different electroclasses. In conventional reservoirs where wet zones might exist, a Pickett plot linked to the PMVCA electroclass results can assist with determination of R_w and Archie *m* for different but closely associated electroclasses.

Crucial to the use of the PMVCA probabilities in the computation of *Por* and S_w is the development of a realistic PMVCA. Two options exist for initialization of a PMVCA: supervised and unsupervised. Supervised clustering initialization (training) using a core description ideally results in better modeling of lithofacies in noncored wells, but relative success depends on a "purposed" core description and also on the ability to ignore samples adjacent to bed contacts. Due to data and logistics constraints, unsupervised initialization is more common. With this method, training can be done using all valid data when using a model-based clustering engine that has a neural aspect. Using multiple runs (realizations) combined with selected convergence criteria assist with identifying the "best" solution.

Quantitative Interpretation of Oil-Based Mud Microresistivity Imager via Artificial Neural Networks

Zikri Bayraktar, Dzevat Omeragic and Yong-Hua Chen, Schlumberger-Doll Research

The new generation of oil-based mud (OBM) microresistivity imagers provides photorealistic high-resolution quantified formation imaging. Currently, interpretation is based on composite processing providing an apparent-resistivity image that is largely free of the standoff effect. The inversion-based workflow is an alternative for quantitative interpretation, providing higher-quality resistivity-image button standoff, and formation permittivities at two frequencies. An artificial neural-network (NN)–based workflow is developed for quantitative interpretation of OBM-imager data as an alternative to the inversion-based workflow.

The machine-learning (ML) approach aims to achieve at least the inversion-level quality of formation resistivity, permittivity, and standoff images but an order of magnitude faster, making it suitable for implementation on automated interpretation services and integration with other ML-based algorithms. The major challenge is the underdetermined problem because the OBM imager provides only four measurements per button whereas eight model parameters related to the formation, mud properties, and standoff need to be predicted. The corresponding nonlinear regression problem was extensively studied to determine tool sensitivities and the combination of inputs required to predict each unknown parameter most accurately and robustly. This study led to the design of cascaded feed-forward NN, where one or more parameters are predicted at each stage and then passed on to following steps as inputs until all unknowns are accurately predicted.

Both inverted field datasets and synthetic data from finite element method (FEM) modeling of tool responses were used in multiple training scenarios. In the first strategy, field data from a few buttons and existing inversion results were used to train NN and reproduce standoff and resistivity images for all the buttons. Although the generated images are comparable with images from inversion, the method is dependent on the availability of field data for variable mud properties, which currently limits the generalization of the NN to diverse mud and formation properties.

In the second strategy, we used the synthetic responses from a finite-element EM simulator for a range of standoffs and formation and mud properties to develop a cascaded workflow, where each stage predicted one or more model parameters. Early stages of the workflow predicted the mud properties from low-formation-resistivity data sections. NNs then fed the estimated mud angle and permittivities at two frequencies into next stages of the workflow to finally predict standoff and formation resistivity and permittivity. Knowledge of measurement sensitivities was critical to design efficient parameterization and robust cascaded NN not only due to the underdetermined nature of the problem but also the wide dynamic range of mud and formation properties variation and the measurements. Results for processed resistivity, standoff, and permittivity images will be presented, demonstrating very good agreement and consistency with inversion-generated images and other available measurements, such as wireline induction, dielectric logs, and ultrasonic images. Combination of the two strategies, training on both synthetic and field data, will lead to further improvement in robustness and allow customized interpretation applications for specific formations, muds, or applications.

Role of Machine Learning in Building Models for Gas-Saturation Prediction

Yagna Deepika Oruganti, Peng Yuan, Feyzi Inanc and Yavuz Kadioglu, Baker Hughes, A GE Company

Quantitative gas-saturation determination for reservoir monitoring purposes became possible with the introduction of a new-generation of multidetector pulsed-neutron tools and interpretation algorithms. One distinctive feature of these interpretation algorithms is that they rely heavily on modeling of tool responses for the given

completions and fluid types present in the system. This modeling is usually achieved through nuclear Monte Carlo simulations and involves long computing times, significant computer resources, and human intervention. However, despite the time and cost drawbacks of this approach, an associated benefit is the ever-growing library of models being computed for wells with different attributes. The existence of such Monte Carlo-computed model libraries lends themselves to deployment of machine learning to substitute the lengthy and expensive Monte Carlo-based model-building process. As a result, cost and time management cease to be an issue in the gas-saturation determination.

Machine learning is a subbranch of artificial intelligence, and encompasses a category of statistical algorithms that can “learn” from existing data without explicit programming. These algorithms can be used to build models to predict the outcome for a given set of conditions. In this specific instance, the conditions are completion, formation, and fluid parameters. For example, borehole size, number of casing strings, presence of cement, annular-fluid parameters, lithology, porosity and fluid types in the pore space are all needed to predict the response of a tool designed for reservoir monitoring. The ratio of inelastic gate count rates from the short and extra-long space detectors and ratio of thermal-gate count rates are usually the outcomes from a Monte Carlo modeling exercise. The machine-learning activity is a substitute for this process, providing fast and accurate inelastic and thermal-gate ratio values for gas-saturation estimation. Various machine-learning algorithms, such as random forest and extreme gradient boosting, were applied to the data to generate prediction models for the ratios mentioned above. Results showed that over 90% accuracy can be achieved between the predictions from the machine-learning models and the ratios calculated from the Monte Carlo simulations on a validation dataset.

In this paper, the Monte Carlo-based model-building process and the existing model libraries used in quantitative gas-saturation analysis will first be discussed, along with the data-processing methodology used to generate input data for the machine-learning algorithms. Following that, various machine-learning models applied to the nuclear data and their prediction accuracies along with variable values will be discussed. Next, the trained machine-learning models will be deployed on blind test datasets (that the model has never encountered before), and the performance of the models on these completely new datasets will be demonstrated by comparing the predictions with those of the Monte Carlo–based models. Finally, the success of the trained machine-learning model will be demonstrated by deploying it on an actual gas-saturation log, thereby showcasing the time and cost benefits of having data-driven models that can accurately predict inelastic and thermal gate ratio values.

The Use of Machine Learning to Predict a Permeability Model From NMR Logs: An Example of Presalt Carbonates of Santos Basin

Laura Louise Demarch, George Correa de Araujo and Alexandre Campane Vidal, Unicamp

Permeability models in highly heterogeneous carbonates are a current challenge, given their complexity in both lithology and porous system, NMR logging has emerged as one of the advanced technologies for in-situ reservoir evaluation, being able to capture important formation properties that the classical logs have no sensitivity to, such as permeability and fluid characterization. To estimate permeability from NMR logs, the Timur-Coates and Schlumberger-Doll-Research (SDR) are the most used models; however, it has been proved to be limited, especially in the highly heterogeneous Presalt reservoirs of Santos and Campos Basins, Brazil. One of the main problems is that a single T_2 cutoff may not encompass the whole interval heterogeneity, which means that an adjustable cutoff would be more appropriate especially in carbonates with high geological variation.

To solve that problem, we combined NMR T_2 log spectra with core permeabilities, and multilayer perceptron neural networks to improve the permeability models of two wells from Santos Basin, belonging to the Itapema (Well 1) and Barra Velha (Well 2) Formations. We compared our approach to standard and adjusted Timur-Coates and SDR models, with different degrees of heterogeneity, and a range of permeability from over 3,000 to 0.001 mD.

For the model of Well 1, a fairly heterogeneous limestone, a solely three-layer neural network allowed a convergence to an improved permeability model in comparison to the previously mentioned literature models. On the other hand, the model for Well 2 did not converge with the same criteria of the first well due to its even greater vertical heterogeneity, resulting in a more difficult learning process for the neural network. In order to improve the results of this well, we used more advanced techniques, such as using more hidden layers, normalization, different initializations, grid search, data augmentation and other types of pretrained networks.

Our approach enabled the permeability model to be performed without the T_2 cutoffs, which eliminates part of the uncertainty and also decreases the expenditure on NMR laboratory measurements, although the core permeability measurements are still necessary for calibration, they are a much cheaper and simpler analysis. In addition, the results obtained with the proposed model were closer to the permeability core measurements, improving the estimation of NMR log permeability for the studied intervals.

Using a Physics-Driven Deep Neural Network to Solve Inverse Problems for LWD Azimuthal Resistivity Measurements

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Characterizing the subsurface structure through indirect measurements is a central task in well logging. Although many methods have been developed for solving such an inverse problem, it is still a challenging topic to keep up with the demanding requirements from the industry with regard to the accuracy and computational efficiency. Crowned with huge success in computer vision, speech recognition, and many other domains, using deep learning to solve well-logging-related inverse problems has yet to be exploited. Nonetheless, physics-driven deep learning is opening up new research directions for the inverse problem.

In this study, we propose a novel physics-driven deep neural network to solve the inverse problem for LWD deep azimuthal resistivity measurements, whose applications include but not limited to well placement, reservoir mapping, geostopping, landing fault detection, and salt edge detection, etc. Traditionally, inversion and interpretation of LWD azimuthal resistivity logging measurements are conducted on the surface. Due to the extremely low data rate of the borehole telemetry, only a small portion of logging curves can be sent to surface to reconstruct underground formation in real time. The majority of LWD curves, although containing rich subsurface information, are stored in downhole memory and can only contribute to post-job analysis after the LWD tool is retrieved from downhole. Performing inversion directly in the downhole environments can circumvent the low-data-rate issue of telemetry and exploit all logging curves in real time. However, the state-of-the-art downhole computer is still incapable of carrying out inversion programs due to the very limited computational resources, no matter the inversion is based on look-up tables (requiring large downhole memory) or optimization (e.g., Levenberg–Marquardt algorithm or Markov-chain Monte Carlo methods, both are computationally intensive).

Leveraged by the forward physical model, the deep neural network designed for this study is trained with a loss function that accommodates both the model misfit and data misfit. Unlike other methods that rely on iterative procedures. The forward pass of the network is fast, computationally inexpensive and requires far less storage space than the lookup table. The deep neural network is not sensitive to the selection of initial values and provides more reliable solutions to the inverse problem with improved performance. Our case studies conclude that the physics-driven deep-learning network can deliver real-time inversion result for the LWD deep azimuthal resistivity tool with high accuracy and much-relaxed hardware restraints.

NEW BOREHOLE LOGGING TECHNOLOGY

A Concept Platform for Highly Efficient and Accurate Pressure, Sampling and Sidewall Coring Operations Using Wireline Conveyance

German Garcia, Hadrien Dumont, Vinay K. Mishra, Li Chen, Christopher Babin and Ron Hayden, Schlumberger

A concept platform integrating the precise movement of a linear or azimuthal actuator, such as in instrumented wireline intervention tools (IWIT), with fast pressure measurements or fluid/rock sampling instruments is presented. This device accurately moves the measurement probe or sampling assembly either in the longitudinal or azimuthal direction in the wellbore to significantly improve operational efficiency and data quality.

