Integration of experimentally derived rock properties into characterization workflows

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Summary
The integration of plug and log scale characterization is key to generating representative petrophysical and geomechanical models at all stages from exploration and development to production. The importance of plug measurements is especially vital in finely laminated rocks where well-log scale measurements miss mechanical heterogeneities that are required for realistic mechanical models. The presence of mechanical heterogeneity and anisotropy under the well log resolution is commonplace in unconventional plays and can deeply impact geomechanical assessments ranging from wellbore integrity to horizontal stress estimates. Yet, in order to fully realize the value of lab-based geomechanical characterization, it appears critical that laboratory workflows be optimized in terms of both outputs and turnaround times.

In this paper, we present an in-house core scanner for fast and non-destructive physical measurements (not just scanning) of elastic, transport and compositional properties of rocks at a very fine scale (down to sub-mm) as well as a set of workflows to incorporate aforementioned properties in unconventional reservoir characterization.

Introduction
AutoScan (Fig 1) is a laboratory core scanner that allows spatially coupled, point-focus scanning of core or benchtop samples for Fourier Transform Infrared Spectroscopy (FTIR), mechanical hardness, gas permeability, resistivity, and ultrasonic compressional and shear wave velocities. Physical properties measurements are made on user-defined grids, lines, or points at spacings as small as 0.1 mm over length scales of 1 meter, which permits the detailed study of multiple meters of core in a single setup. The ability to combine velocity, permeability, and resistivity scanning offers a unique capability for core selection and screening, log calibration, and petrophysical rock type identification. Once petrophysical properties are acquired, a number of protocols are used to help constrain petrophysical models of transport and elastic properties with geochemical, mineralogical, and microtextural characteristics.
Figure 1 AutoScan – robotically-controlled gantry system for physical property measurements of several

Figure 2: Geostatistical cluster analysis is used to find regions of the sample that are petrophysically
Theory and/or Method
The first part of the presentation will focus on a few laboratory-based inputs that are increasingly being recognized as high impact and which are progressively becoming more routine at a number of vendors. More specifically we will address the topics of continuous mechanical profiling (mm to inch-scale heterogeneity assessment), non-uniform core plug selection based on acquired petrophysical data and recommended rock typing routine.

Then we will address the optimization aspect, which is no less essential in realizing the value of laboratory-based characterization. To that effect, we will suggest ways to greatly increase workflow relevance and efficiency by relying on the use of petrophysical core scanning for screening, rock typing and core plug picking. New closed loop workflows allow for upscaling laboratory observations to the wireline log scale at different stages of the process, thus providing an early option for decision making.

Examples
A 350-ft section of slabbled core from Wolfcamp shale was analyzed and measured at mm-scale to quantify heterogeneity in sonic velocities, FTIR and mechanical properties (Young’s Modulus). The measurements were then calibrated to more conventionally derived measurements and upscaled to provide predictive power and direct comparison to wireline log derived data (Fig 3).

Conclusions
The combination of fast and non-destructive physical property measurement platform with workflows capable of relating these measurements across scales is a powerful tool at all stages of field life from exploration and development to production.

References

Figure 3: Comparison of wireline-log derived compressional sonic velocity with upscaled velocity.
Micro-Imaging Porosity Preserving Microcrystalline Quartz in Deep, Hot Sandstone Reservoirs

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Abstract
Authigenic quartz cement is the most common pore-occluding mineral in deeply buried (>2500 m) quartzose sandstones. Deeply buried reservoirs in the North Sea contain more porosity than expected when the influence of microcrystalline quartz (microquartz) is ignored. Anomalously high porosity in these North Sea rocks typically correlates to observation of microquartz and sponge detritus (Taylor et al., 2015). However, we know little about the nature and origin of microquartz. We have utilized advanced analytical capabilities to improve our understanding of controls on microquartz development in several examples where porosity is preserved in deeply buried sandstone reservoirs.

In this study, several advanced analytical techniques were used to evaluate the crystallographic and compositional controls on the formation of microcrystalline quartz. SEM/Cathodoluminescence (CL) confirms that quartz overgrowths have a complex growth history. Previous workers (Kraishan et al. 2000) suggested that CL patterns in quartz cement are largely due to trace elements rather than defects and that aluminum varies consistently between each cement phase. Electron Backscatter Diffraction (EBSD) combined with Wavelength Dispersive Spectrometry (WDS) confirms that the complex banding visible in CL is not due to changes in crystallographic orientation but more likely variations in quartz composition associated with changes in pore fluid composition and/or reservoir conditions. Secondary Ion Mass Spectrometry (SIMS) analysis provides maps of ultra-trace element distribution that confirm that trace