Precise downhole movement control enables the collection of pressure data or rock/fluid samples at exact depth increments, hence eliminating errors induced by cable stretching, overpull, or variable cable creep. Specific lithofacies could be targeted from a borehole-image log combined in the platform. Simulation with current IWIT capabilities shows significantly reduced uncertainty over common wireline protocols. The operational procedure includes correlation using standard wireline gamma-ray methods, then the platform is anchored at the top of the interval of interest and the linear actuator is used for probe displacements. Inchworm movements can also be performed to extend the length of the probe displacements. Removing cable movement for probe displacements significantly reduces the biggest source of error in distributed pressure measurements. Similar approach is proposed for the coring tool with the added benefit of being able to rotate the drilling bit at different azimuths to collect rock samples.

This concept platform would reduce the time spent on pressure surveys if similar accuracy to current practices is acceptable. Because the biggest remaining source of error is gauge accuracy, simulation results show that fewer stations are needed to replicate standard wireline results. Where accuracy is important, as with pressure measurements to quantify reserves using gradient intersection to define fluid contacts or validate compositional fluid gradients, the proposed approach is shown to significantly reduce error using an equal number of stations. We use datasets from previous work to show the impact of the error reduction in the position of fluid contacts.

IWITs currently used in cased hole employ active anchoring to perform intervention tasks. Applications of linear actuators in casedhole operations today include pulling and pushing movements to manipulate completion components. The controlled downhole force available for these operations goes up to 80,000 lbf while the anchoring force could be up to 150,000 lbf. In the proposed concept platform, this pulling force could be instrumental in cases with elevated risk of differential sticking. By anchoring the upper part of the platform in overlying impermeable intervals, only the pressure probe or rock/fluid sampling assembly is lowered into the permeable interval to conduct the operation without exposing the full length of the string to the pressure differential forces and hence, mitigating the risk of sticking.

The proposed architecture for the concept platform combines several operational elements used today as separate entities in wireline operations. Their integration, however, generates important efficiency gains, reduces risk in pressure measurements and fluid sampling and sidewall-coring operations, improves accuracy, and enables the implementation of unprecedented distributed pressure measurements and coring practices with azimuthal positioning capabilities using wireline.

A Fast Bayesian Inversion Method for the Generalized Petrophysical and Compositional Interpretation of Multiple Well Logs With Uncertainty Quantification

Tianqi Deng, Joaquin Ambia-Garrido and Carlos Torres-Verdín, University of Texas at Austin

Resistivity, nuclear properties, and acoustic slowness measured by logging tools can be affected by several factors specific to the design of the tool. Shoulder-bed effects, polarization horns, and mud-filtrate invasion are just a few examples of abnormal measurement effects. Fast forward modeling of well logs and inversion algorithms can be used to take these effects into account and enhance the resolution of well logs. The sharpened well logs reveal true formation properties, and are thus more reliable for estimating hydrocarbon in place and multiwell correlation. Gradient-based inversion can yield acceptable results; however, the calculation of derivatives is difficult without explicit information of the tool properties. Bayesian methods can also be useful, but they are computationally expensive, requiring ~10,000 times of forward simulations, which translates into hours if not days, whereby its expedient application to field data becomes impractical.

We developed a new general Bayesian method for well-log (petrophysical and compositional) inversion by combining a perturbed Gauss-Newton algorithm with Markov-chain Monte Carlo (MCMC) sampling. First, we estimate layer-by-layer properties using a perturbed Gauss-Newton algorithm and by approximating derivatives by the difference between the target field log and a simulated log. This gradient-based procedure reduces burn-in time and increases acceptance rate of the MCMC sampler by improving both initial guess and proposal distribution. Next, we implement a parallel MCMC sampler to refine the solution and quantify uncertainty. Finally, the layer-by-layer properties and their uncertainty are used to estimate petrophysical and compositional properties.

We verify and benchmark the applicability of our method in the inversion of gamma ray, resistivity, density, PEF, neutron migration length, and acoustic slowness with field data from various vintage vendors acquired across clastic, carbonate, and unconventional sedimentary sequences. Results indicate that in vertical wells with layers greater than 2 ft, the new inversion method converges in minutes, requiring less than 10 runs of forward modeling with a relative error below 10%. For thin layers (<2 ft), the computational time can be reduced by more than a factor of two compared to conventional MCMC methods. We also describe synthetic examples where we emphasize the significance of uncertainty quantification: the standard deviation of inverted resistivity can be as high as 100% for a 5% log-normally distributed measurement noise.

More importantly, the new Bayesian inversion method enables the fast and accurate estimation of petrophysical and compositional (fluid and matrix) properties of rocks with uncertainty quantification from the previously estimated layer-by-layer properties. It allows the implementation of user-defined correlations among solid components and mineral groups. In the case of shaly sandstones, for instance, it allows automatic detection and estimation of petrophysical and compositional properties for the cases of laminated or dispersed shale systems. In addition to its speed, robustness, and reliability, the Bayesian inversion method provides great flexibility to include user-defined interpretation constraints and can perform rock-class dependent detection and interpretation with minimum user intervention, thereby successfully competing with commercial solvers.

A New Multifrequency Array Dielectric Logging Service: Tool Physics, Field Testing, and Case Studies in the Permian Basin Wolfcamp Shale

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A new wireline multifrequency, multispacing dielectric logging service has been developed.

The service is based on the performance of a new multiarray electromagnetic propagation instrument operating in a frequency range from tens of megahertz up to one gigahertz. The sensor section has been built on an articulated pad that is firmly pressed against borehole wall, even in enlarged or rugose borehole conditions. The array scheme uses four 1-in. spaced receivers with three pairs of transmitters placed symmetrically above and below. Each array transmitter and receiver antenna operates as a magnetic dipole with orientation along the borehole longitudinal axis. The instrument provides borehole-compensated propagation-wave attenuation and phase difference measurements at five discrete frequencies at multiple depths of investigation (up to 8 in.).

The instrument operating principles are described in detail. The tool calibration, depth of investigation and vertical resolution are discussed in conjunction with modeled synthetic responses. Measurement results are presented from the laboratory environment as well as from a test well near Austin (Texas).

A two-step inversion algorithm has been implemented to process the raw acquired data. First, the “EM Inversion” module uses numerical forward modeling to convert calibrated attenuation and phase-difference measurements to borehole-corrected apparent formation resistivity and permittivity values. Next, a second inversion module applies one of the several workflows to produce petrophysical deliverables including flushed-zone resistivity, water-filled porosity, water salinity and rock textural parameters.

The instrument response and petrophysical results will be discussed in detail using examples from a well drilled in the Permian Basin Wolfcamp formation, in Texas, and having two contrasting borehole environments (oil- and water-based mud systems), both very challenging for dielectric data acquisition and interpretation. Dielectric inversion, for water-filled porosity and pore connectivity are complemented with nuclear magnetic resonance (NMR) log data to further understand fluid types and bound versus moveable fluid fractions.

A New Through-Casing Acoustic Logging Tool Using Dual-Source Transmitters

Xiaoming Tang, China University of Petroleum (East)

A new acoustic tool has been developed to measure formation acoustic properties through casing. This measurement is important for oil and gas production in mature fields, and for wells that are cased without logging due to stability issues. In the past, conventional acoustic logging through casing in poorly bonded boreholes has been a difficult task because the acoustic data are contaminated by the overwhelming casing signal that masks the formation acoustic signal. To overcome the difficulty, we developed an acoustic tool using dual-source transmitters and the processing technique for the data acquired by the tool. This paper elaborates the operation principle of the new dual-source technology and demonstrates its application to casedhole acoustic logging. By using the dual-source design, the overwhelming casing waves from the poorly bonded casing are largely suppressed and the formation acoustic waves are significantly enhanced in the data acquisition process. Subsequent processing of the data reliably obtains acoustic velocity of the formation. The new tool has been tested in many cased wells. The resulting acoustic velocity profile agrees well with its openhole counterpart for various cement-bond conditions. The success of this technology makes casedhole acoustic logging an effective operation that can be routinely used to obtain reliable formation information through casing.

Accurately Estimating Shear Slowness Using Data-Driven Quadrupole Sonic Logging-While-Drilling Data Processing

Ruijia Wang and Richard Coates, Halliburton

Sonic logging data are useful in a variety of applications, including seismic correlation, rock mechanics and wellbore stability, pore pressure prediction, sourceless porosity estimation, gas detection, and stress and fracture characterization. In many cases, logging-while-drilling (LWD) sonic logs provide an attractive alternative to those acquired on wireline because of hazard avoidance, timeliness of information, rig costs, or ease of deployment, particularly in horizontal wells. Shear-wave slowness logs play an important role in many applications, yet they can be problematic to obtain, particularly in slow formations where the refracted shear-wave arrival is not supported. Modern LWD sonic logging tools typically use a quadrupole excitation source that can excite a quadrupole mode, or screw waves, from which the formation shear-wave velocity can be derived.

A fundamental feature of screw waves excited by a quadrupole source in an LWD environment is that their cutoff frequency slowness approaches the true formation shear slowness. However, the slowness data near the cutoff frequency are often influenced by noise or the presence of other modes because of its low excitation amplitude of the screw wave. Conventional methods process this energetic, higher-frequency portion of the screw waves and perform a model-based dispersion correction to obtain the final shear slowness estimate. This model-based correction assumes a well-conditioned borehole and known borehole (e.g., caliper and mud speed) and formation parameters (e.g., density and compressional speed) and may produce erroneous results when assumptions are violated.

To overcome these difficulties, a data-driven quadrupole method was developed that operates in the frequency domain and uses all useful dispersion responses of the existing modes. The technique is an extension of the data-driven dispersion processing of the wireline flexural waves for quadrupole data. The process first generates a differentiate-phase frequency-slowness coherence/semblance map and then extracts the slowness dispersion vs. frequency, which is used to compute the slowness density log along the slowness axis. An edge-detection method is then applied to capture the leading edge associated with the shear-slowness low-frequency asymptote and to form an initial estimate of the formation shear slowness based on slowness value at the leading peak on the slowness density log. This shear slowness forms the input to another algorithm that minimizes the misfit between the screw slowness vector and a simplified screw-wave dispersion model to refine the shear-slowness answer. The simplified screw-wave dispersion model consists of a precomputed library of theoretical screw-wave dispersion curves and two data-driven parameters that are used to account for errors generated by unknown inputs. The optimization process estimates both the shear slowness and screw-wave dispersion response. Because the new inversion uses signals of all reliable frequencies, the technique is sufficiently accurate, stable, and efficient to meet both real-time and post-processing requirements.

Field data results suggesting that reliable and high-quality shear-slowness logs can be obtained over a wide-range of formations are discussed.

Advanced LWD OBM Imaging in Challenging Subsalt Deepwater Environments

Gerardo Cedillo and Dann Halverson, BP GoM; Carlos Maeso, David Maggs and Hathairat Watcharophat, Schlumberger

Deepwater depositional environments in the Gulf of Mexico can be very complex. Accurate determination of depositional facies is important in these very capital-intensive fields. The most common facies are laterally extensive sheet sandstones with thin shale layers, channel complexes (can be isolated or amalgamated) and channel-levee complexes (with poor reservoir communication). Steep dips close to salt domes and the presence of potential fluid conduits due to faults or fractures are also important to identify. Determining the character of the sediments requires borehole imaging. Interpretation of the images is used to improve the net-sand calculations, understand the geology in the near-wellbore region (both in structure and depositional environment) and provide valuable geomechanics information to determine the stress vector.

A recent well was drilled through one of these deepwater sediment sequences in the Gulf of Mexico with an oil-based mud system. An extensive acquisition program included a series of LWD and wireline images. Additional to the current LWD lower-resolution borehole imaging offers, a revolutionary LWD dual physics oil-based mud imager was deployed for the first time in this field. Five different types of physics were acquired, these comprised lower-resolution images from nuclear measurements (gamma ray, density and photoelectric) and the high-resolution images from the dual-physics oil-based mud imager (resistivity and ultrasonic). Wireline resistivity images were logged as well with a high-resolution oil-based mud imager.

Comparisons of the types of features observed on the various imaging tools are made, showing how the differences in physics, resolution and time of logging affects the images and the impact this can have on subsequent interpretations. Four main categories of features are included; sand-rich sections, consistent dip shales, chaotic zones and fractures / faults. All the different images allow interpretation of the sequence. In general, the higher the resolution, the more detailed and confident the interpretation is, where the hole conditions are good. In degraded borehole sections, the early time of LWD acquisition is beneficial. The impact of the differences in the physics depends on the properties and contrasts being imaged. This is observed with fractures—with both conductive and resistive examples seen on both LWD and wireline images. The ultrasonic images are clearly complimentary, with both low- and high-amplitude fractures seen, providing more confidence in the fracture interpretation.

In an upcoming well in this field, a similar section is planned to include the new generation LWD OBM imaging suite with real-time capability. In this case real-time LWD OBM images are planned, which will allow early-time image interpretation of net, structure and geomechanics information. It will also provide an opportunity to compare the real-time images with the memory images for this suite of tools.

Can the Evaluation Accuracy of Elemental Concentration be Further Enhanced in Geochemical Logging? A Break Attempt to Obtain Purer Inelastic Gamma Spectrum

Chao Yuan, Chaoliu Li and Cancan Zhou, PetroChina Research Institute of Petroleum Exploration and Development

Over several decades geochemical logging was introduced to determine formation composition several. The newer generation of such instruments adopts a pulsed-neutron generator (PNG) and one or multiple gamma-ray detectors. The energetic neutrons are emitted from the PNG and react with the surrounding formation. During all possible neutron reactions, neutron capture and inelastic scattering generate element-dependent characteristic gammas, which are then recorded by the gamma detector for elemental analysis. The concentrations of Si, Ca, S, Fe, etc., can be determined from the capture gamma spectrum, while that of C and Mg can only be determined by analyzing the inelastic spectrum, due to their low capture cross sections, which raises the importance of the inelastic gamma spectrum. The geochemical instruments using PNG all use time gates to measure gamma rays generated in different periods after a burst of neutrons are emitted. Due to the restrictions imposed by nuclear physics, although it is possible to measure a spectrum with virtually only capture gammas, the measured energy spectrum containing the inelastic gamma contribution, called a 'burst spectrum', inevitably also contains a certain amount of capture gamma rays. The effect of capture reaction on the recorded burst gamma spectrum must be eliminated in order to derive accurate concentrations of carbon and magnesium. The present techniques include the fixed-coefficient method and hydrogen-peak reference method, in which the capture gamma spectrum multiplied a coefficient is subtracted from the recorded burst gamma spectrum. The drawback of these methods is that the fixed coefficient is used for the whole spectrum, which is not appropriate because capture gamma rays have different contributions to different ranges of the burst gamma spectrum.

In this paper, an improved method is developed to obtain a highly accurate inelastic gamma spectrum with the minimum effect of capture gamma rays. Different coefficients are used in different ranges of the burst gamma spectrum to eliminate the effect of capture gamma rays. Based on the energies of characteristic capture gamma rays of different elements, the recorded spectrum in the tight sandstone and shale formation is divided into six ranges. Furthermore, a new parameter, referred to as the deduction coefficient spectrum, is introduced and is defined as the difference between the burst spectrum and inelastic spectrum, divided by the capture gamma spectrum. The Monte Carlo method is employed to calculate the deduction-coefficient spectrum of different formation models. With the aid of the deduction-coefficient spectrum, the coefficients of six ranges can be determined in different formation models. Moreover, additional formation models are set up to evaluate the accuracy of this method. The sample variance and Pearson correlation coefficient proved that the processed inelastic gamma spectrum is highly consistent with the theoretical pure spectrum. Finally, this method is applied to field data and validated against the analysis results of core samples, which proves the feasibility of the new method.

Deducting Dispersive Permittivity From LWD Resistivity Measurements

Stein Ottar Stalheim, Equinor

Electrical permittivity *(ε)* of rock has been measured and applied in petrophysical evaluation for decades. With the new-generation tools the popularity and application of *ε* has increased in the past years. One of the revolutionary advances of the new-generation tools is the measurement of *ε* at multiple frequencies *(f)*, also known as the dispersive permittivity *(ε(f)).* Drawbacks with these tools are that they respond to the invaded zone, it is expensive data, and the data must be acquired on wire-line and therefore is not always accessible.

The thesis of this work is "information about *ε* and *ε*(f) can be extracted from multifrequency amplitude and phase-resistivity measurements," e.g, logging-while-drilling (LWD) resistivity. It is the amplitude decay and the phase shift that are measured. The amplitude decay and the phase shift are converted to the amplitude and phase resistivity by data processing, including a couple of corrections (skin correction, borehole correction) and empirically based assumption about the apparent electrical permittivity of the rock. The amplitude decay and the phase shift respond differently to the electrical rock properties (resistivity, permittivity and permeability). The characteristic of the amplitude decay and the phase shift can therefore under given conditions be used to extract both the electrical permittivity and the resistivity from the measurements.

The goal with this paper is to show that electrical permittivity and its dispersion can be extracted from LWD resistivities. The work is motivated by the fact that information about *ε* and *ε(f*) is hidden in the LWD resistivities, so why not extract it and use it? The permittivity data do not cost anything and can be used in the petrophysical evaluation, they are acquired in real time and can be used to identify bypassed zones, as geological markers and for geosteering. The LWD resistivity accuracy will also be improved by replacing the empirically based assumption about *ε* with the more correct value on *ε* in the LWD processing. This improvement in accuracy of the LWD resistivity will be significant in rocks with large permittivity (e.g. organic-rich source rock).

This paper includes the mathematics that shows how to extract permittivity from LWD resistivity and contain examples that illustrate results on data from different LWD vendor. The examples show that the LWD permittivity and its dispersion fit extremely well with data from commercial wireline tools. Limitations of present techniques

and further application of the LWD permittivity and dispersion will be discussed.

Direct MID-IR Optical Measurement of Synthetic Drilling-Fluid Filtrate Contamination During Formation-Tester Pumpouts

Ralph Piazza, Alexandre Vieira and Luiz Alexandre Sacorague, Petrobras; Christopher Jones, Bin Dai, Megan Pearl and Helen Aguiar, Halliburton

Laboratory analysis of formation-tester samples provides critical information for exploration and production activities. The physical properties, chemical properties, and composition of samples are used to confirm and resolve reservoir architecture questions, including compartmentalization and compositional grading, which is then used to design completion and production strategies. The laboratory data are used to calibrate equation-of-state models employed in reservoir simulations to project the lifetime recovery of an asset under different scenarios. This in turn yields both an optimal production strategy and reduced capital expenditure costs for a project. Furthermore, the data are used to identify flow-assurance problems and to estimate the operational costs of production. Lastly, the data provide crude value, as required, to book reserves. However, these benefits are predicated on the requirement that samples be representative of the actual formation fluid. In this aspect, contamination of samples with near-wellbore drilling-fluid filtrate remains the most common reason that samples are not fit-for-purpose. Therefore, contamination estimation must be improved.

The ubiquitous real-time downhole-contamination-estimation procedure for filtrate in petroleum uses pumpout trend-fitting. The trend-fitting attempts to regress a model to a change in the formation-tester sensor data during a pumpout in which fluid grades from filtrate to formation fluid. Sensor responses of the pure filtrate or formation fluid endmembers are estimated and the contamination calculated. When contamination is deemed sufficiently low, the sample is captured and shipped to a surface laboratory. Because sampling is often the last activity before cementing a section of well, there is not a second sampling opportunity if the laboratory determines the sample is not fit-for-purpose. Too often, the contamination estimate does not match the laboratory results due to the breakdown of three key trend-fitting assumptions (1) that the model is sufficient to describe reservoir complexity, 2) that the model can be extrapolated to determine endmember responses, and 3) that the asymptote of the pumpout is not falsely representing steady-state contamination.

Improvement in current methods of contamination estimation are nearly all driven by improving trend-fitting to existing sensor data as opposed to the development of new sensors. This work, however, describes the development of a new direct contamination sensor, designed to detect synthetic drilling fluid using optical measurements. Nearly all synthetic drilling fluids contain olefins, which are unsaturated hydrocarbons not naturally present in geologic formations. These compounds look like other petroleum hydrocarbons in the conventional visible and near-infrared optical ranges of existing wireline tools. However, in the mid-infrared optical range, the signature of olefins is distinct, which has allowed for the construction of an olefin-specific detector that can be used to directly determine the contamination level of drilling-fluid filtrate without the limitations of trend-fitting assumptions. A comprehensive study of eight pumpout stations from five wells has validated the performance to greater than ± 2.5 wt%, consistently delivering results superior to those obtained via conventional trend-fitting methods.

Enhancing the Look-Ahead-of-the-Bit Capabilities of Deep Directional Resistivity Measurements While Drilling

Michael Thiel, Dzevat Omeragic and Jean Seydoux, Schlumberger

The recently introduced electromagnetic look-ahead (EMLA) tool applies deep directional resistivity logging-while-drilling technology for geostopping and other applications in vertical and deviated wells. The tool shares the same basic architecture with the standard deep directional resistivity tool. The difference is that the transmitter and shallow-resistivity sensor are closer to the bit, enabling it to sense tens of feet ahead of the bit. Along with the sensor technology, the inversion-based interpretation workflow is critical for successful deployment of this service. The measurements are processed using a different strategy for look-ahead applications than the one used for reservoir mapping and geosteering high-angle and horizontal wells.

We present the details of the two-step 1D inversion-based workflow that maximizes the sensitivity of look-ahead-of-the-bit measurements. A look-around inversion first estimates the anisotropic resistivity profile and dip of the crossed layers using both conventional shallow-resistivity data and deep directional resistivity measurements. In the second step, the look-ahead inversion takes the anisotropic resistivity profile and uses the deep directional resistivity data to determine the formation resistivity profile ahead of the sensor. To make the algorithm robust, both look-around and look-ahead workflows are carefully designed, processing the most sensitive measurements within specific intervals for each inversion. In real-time applications, previous look-around and look-ahead resistivity profile estimates are used to aid the current look-ahead inversion. Furthermore, the original EMLA look-around-look-ahead (LALA) workflow is adapted to process the deep directional resistivity and conventional resistivity data, enabling improved geostopping in deviated wells compared with the conventional interpretation workflow designed for geosteering horizontal wells.

We present case studies showing the performance of the LALA workflow in detecting changes in resistivity ahead of the bit. An example from a well drilled at an inclination of 59° in Australia illustrates that the LALA workflow enables detection of the reservoir top 20 m earlier compared with the conventional inversions. Several other applications using both EMLA and deep directional resistivity from different parts of the world of illustrate successful use of the workflow to detect reservoir tops at various well inclinations.

Experimental Investigation of Mud-Filtrate Invasion Using Rapid Micro-CT Imaging

Colin Schroeder and Carlos Torres-Verdín, The University of Texas at Austin

Borehole measurements, including electrical resistivity, neutron porosity, density, sonic slowness, formation pressure, and reservoir fluid sampling, are subject to uncertainty resulting from the effects of mud-filtrate invasion. Accurate interpretation of these measurements relies on properly understanding and correcting for mud-filtrate-invasion effects. Although attempts to experimentally investigate mud-filtrate invasion and mudcake deposition have been numerous, the majority of published laboratory data are from experiments performed using linear, rather than radial geometry, homogeneous rock properties, and water-based, rather than oil-based drilling mud.

This paper introduces and applies a new experimental method developed to more accurately represent conditions in the borehole and near-wellbore region during, and shortly after, the drilling process, when the majority of wellbore measurements are acquired. Rather than using a linear-flow apparatus, these experiments are performed using cylindrical rock cores with a hole drilled axially through their center. Radial invasion is induced by injecting high-pressure drilling mud into the hole in the center of the core while the outside of the core is maintained at a lower pressure. During the experiments, the core is rapidly and repeatedly scanned using high-resolution micro-computed tomography (micro-CT), allowing for the spatial distribution of mud filtrate and mudcake thickness to be visualized and quantified as a function of time. Therefore, using these experiments we are able to accurately evaluate the influence of various rock properties, such as the presence of heterogeneity, and fluid properties, including water- versus oil-based mud, on mud-filtrate invasion and mudcake deposition.

Experimental results indicate that the presence of spatial heterogeneity in rock cores strongly influences the distribution of mud filtrate in the invaded zone. Moreover, we find that the distribution of mud filtrate around the borehole in spatially heterogeneous and complex rocks varies significantly as a function of time. In homogeneous rocks, mud-filtrate invasion occurs in a piston-like fashion, as predicted by previous experiments using filter paper and ceramic discs. Conversely, for spatially heterogeneous rocks we observe that mud filtrate preferentially follows high-permeability streaks shortly after the onset of invasion, when logging-while-drilling measurements are typically performed, and then later fills in previously bypassed zones, becoming more uniformly distributed in the near-wellbore region at later times, when wireline measurements are typically acquired. This observation has significant implications for the interpretation of formation-tester, NMR, and other measurements sensitive to the spatial distribution of mud filtrate in the near-wellbore region.

In addition, high-resolution time-lapse micro-CT images acquired during the experiments reveal notable differences in invasion and mudcake deposition behavior for water-based versus oil-based drilling muds. Consistent with field observations, we observe higher filtration rates and thicker external mudcake for water-based drilling mud. Our experiments provide visual and quantitative evidence that oil-based mud-filtrate invasion is controlled by internal mudcake, primarily consisting of trapped water droplets from the oil-based-mud invert emulsion, while water-based mud-filtrate invasion is primarily controlled by external mudcake formed when suspended solid particles are filtered out of the mud at the borehole wall.

Field Test of a HTHP Laterolog Array Resistivity and Imaging-While-Drilling Tool

Qiming Li, Oliden Technology

Laterolog-type resistivity measurement offers significant advantages over the traditional propagation resistivity in conductive mud. When implemented in a drilling collar, these types of sensors can provide not only omnidirectional resistivity measurement of much wider ranges and better vertical resolution but also high-resolution fullbore electrical images, making the tool valuable for formation evaluation and for geology and formation structures characterization while drilling. The availability of rich wellbore images has significantly improved the understanding of wellbore shapes, formation types and geology, fractures and vugs. The while-drilling electrical wellbore images also reveal the formation structure relative to the wellbore being drilled and therefore have been increasingly used to make real-time geosteeering decisions in thin reservoirs and to develop horizontal-well drilling and completion and production strategies.

To meet the ever-increasing demands of the market, a new 175°C laterolog array resistivity and imaging-while-drilling tool has been developed with the following integrated capabilities: (1) focused array laterolog resistivity with extended measurement range up to tens of thousands of Ω-m and with R_t/R_m as high as 100,000; (2) increased depth of investigation to reduce the influence of invasion; (3) bed-boundary detection capability up to 1 m from wellbore; (4) high-resolution wellbore images while rotating; and (5) quadrant azimuthal-resistivity measurement while sliding. The tool uses large electrodes to extend the range of resistivity measurement for accurate formation evaluation, and two additional small (0.4-in.) button electrodes mounted on a stabilizer to produce high-resolution electrical wellbore images. The four large quadrant electrodes, oriented 90° apart from each other, can also generate quadrant-resistivity curves at any given tool orientation, making it possible to geosteer based on resistivity measured from up and down quadrants even while sliding. Field applications in China and in the Middle East also demonstrate the value of high-resistivity carbonate reservoir delineation in conductive mud and in replacing traditional logging due to borehole-stability risks with wireline operation. High-resolution wellbore images obtained in high stick-slip environment also show the tool's capability to deal with high RPM variation during drilling.

This paper will describe the principle of measurement, introduce the new tool sensor design and configuration, and show tool-response characterization with both sophisticated modeling and laboratory experiments. Several field-test examples will also be presented with the aim to demonstrate the quality of the measurements and highlight the capability of the tool and its associated inversion and visualization answer products in applications including wellbore imaging, high-resistivity zone delineation, proactive well placement and accurate bed-boundary detection in thin-bed reservoirs. The field examples clearly demonstrate that in water-based mud, the new laterolog logging-while-drilling resistivity and imaging tool uniquely adds significant value to drilling and formation evaluation applications.

From Houston API Calibration Pits…to Artigueloutan Logging Metrological Facility

Pierre Chuilon, Gilles Puyou and Emmanuel Caroli, Total SA; Jose Inciarte, Bill Dillon, Joao Vilela and Francisco Collado, Halliburton

Following the closure of the Europa/Calisto (UK) and the Houston API (Texas, USA) logging calibration facilities, a new calibration laboratory opened in May 2018 in Artigueloutan (France) by Total SA close to its scientific and technical center located in Pau. A dedicated affiliate, Total E&P Alternative Subsurface Data (TEP-ASD) drives the project independently from the headquarters. The calibration center is open to all well-logging service providers in the industry, oil and gas companies, and academics.

The center owns 22 porous water- or brine-saturated rock standards that are the basis of any logging calibration facility. TEP-ASD is also equipped with a large set of fluid standards in four vessels, ranging from freshwater to high-salinity brines. High porosities are achieved with two sand standards made of different lithologies and fully saturated with fresh water. A thin epoxy/fiber glass liner creates a borehole where different fluids can be pumped in. A full set of metallic standards made of aluminum alloy and aluminum composite are also proposed in six different borehole diameters that can be filled with various fluids.

All standards were initially designed and modeled to calibrate logging tools in openhole conditions. The facility can also provide a collection of removable sleeves built with different casing and tubing that can be run in the rock, sand, and fluid standards. Clients can bring their own specific completion sleeves to run in the calibration facility and, therefore, follow a fit-for-purpose characterization protocol. The combination of all standards, fluids, and sleeves allows a wide range of calibration conditions, which make the TEP-ASD facility unique.

Extensive geological, geochemical, and petrophysical analyses were completed on all standards at various scales (blocks, slabs, central core, and plugs) with the latest technologies, procedures, and measuring instruments connected to the international measurement system. Uncertainties were evaluated in all steps of the process. In addition, specific upscaling and downscaling studies were performed to ensure consistency and a thorough description of the standards. All these data are made available to any client.

All calibrations can be run in two different levels: a basic option with a complete access to all standards and the characterization database, or a second degree adding the delivery of a metrological confirmation sheet after each calibration experiment.

The TEP-ASD facility in Artigueloutan can be considered as a reference for logging-tool calibration with best in class HSE and radioprotection procedures for the whole oil and gas industry in order to face the new challenges of formation evaluation.

Geosteering in Complex Channel Sands: Successful Use of a New Deterministic Parametric Inversion of Ultradeep-Resistivity Measurements

Joseph Wilding-Steele, Schlumberger

A well was drilled to target turbiditic channel sands of the Schiehallion field. The horizontal well was drilled from east to west to link multiple channel elements within the seismically mapped reservoir envelope. There were several risks associated with the well, including uncertain sand distribution and geometry within the reservoir package and a potentially swept reservoir. To mitigate these risks, reduce the uncertainties and map the position and extent of the reservoir sands, an ultradeep directional resistivity LWD tool was selected to be used.

Well data from the Schiehallion field indicated that there was the potential for significant anisotropy within the channel sands. To properly handle the complications introduced by anisotropic sands, it was decided to use an innovative, deterministic parametric ultradeep directional resistivity inversion (DPI). This new approach was selected following evaluation of the prejob study, which showed that the DPI processing could provide resolution of multiple thin layers within the sands, while also mapping the overall extent of the channel package.

In real-time, the DPI processing indicated that the maximum vertical extent of the channel complexes encountered while drilling the reservoir section was ~4 0m. This knowledge, paired with the information about channel geometry and internal architecture, enabled the planning and the execution of the most informed adjustments to the trajectory to optimize the well's position within the sands. Additionally, while drilling between sand bodies, the tool confirmed that there were no significant sand packages around the wellbore that had been missed, providing the confidence that the trajectory was drilled at the optimal TVD position. Meanwhile, the mapping of the internal channel elements within the sand bodies allowed for an increased understanding in the nature and geometries of the sands.

The success of this well has shown the benefits of using a new deterministic parametric deep-resistivity inversion. The information about the channel sands' extent and geometry as well as the identification of their internal architecture has reduced uncertainties and increased reservoir understanding.

Improving Production in Child Wells by Identifying Fractures With an LWD Ultrasonic Imager: A Case Study From an Unconventional Shale in the United States

Claudia Amorocho, Cory Langford and Gregory Warot, Weatherford International; Erich Kerr, EP Energy

High-quality images from an LWD ultrasonic imaging tool were used to identify induced fractures, map offset well communication and optimize hydraulic-fracturing practices in a series of infill horizontal wells drilled with oil-based mud.

A newly developed LWD ultrasonic imager was used to acquire wellbore images while drilling infill wells in an unconventional shale in US. In a joint effort between the service company and the operator, design engineers, and the drilling and reservoir teams optimized logging operations to acquire high-quality images used to identify and characterize fractures just hours after the well reached TD. This allowed the timely detection of zones that could be affected by offset-well interference, enabling optimization of the hydraulic-fracturing operations. Furthermore, the fracture-to-wellbore connection was mapped by integrating the image interpretation into the reservoir and geomechanical models used for field development and EOR applications in critical areas of the field.

The ultrasonic imager was run in different areas of the operator's unconventional shale acreage, providing high-quality images that allowed identification of different formation features, such as bedding planes, natural fractures, and induced fractures. The presence of fractures induced by nearby wells suggested the communication between parent-child wells in areas of the lateral. These zones were identified, mapped and isolated to mitigate the fracture interference. The child wells where this technique was used showed a more efficient use of capital expenditures and a reduction in the negative impact in parent-well production. The operator also established how the reservoir and geomechanical models in the area were fractured enhancing predictiveness by identifying detailed hydraulic-fracture interference. This allowed for better assessment of primary recovery and EOR optimization.

This case study shows one of the first proven cases where an LWD ultrasonic imaging tool was used for completion optimization and improvement of child-well production as a way to mitigate well intercommunication and field characterization.

Information Content and Resolution Potential of Deep Directional Resistivity Measurements for 3D Reservoir Mapping

Dzevat Omeragic, Schlumberger; Hanming Wang, Chevron; Hezhu Yin, ExxonMobil; Michael Thiel, Niloofar Farnoosh, Jean Seydoux and Jean-Michel Denichou, Schlumberger

The latest generation of deep directional resistivity tool generates electromagnetic ratio measurements from a full set of triaxial components extracted from individual tilted-antenna transmitter-receiver couplings. The measurements currently used for real-time interpretation are designed for 1D multilayer formations. This paper presents the extended measurement set which provides the information required for 3D steering and reservoir characterization. Spatial sensitivity plots are presented for all three harmonics both conventional 1D and 3D measurements. Examples from 1D to 3D are used to demonstrate how each measurement set contributes to distinguishing and interpreting various scenarios. The analysis is extended to drilling along the formation strike, in addition to 3D steering to lateral targets in the presence of arbitrary anisotropy, boundaries and contacts. Insight is provided on directional angles and generalized 3D propagation EM responses. Several field examples illustrate their value.

The information content of a set of real-time measurements is assessed using a data-resolution-matrix approach, adapted for nonlinear problems. The analysis is performed using the latest generation of inversions, starting from the 1D Oklahoma formation with a range of resistivities, anisotropy and bed thicknesses. In addition to finding the most important subset of measurements, this approach also helps to identify redundancy and correlations in the data and can be used to optimize the measurement set for real-time interpretation. Practical aspects of evaluation of model uncertainties through the inversion-derived model covariance matrix are presented.

Knowledge of the measurement sensitivities enables enhanced interpretation strategies to be devised. One example is the use of crossplots for steering with respect to lateral features, such as faults. A crossplot of generalized directional measurements in combination with a 1D inversion can be used to place the well with respect to caprock and oil-water contacts while detecting a lateral fault at a distance. This allows for trajectory corrections to avoid the fault, without compromising well placement with respect to the features above and below the well. Examples of artifacts seen in standard 1D real-time interpretation caused by 3D features are presented. These can be used to help identify lateral targets. A 2D inversion is used to evaluate uncertainties on several synthetic 3D models. The methodology is validated on field data where a lateral fault is crossed at high relative azimuth.

Integrated Reservoir Fluid-Mapping-While-Drilling Along High-Angle and Horizontal Wells

Artur Kotwicki and Nicolas Gueze, AkerBP; Maria Cecilia Bravo, Mirza Hassan Baig, Mathias Horstmann, Yon Blanco, Chanh Cao Minh, Julian Pop and Scott Paul, Schlumberger

Identification of hydrocarbon type, fluid contacts and assessing production potential are critical inputs to the economics of infill reserves development. Thus, highly flexible data-acquisition strategies while drilling are needed to be able to adapt to unpredictable reservoir rock and fluid properties, complex structures and variable fluid contacts.

Logging-while-drilling (LWD) technology has enabled a step change in well construction from geometric trajectories to those actively steered by formation and fluid characteristics in real time, providing information not only on the structure but also the movable fluid. Deep directional resistivity, using resistivity contrast can map hydrocarbon-bearing reservoirs but does not always differentiate between gas- or oil-bearing. It may identify an oil-water-contact (OWC) but cannot map a gas-oil-contact (GOC), nor identify API variations in the hydrocarbon column and water salinity that are crucial to distinguish injection water from connate formation water.

Leveraging short 'time-after-bit' and less exposure to drilling fluid invasion, advanced fluid-mappin- while-drilling (FMWD) tools and petrophysical interpretation techniques exclusive to LWD data have emerged, not only solving the uncertainty on fluid contacts but also identifying the movable in-situ fluid. Fluid typing from downhole optical spectrometry serve as validation points for multiphysics inversion of resistivity, electron density, hydrogen index and sigma to continuously map water and hydrocarbon properties along the well trajectory. All answers are realized while drilling for real-time decision-making.

The Boa structure in the Alvheim field, Central North Sea, is a complex structured reservoir with dynamic fluid contacts due to 10 years of ongoing production. Despite a high net-to-gross ratio, continuous mudstones and faults are present, causing reservoir compartmentalization, resulting in multiple hydrocarbon columns.

The infill development was planned in the thin oil rim of the field with a gas cap. Addressing all the challenges an integrated drilling bottomhole assembly (BHA) was run in one leg of a trilateral well: comprising deep directional resistivity to map the top and bottom of the reservoir, downhole fluid analyzer to determine the movable fluid, and advanced while-drilling log measurements to give a continuous fluid typing.

Geosteering decisions were made based on variations in the fluid encountered, a compositionally lighter fluid versus the reference was interpreted as an increase in the gas proportion of the reservoir fluid, indicating proximity to the GOC. Integration of data led to the successful development of a 6.8-km drainage length within a variable oil column that changed from 1 to 10 m TVD, identification of fluids at the landing location, continuous mapping of fluids types, contacts and hydrocarbon properties along the wellbore.

The planning and acquisition operations described show the use of an innovative workflow to achieve well-placement objectives and overcome the initial challenges imposed by fluids and reservoir structural complexity. Results demonstrated that FMWD and the integrated petrophysical workflow added significant value by aiding the placement of the well in desirable fluid type.

Monitoring CO_2 Saturation Using a Three-Detector PNC Logging Technique for CO_2 EOR in Heavy Oil Reservoir

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CO_2 enhanced oil recovery (CO_2-EOR) projects are of significance for CO_2 sequestration and heavy-oil recovery. Quantitative monitoring of CO_2 saturation (S_{CO2}) is essential to recognizing and understanding the migration and distribution of CO_2 injected into the geological formations. Comparing with pore water and heavy oil, CO_2 has zero hydrogen index and lower density under formation temperature and pressure. When the CO_2-flood is injected into a heavy-oil reservoir, the neutron moderation ability of the reservoir will dramatically change due to CO_2 gas replacing parts of the heavy oil, and they indicate such different physical characteristics using different spacing detectors.

In this paper, based on the difference in the neutron-moderation ability of CO_2, water and heavy oil, a three-detector pulsedneutron-capture logging technique is applied in heavyoil reservoirs to monitor CO_2 sequestration. We propose a new parameter, D, the difference between R13 and R23, where the counting ratio R13 representing the capture gamma ray recorded by near and far detectors, and the ratio R23 representing the capture gamma ray recorded by middle and far detectors. The difference D can be used to determine CO_2 gas saturation and the higher value of D results in more accurate estimation of gas saturation. In addition, it has higher sensitivity than counting the ratio of other two different detectors. By Monte Carlo simulation, the responses of the gamma ray count ratio versus different porosities and CO_2 saturation were studied. Then, a mathematical model of CO_2 saturation versus gamma-ray count ratio of the three detectors and formation porosity was established to quantitatively calculate CO_2 saturation. In addition, the effects of formation pressure and temperature, heavy-oil density, lithology, and other factors on the method were studied. Results show that variations of formation pressure, formation temperature, and density of heavy oil have little impact on the CO_2 saturation measurement. However, the change of formation lithology results in larger CO_2 saturation errors and requires corrections. In addition, the method has a low discrimination between CO_2 and CH_4 gas, and the results are easily affected by the CH_4 content. Finally, a simulated case demonstrates the application of the method. For the heavy-oil sandstone with different porosities, the method shows a perfect performance: the S_{CO2} errors are less than 1% for the high and low gas-saturated formation. This research provides an effective strategy to monitor CO_2 storage and residual oil saturation in CO_2-EOR reservoirs.

New 4.75-in. Ultrasonic LWD Technology Provides High-Resolution Caliper and Imaging in Oil-Based and Water-Based Muds

Peng Li, Jonathan Lee, Richard Coates and Rodney Marlow, Halliburton

Imaging technologies from azimuthal logging-while-drilling (LWD) tools provide valuable insight into borehole conditions and address multiple drilling and formation evaluation applications, such as wellbore-stability assessment and fracture and bedding-plane analysis. Although high-resolution images are widely available for water-based-mud applications, such as from azimuthally-focused resistivity tools, their availability in oil-based-mud applications is limited.

This paper presents field test results from a 4.75-in. ultrasonic imaging tool that provides high-resolution borehole caliper and acoustic impedance images, independent of the mud type used. Analysis of datasets collected in oil-based mud with varying mud weights under multiple drilling conditions are provided, highlighting the suitability of the imaging technology for multiple while-drilling applications. Log data and analysis from the field-test wells illustrate the deliverables from both the caliper measurement and the acoustic-impedance measurement. Caliper deliverables detailed include: average hole-size calculation for input into cement volume calculation, as a borehole quality indicator, and for environmental corrections for other LWD sensors; borehole ellipse and azimuthal-sector image plot outputs for real-time geomechanics analysis; and high-resolution borehole images for the identification of faults and fractures. Acoustic-impedance deliverables detailed include real-time images for potential porosity steering applications; high-resolution memory images for detailed analysis of faults and fractures; and geological and lithological analyses of bedding planes, laminations, and determination of stratigraphic dips. The caliper and acoustic-impedance datasets are compared directly with corresponding wireline measurements, including a multifinger caliper and ultrasonic imaging tool.

An overview of the tool geometry and associated sensor physics is given, along with details of the laboratory setup and

testing performed to evaluate the sensors and the associated measurements and images. Details of the field tests, which illustrate the steps taken to ensure the sensors were evaluated across different lithologies from vertical to horizontal, using different mud weights, logging speeds, and drillstring rotation parameters are described. The logging program was optimized to obtain direct correlation with wireline data sets and maximize image quality.

Analyses of the deliverables from the field trials illustrate the value that the ultrasonic caliper and acoustic-impedance measurements provide to a variety of LWD applications in boreholes ranging from 5.75 to 6.75 in., adding high-resolution imaging capability to oil-based mud systems. The excellent comparison with wireline measurements demonstrates the potential for the LWD logs to be used as the primary imaging solution in applications where deployment of wireline technologies is either risky or costly, such as in high-angle or horizontal wells, while enabling the same high level of formation evaluation.

New Advanced Material and Coating Technique for Trace Hydrogen Sulfide Sampling

Christopher Jones, Jimmy Price, Mickey Pelletier, William Soltmann, Darren Gascooke and Anthony van Zuilekom, Halliburton

The presence of hydrogen sulfide (H_2S) in a reservoir fluid can significantly impact the economic viability of a petroleum asset. Even in low PPM concentrations, H_2S can require special completion materials to mitigate corrosion problems and surface scrubbers to remove H_2S prior to transport, both of which significantly increase capital investment. H_2S also causes scale, forcing required regular flow assurance mitigation which increases operational costs. Yet, it is very difficult to capture representative fluid samples that if not captured increases asset uncertainty during formation evaluation. Specifically, H_2S chemically and physically adsorbs to the formation-tester tool flowline surface, thereby reducing the concentration in captured samples relative to true formation-fluid concentrations. This is true even with NACE-compliant materials, which do not react with H_2S but do adsorb H_2S to their surfaces. Without mitigation, formation-tester tools scrub the formation fluid of H_2S as a formation fluid passes through the tool, leading to erroneously low characterization.

Minimizing the flowline length helps lower, but does not negate, the effects of adsorption scavenging. Currently, there are specialized coatings applied to the formation-tester surface which help but have some drawbacks. In many instances, the coating durability is low. Fundamentally, all current coatings are physically adhered like paint to the tool surface and can peel by chemical attack and flake off, exposing unprotected surfaces for H_2S adsorption. Current coatings do not adhere to elastomers, which is a large sink for H_2S. Some of the more durable coatings require temperatures in excess of 800°F for application. These coatings are applied to disassembled parts, not to all tool materials, leading to incomplete coverage. For all present coatings, the process is conducted in specialized facilities negating the possibility of rapid reapplication to repair worn coatings for most field locations.

In this study, sapphire has been validated as a new material to mitigate H_2S adsorption. Sapphire has a very low adsorption affinity for H_2S so that coated materials do not scrub H_2S even at low concentrations. Sapphire, being one of the hardest materials, is highly scratch resistant and only scraped off if the underlying material is gashed. A new chemical process has been developed to deposit sapphire, which binds the coating to the formation-tester material at the molecular level. Therefore, this coating does not further peel back from the gashed site. In this study, the coating has also been shown to protect elastomers. The coating process is quick, HSE safe, and applicable at low temperature. Therefore, coatings may be reapplied to assembled field tools prior to sampling. Elastomers may also be treated with this process. Accelerated lifetime testing has shown high durability relative to tool life. Samples containing H_2S have been successfully stored in lifetime-worn bottles for weeks with no loss.

Prejob Planning Based on Nuclear Modeling Leads to Successful Downhole Mineralogy Determination in Extremely Challenging Logging Conditions

Haijing Wang, Lorelea Samano, Kenneth Kelsch, Ela Manuel and Janet Yun, Chevron

New-generation nuclear spectroscopy logging tools can provide downhole mineralogy and total organic carbon measurements in both open and cased wells. This technology is made possible by a combination of advanced physical measurements, data processing, and petrophysical interpretation. There is an emerging need to educate petrophysicists, core analysts, geologists, and other earth scientists on this technology to further expand its application, a task that requires a collective effort of nuclear experts in both logging and operating companies.

Here, we demonstrate such an effort from an operator's perspective using a case study in a carbonate reservoir. The downhole mineralogy was successfully determined despite extremely challenging logging conditions, namely a large borehole of 17.5-in. diameter and mud salinity of 130 parts per thousand (ppk) in an upper openhole section, and logging through 7-in. casing in a lower section. To justify the logging program in these extreme conditions, Monte Carlo nuclear modeling is applied during the prejob planning process to optimize logging parameters and mitigate potentially unfavorable effects of a large borehole and high salinity. During and after data acquisition, detailed data quality control with a complete set of raw and intermediate processing data helps to identify additional corrections needed for metal debris in the casedhole section. The elemental dry weights were finally incorporated into multimineral analysis, improving the accuracy of the mineralogy determination over the traditional method based on gamma-ray, neutron-density, and sonic logs, and enabling the formation evaluation through casing.

This case study was used to demonstrate best practices of nuclear spectroscopy logging and interpretation, including accurate job planning, complete raw and intermediate processing data, customized environmental corrections, and appropriate mineral models being applied. Collaborative work between logging and operating companies is critical towards expanding the operating envelope of new logging technology and advancing the general knowledge within the industry.

Pseudofocusing Processing of Array Induction Logging Measurement in High-Angle Wells

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In vertical wells, array induction logging has successfully provided resistivity logs with desirable depths of investigation (DOI) and resolutions. However, in high-angle wells, the "standard focusing" processing may fail, due to the severe dip effects. One may observe the horns on the log near formation boundaries. Moreover, separations of logs with different depths of investigation may occur in nonpermeable layers. Thus, petrophysicists could be misled in interpreting the so-called resolution-matched logs.

In this paper, we present a pseudo, i.e., an inversion-based, focusing approach to process the data measured by the array induction tool in high-angle wells. We start from the very original conductivity logs measured by the multispacing, multifrequency tool. First, skin-effect correction and borehole-effect correction are applied to the data. Then, a new set of filters were designed to acquire the logs with desirable DOI. In this process, the goal response functions in the design of the filter were chosen to be the geometric factor of a virtual subarray, who has the same configuration with the subarray of the tool but a required DOI, such as 10, 20, 30, 60, 90 and 120 in. And lastly, a layered-model-based inversion is applied to obtain the "true" resistivity logs. Note that each log, with the specific DOI, will derive an individual "true" resistivity log representing the resistivity inside the corresponding depth.

In addition, the scheme has the following considerations: (1) automatic adjustment of the boundary positions to achieve the optimal fitting; (2) noise containment to minimize the noise amplification during inversion; (3) analytical expression for the sensitivity function, or the Jacobean matrix, in a general layered transverse isotropic (TI) medium to accelerate the inversion; and (4) automatic consistency analysis of the results inverted from logs with different DOI.

Both synthetic and field datasets are processed to showcase the implementation of the proposed method. The pseudofocusing processing is proven to be stable, effective and efficient. In vertical wells, the results from the proposed approach are compatible with those from the "standard focusing" processing. While, in high-angle wells, the dip effects are eliminated to a substantial degree. The pseudofocused resistivity logs, which have desirable DOI and matched resolutions, characterize the formation radial resistivity profile convincingly, which may greatly help the formation evaluation and log interpretation in high-angle wells.

Real-Time Downhole MID-IR Measurement of Carbon Dioxide Content

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Carbon dioxide (CO_2) is an acidic gas that causes significant production problems, thereby increasing the cost of operations and the cost of capital expenditures, especially for completion and surface equipment, as well as for flowlines. In fact, the presence of CO_2 may change the economic viability of an asset, even in low concentrations. Gas-phase concentrations greater than 2-bar partial pressure are already considered highly corrosive, which may correspond to a liquid phase concentration as low as between 0.4 and 2.4 wt% for most oils. Corrosion alone costs the oil and gas industry USD 1.4 billion per year in 2016, with approximately 60% of failures directly related to carbon dioxide. Furthermore, lost production related to corrosion failures further cost the oil and gas industry tens of billions of dollars in lost revenue annually.

Multivariate optical computing (MOC) is an optical analysis technique that has been shown to match the sensitivity and accuracy of a Fourier-transform infrared spectrometer using a partial least-squares regression. MOC performs an analogue dot product regression in the optical domain, which uniquely suits MOC to allow high-resolution mid-infrared spectroscopy at high temperature. This is particularly important for downhole CO_2 measurements. The near-infrared (1,952 to 2,080 nm) region is far less sensitive for CO_2 measurements than the mid-infrared (2,686 to 2,835 nm) region, with an intensity ratio of 43 between the two regions' bands. Therefore, a new MOC sensor has been developed to access the mid-infrared (MIR) for high-accuracy carbon dioxide measurements.

Although CO_2-rich fluids may be sampled and shipped to a laboratory for analysis, selecting a location to sample can be problematic. With varying degrees of compositional grading in reservoirs, the CO_2 concentration will likely not be equivalent at all locations. Therefore, a short trial pumpout with extrapolation to reservoir concentration of CO_2 would be desirable to determine the relevant locations to sample. A new technique has been developed to accomplish this goal using the MOC sensor.

In this study, a first observation of caustic drilling-fluid filtrate suppressing CO_2 signature throughout the pumpout will also be shown. This suppression effect is reduced as the amount of filtrate present decreases during the pumpout cleaning period, but not at the same rate as the filtrate dilution effect. Therefore, a new technique has been developed to correct this effect in real time to deliver not only the instantaneous carbon dioxide concentration, but also the true reservoir concentration. Furthermore, the accuracy of the carbon dioxide measurements made in five wells, with eight formation-tester pumpout stations, has been determined as ± 0.4 wt% over a concentration ranging from 1.5 to 23 wt%.

Real-Time EM Look-Ahead: A Maturing Technology to Decrease Drilling Risk in Low-Inclination Wells

Jean Seydoux, Jean-Michel Denichou, Irlan Amir, Vera Wibowo, Thorsten Bauch, Diogo Salim, Shim Yen Han, Mauro Viandante, Guillermo Cuadros, Michiko Hamada, Sarwa Tan and Yao Feng, Schlumberger

Exploration in vertical wells has always faced many challenges related to drilling risks. Effective positioning of the casing shoe above a problematic zone or a reservoir, optimizing coring location, geostopping before potential high pressure or a depleted zone ahead of the bit, avoiding a potential kick, mud loss, or stuck pipe are some of the challenges that the industry is currently addressing in a reactive way.

With the recent introduction of the LWD EM look-ahead technology, real-time detection of resistivity features up to tens of meters ahead of the bit allows being proactive in reducing drilling risks and in successfully addressing some of the exploration challenges mentioned above.

EM look-ahead has been extensively tested in the past five years in many world locations and under different conditions with success. As this technology is relatively new and still evolving, so is the learning curve for its implementation. Most importantly, how do we make the crucial geostopping decision based on the identification and correct interpretation of target formations ahead of the bit in real time. This innovative look-ahead technology avoids unnecessary operational adjustments and setting of extra casing, thus significantly improving overall drilling efficiency and savings in overall well cost.

In this paper, the EM look-ahead technology response and sensitivity in key vertical well applications are reviewed. Field results and simulated examples provide an understanding of the technology capability, limitation, and lessons learned both in interpretation, decision taking, and operational deployment. Finally, the future of the technology is discussed.

EM look-ahead is a new and powerful technology that is expected to grow significantly in the next few years to benefit many segments of the industry as a safe and efficient addition to the exploration and appraisal phases. As the technology matures, proactivity in reducing drilling risk will become the new standard in geostopping.

Resolution Enhancement of Sonic Logs Supported by Ultrasonic Data

Jingxuan Liu, Ali Eghbali and Carlos Torres-Verdín, The University of Texas at Austin

The vertical resolution of borehole sonic measurements is mainly controlled by the length of the receiver array; consequently, sonic logs represent a spatial average of rock properties across the receiver array. This behavior makes it very challenging to interpret sonic logs acquired along thinly bedded or very heterogeneous formations. Subarray processing can yield high-resolution sonic logs but at the expense of lower signal-to-noise ratios because of fewer traces used to perform the corresponding semblance processing. The objective of this paper is to improve the vertical resolution of sonic logs by incorporating borehole images for better definition of thin beds or vuggy formations, for instance. To that end, we developed an inversion-based interpretation method for sonic logs that uses high-resolution bed boundaries obtained from ultrasonic borehole images.

Conventional forward-simulation methods, such as finite element or finite difference, are challenging in highly laminated formations because of the large contrasts between material properties involved and the presence of the internal reflections, resulting in large computation time and memory demands. To enable inversion-based interpretation, we use a new fast forward-modeling method based on spatial-sensitivity functions and combine Backus averaging when bed thicknesses fulfill the long-wave equivalent requirements to be calculated as a homogeneous anisotropic effective medium. The effective properties of thinly bedded formations obtained from sonic-dispersion curves are constrained within a range limited by the properties of each bed and depend on the layering patterns and their property variations, which is taken into account by our sonic spatial-sensitivity functions. This method was benchmarked and verified for compressional, flexural, quadrupole, and Stoneley modes in highly laminated formations. We found that the use of sonic sensitivity functions with Backus averaging yields simulation errors lower than 5% with only 2% of central processing unit time and memory demands compared to finite-element or finite-difference simulations.

The rapid sonic-modeling method was applied to fluid substitution examples to calculate differences between sonic logs acquired with and without the presence of thin laminations. The method was also implemented to perform slowness inversion of field data to construct earth models across highly heterogeneous laminated formations. Bed boundaries were defined using ultrasonic logs generated from the azimuthal average of ultrasonic images.

The combination of Backus averaging with fast forward modeling provides an effective and accurate means to quantify the frequency-dependent averaging effects of sonic measurements due to shoulder beds, thin beds, and thinly laminated formations with and without the presence of invasion. Our work underlines the importance of detecting laminations or other rock heterogeneities thinner than the length of the receiver array and quantifying their effects on sonic logs for reliable fluid-substitution calculations and hydrocarbon detection, for instance. Furthermore, the inversion of sonic logs based on high-resolution bed boundaries obtained from borehole images improves the integrated assessment of rock petrophysical properties in combination with nuclear and resistivity logs. We show several successful examples of the new inversion-enhanced sonic-interpretation method using well logs acquired in heterogeneous clastic and carbonate formations.

Well-Depth-Measurement Quality Improvement: Use of Way-Point to Improve Drillpipe Depth Measurement and Quantify Uncertainty

Harald Bolt, Depth Solutions Ltd.

Depth is the most fundamental subsurface measurement made in our business. Logging-while-drilling depths are based on driller's depths. Driller's depths have been plagued with accuracy issues, with numerous articles highlighting this.

Driller's-depth measurement is based on calibrated drillstring length, typically as identified in the "tally book". Together with the dimensions of the bottomhole assembly (BHA), the calibrated pipe length represents the calibrated drillstring length.

Way-point wireline-depth-correction methodology is applied to drillpipe-derived driller's depth. The methodology used results in arriving at corrected drillstring depth based on the calibrated drillpipe length measurement. Using this, an associated uncertainty is quantified. The objective is to arrive at "true along-hole" depth.

A crucial difference to conventional driller's depth is that the way-point method is applied uniquely when pulling out of hole using simple sliding motion. Most of the parameters that cause complications in driller's-depth correction are mitigated using this rig state. The correction contributions are limited to thermal elongation and elastic stretch but then based on measured, and not assumed, parameters.

This allows a corrected depth to be defined for the bit and the associated LWD sensors. A major improvement is that the measurement is not only repeatable, but has also an associated calculated uncertainty. The correction profiles and the uncertainty profiles are unique to each well.

The way-point method described provides corrections in wells with complex and long-reach trajectories. This includes deep offshore, horizontal and crooked wells and complex architecture drillstrings.

The objective is arriving at "true along-hole" depth, providing users of depth data with not only a depth value but also an evaluation of the accuracy of the depth data. This means that the depth data from drillpipe can be independently evaluated against other sources of depth data, such as wireline. The typical "tie-in" is then no longer necessary, as depth-data measurements can then be used to verify measurements instead of simply complying to an arbitrary maxim.

An example is discussed where way-point is used to improve drillpipe-derived well depth and quantify the depth-measurement uncertainty.

RESERVOIR AND PRODUCTION SURVEILLANCE

'Log-Soak-Log' Experiment in Tengiz Field: Novel Technology for Uncertainty Reduction and Decision Support in an Improved Oil Recovery Project

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Waterflood design in tight naturally fractured carbonate reservoirs (NFR) significantly differs from the conventional ones. Despite the fracture-network dominance in reservoir connectivity and well deliverability, the majority of hydrocarbon is stored in the tight matrix. Incremental recovery from the waterflood in a NFR will often depend on the rate and magnitude of water imbibition into the matrix. If it is found that injected water only displaces the oil in the fractures and leaves matrix oil unrecoverable, the value of the waterflood is limited to the oil volume in the fractures.

Laboratory measurements of spontaneous imbibition on the core plugs can be inconclusive due to several limiting factors including experiment temperature and pressure limit, use of synthetic fluids, core-plug size limits, core preservation and aging uncertainties. To resolve this uncertainty, the asset team designed a single-well pilot named "log-soak-log" (LSL) to quantify incremental oil recovery from the matrix due to imbibition of water. The purpose of the pilot was to recreate an imbibition experiment at well-scale with in-situ fluids and conditions and monitor matrix imbibition through time-lapse log measurements.

In-situ log measurements of water imbibition posed several unique challenges related to fluid placement in the naturally fractured reservoir, high measurement uncertainty in low-porosity rock, potential wettability alterations in the near-wellbore region, through-tubing tool conveyance, elevated operational risks due to highly corrosive logging environment and presence of H_2S and inability to maintain fluid level during the experiment.

This paper describes the design, execution and evaluation of the LSL pilot conducted in a giant naturally fractured tight carbonate reservoir in Western Kazakhstan, where repeatable and reliable measurements of changes in water saturation were achieved across large intervals (tens of meters) using time-lapse pulsed-neutron logging techniqúse. Periodic time-lapse measurements provided valuable observations of dynamic saturation and fluid-level change with time and allowed estimation of the rate and magnitude of imbibition in the near-wellbore region. Incorporation of the LSL results into the reservoir model validated the ranges of current water relative permeability curves, residual oil saturation to water, irreducible water saturation, and capillary pressure assumptions. This resulted in significant reduction of the key uncertainties of the IOR project and the updated oil-recovery forecast.

Cement-Bond Evaluation With a Logging-While-Drilling Sonic Tool

Franck Michel, Ruijia Wang, Chung Chang, Richard Coates and Jonathan Lee, Halliburton

A cement-bond log (CBL) plays an important role when evaluating the quality of cement behind casing and determining well integrity, which in turn helps to ensure zonal isolation and wellbore protection. Logging-while-drilling (LWD) sonic tools provide an economical solution for locating the top of cement and determining the cement-bond index, particularly for highly deviated wells, due to the ease of conveyance. In general, LWD tools can make time-lapse measurements and save rig time and cost by eliminating separate wireline runs. However, LWD sonic measurements are often contaminated by the tool-wave mode and road noise, resulting in biased casing-wave amplitude and attenuation estimates. Using these biased measurements directly can yield an unreliable bond index (BI), particularly for zones where the tool waves are significantly stronger than casing arrivals. These challenges can be overcome as demonstrated in a field-data example with both free casing and well-bonded zones.

The paper describes a quantitative cement-evaluation method developed using LWD monopole data. The method uses the characteristics of LWD sonic tools—the tool waves have an intrinsic stop band in excitation, and the tool-mode speed is slower than the casing wave.

During the first step of the process band-pass filters are developed and applied to extract casing waves in the intrinsic stop band of the tool mode. The waveforms of a single-shot data recorded by different receivers are then stacked to a reference receiver with

different weights to further suppress the tool-wave arrivals and increase the signal-to-noise ratio (SNR). The weights are calculated according to the speed differences between the casing and tool waves. The remaining tool waves after the array processing are predicted by multishot data, including both a free-casing zone and a well-bonded zone. A simplified tool-casing-wave model is developed and applied to describe and predict the interference phenomenon between the casing arrival and the tool arrival. The tool-wave signals are calculated from the well-bonded data by subtracting the casing-wave predictions calculated from the free-casing data with modeling predictions. The true casing-wave amplitude is estimated from the filtered waveforms and calibrated by subtracting the tool-wave predictions. A BI log is then calculated from the calibrated casing-wave amplitude.

This new processing technique was applied to a field-data example exhibiting both free-casing and well-bonded zones. Both the CBL amplitude in mV and BI log are extracted from the LWD sonic data and compared with BI estimated from a wireline segment bond tool (SBT). A good match is obtained over the entire log despite the fact that a casing pressure test was conducted between the acquisition of the LWD sonic and wireline data, which might have created microannuli detected by the SBT measurements.

The proposed approach promises to be a significant step toward deriving a quantitative CBL from LWD sonic monopole data.

EOR Pilot Performance Evaluation in a Giant Mature Field in Argentina

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In both well operations, the target reservoir was an eolian dune and interdune sandstones initially considered as a fairly vertically homogenous layer.

The first test was performed in Well A to evaluate the residual oil saturation (S_{or}) to waterflooding and the performance of a subsequent alkali-surfactant-polymer (ASP) injection.

Due to the great areal extension of the target reservoir, the second test was implemented in Well B in order to confirm the results of the first well, and to integrate different characterization tools that helped us interpret results.

Each well operation consisted of two single-well chemical tracer tests (SWCTT), well logging and testing tools implemented prior to, during and after the injection of the EOR process.

The SWCTT technology was designed and executed to gain insight of EOR potential in deep reservoir areas. Due to integrity issues of old wells, different procedures were used to detect and guarantee hydraulic isolation of the target zone. Fluid-saturation logs were used to measure the vertical sweep efficiency. In the second operation, production logging tools were used to determine the injectivity distribution and helped to improve the conformance during the test.

It was important to confirm zonal isolation because drawdown tests showed the need to cement the underlying perforations for hydraulic isolation of the target zone. Conservative tracers confirmed that the target zone was effectively isolated during the test.

Production logging tools allowed identifying the presence of high- and low-permeability layers. This tool and the conservative tracers allowed to characterize the crossflow between dune and interdune.

Conformance was improved with a carefully designed low-permeabilty layer stimulation. An improvement of 80% in the conformance was confirmed between wells with the use of saturation logs.

Both tests confirmed positive results. A 19% improvement in S_{or} reduction was observed between wells.

This paper presents the first tests of this kind performed in Argentina to define EOR potential in a low oil-price environment. Complementary tools helped to support and enhanced the interpretation of the SWCTT results. ASP formulation has been positively evaluated as an EOR prospect at field-scale in Argentina.

From the Borehole Wall Into the Formation—Combining Borehole Images With Deep Shear-Wave Imaging Technology

Stefan Schimschal, Stephen Fayers, Nicklas Ritzmann and Martin Cox, Baker Hughes, a GE Company; Iain Whyte, Tullow Oil

One major challenge of integrating borehole image and geophysical measurements is to bridge the gaps between their dissimilar resolutions. Identifying and characterizing geological features, like bedding contacts and fractures, by combining high-resolution borehole images with deep shear-wave imaging (DSWI) technology, helps to bridge these gaps. Ultimately this will add to a refined, more accurate subsurface reservoir model.

High-resolution borehole images are suited to identify fractures, bedding, dip information, facies types and other properties along the borehole. Besides coring, this evaluation method reveals the highest resolution geological details, resolving features down to ~0.2 in. Despite the high detail, these images represent only a localized view of the wellbore wall.

Borehole acoustic measurements can be separated into different acquisition methods to determine various properties along and away from the wellbore. One of these methods, deep shear-wave imaging, uses crossed-dipole waveform data, around 2 kHz, in combination with simultaneously acquired orientation data. Deconvolution, orientation and migration of the waveform data produces an orientated reflector image, separated into up- and down-going reflector image-bins located in the sagittal plane. The associated vertical and horizontal resolution is approximately 3 to 3.5 ft. The depth of investigation is dependent upon the formation slowness and 'listening time' of the acoustic measurement, but can be up to 100 ft into the formation. Subject to suitable acoustic contrast and relative dip to the borehole, a dipping geological feature away from the borehole may be resolved as a reflector on the image, from which its lateral continuity, dip magnitude and strike may be determined.

In this paper, we present a case study showing the full integration of both imaging methods. Picked reflectors in the deep-shear-wave image allow correlation with corresponding geological features on the borehole image. Identifying the dip azimuth of a reflector from the measured orientation of the corresponding feature on the borehole image enables the rotation of the sagittal plane in the deep-shear-wave image. With this borehole image-based adjustment the reflector plane of the deep-shear-wave image is shown in its correct aspect and positioned correctly in the subsurface.

Combining borehole imaging and acoustic DSWI methods allows the identification and characterization of geologic features at the wellbore and their propagation into the formation. This input can help to refine the structural model of the subsurface, obtained from surface-seismic measurements, and thus enables us to bridge the gap between borehole-wall measurements and geophysical characteristics away from the wellbore. In addition to this, integrating feature characterization and measured dip information from the borehole image significantly improves our understanding and interpretation of the DSWI result.

Increasing the Dimensional View in Both Cement Evaluation and Mechanical-Integrity Surveillance Delivers Solutions Beyond the Current Norm

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Cement-evaluation results are commonly presented in a standard two-dimensional (2D depth and azimuth vs. bond) log format, while casing-inspection results might include three-dimensional (3D depth and azimuth with projected radius vs. thickness) images. Incorporating 3D images supporting cement evaluation provides an enhanced visualization-based interpretation capability and improved decision making. Incorporating a time-based surveillance monitoring (4D) with current casing-evaluation techniques provides pipe-integrity inspection solutions to operators that pushes the envelope beyond current industry norms.

Ultrasonic-based casing inspection and existing post-processing software creates multiple images, curves, spreadsheets, and statistics designed to pinpoint areas of casing damage. Additionally, high-resolution passes could be made to create 3D images of the casing geometry including portions with damage. Applying the same 3D imaging technique to cement evaluation allows increased comprehension of the cement-sheath characteristics, particularly extending away from the immediate casing wall-cement contact. An analysis method was developed to evaluate the behavior of standard CBL refracted waveforms is also applied directionally to the multiple waveforms from the Segmented Bond tools. This process allows detailed interpretation of the entire cement sheath between the casing and formation. It is possible to detect channels or problem areas in the annular space with this new process. Taking the results of the processing another step it is possible to create 3D images, along with cross-sectional views, which allow easy visualization of the annular volume. The results of the processing and resulting images help illuminate inferior cement sheaths that do not provide the desired zonal isolation and help determine the reasons for the unwanted fluid production.

When handling riser inspection, or monitoring casing wear, it is important to scrutinize changes in the pipe condition over time to meet governmental regulations. Visually comparing the logging runs is the standard legacy methodology, but this is extremely time-consuming, particularly when comparing large amounts of data. This paper demonstrates a new technique to observe these alterations of the pipe conditions over time, both on a depth-by-depth and joint-by-joint basis. This new 4D surveillance interpretation method, accepted by the Bureau of Ocean Energy Management (BOEM), allows the operator to complete pipe inspections quickly and to continue drilling with confidence.

Novel Coupling Smart Seawater-Flooding and CO_2-Flooding for Sandstone Reservoirs; Smart Seawater-Alternating-CO_2-Flooding (SMSW-AGF)

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The ever-growing natural decline in oil production, recently oil prices cut, in addition to the global energy demand have been the main motivations to pursuit for cost-effective IOR methods to increase recovery efficiency, especially heavy-oil accumulations. It is traditionally well known that heavy-oil IOR techniques are costly. Currently, smart water, low-salinity water and CO_2 are the most economically viable IOR techniques. We propose a new method to improve oil recovery via synergistically smart seawater with CO_2.

In order to evaluate our new proposed method, several successively coreflood experiments using smart water and CO_2 were conducted. The coreflood experiments include sequentially injection of sweater, smart seawater, and ultimately CO_2 in reservoir sandstone cores taken from the Bartlesville Sandstone reservoir (Eastern Kansas). The coreflood experiments provided a very promising results that could change traditional EOR methods.

The cores were delivered fully saturated with oil and well-coated with a plastic wrap. The cores were cleaned by Soxhlet extractor. The cores were transferred to a vacuum container for evacuation purposes. A one-day vacuum was performed on all the cores, after that, synthetic FW was presented to the cores under vacuum. Porosity and permeability were measured. The FW was displaced by 3 pore volume (PV) crude oil in both directions to establish S_{wi}. The cores were then aged in the crude oil for three weeks at 90°C to restore the initial wettability.

After the pre-aging duration had completed, the cores were then flooded with two pore volumes (PV) of seawater (SW) followed by three PV of SMSW, and then six PV of CO_2 at 45°C. SW and SMSW were injected into the cores until no more oil was produced and the pressure was stabilized. The reservoir cores were flooded using the following scenarios:

1. RC3a was flooded with SW followed by CO_2.
2. RC3b was flooded with SW followed by SMSW1 and CO_2.
3. RC3c was flooded with SW followed by SMSW2 and CO_2.
4. RC3d was flooded with SW followed by SMSW3 and CO_2.
5. RC3e was flooded with SW followed by SMSW3 + CO_2 but in shorter cycles using our proposed design for low-salinity-alternating-steamflooding (LSASF), 0.5 PV CO_2 + 0.5 SMSW3 + 0.5 PV CO_2 + 0.5 PV SMSW3 (Less injected PV, but more recovery ever).

Using the same brines that were used in the coreflood experiments, contact-angle measurements on the same core materials was performed. The results of contact-angle measurements confirmed a wettability alteration of the rock surface towards more water-wet using our new EOR process.

The coreflood experiments of all scenarios resulted in additional oil recovery, but the optimum scenario was the scenario (5) with incremental oil recovery 24.5% of OOIP beyond the 55% of OOIP from injecting FW. The short cycle injected of LS water and CO_2 are, the more oil recovery was obtained.

This combination technology can solve the CO_2 flooding problems (channeling, gravity override, etc.) and support the CO_2 by SMSW, which is itself has the ability to increase oil recovery by altering the wettability towards more water-wet.

The Neutron Dance: A Quest for Reliable Casedhole Neutron Data for High-Temperature Steamflood Surveillance

Abbie Morgan, Aera Energy LLC

The Midway Sunset oil field in the San Joaquin Valley of California is one of the largest fields in the United States, having produced approximately three billion barrels of oil out of various reservoirs. Many of these reservoirs contain heavy oil, requiring recovery by steam to reduce the viscosity of the oil and allow it to flow. In steamflood operations, monitoring the steam distribution and behavior is necessary for effective steam management and identification of bypassed oil. Casedhole neutron logs are critical to this surveillance and are acquired throughout the life of the steamflood operation using cased observation wells. Each subsequent casedhole neutron porosity is compared to the original openhole neutron porosity to determine the increase in steam saturation and corresponding decrease in oil saturation that has taken place since the well was drilled. These logs are used to define current steam-oil contacts throughout the field, allowing reservoir teams to modify steam injection accordingly. There are many casedhole neutron tools available, but they vary in tool characteristics, benefits and costs. Some tools can only be run in temperatures lower than 300°F, while steam-chest temperatures can reach 350°F, or more. This constraint leaves fewer tool options for some wells, and the data from these tools has not always been reliable. To better define the quality, limits and value of this data, we test multiple high-temperature neutron tools, including both chemically sourced and electrically sourced tools, by running them in a new well immediately after completion to compare them directly to the openhole neutron log and to each other. We analyze the data quality, benefits and costs of the different tools and design a plan for our future surveillance.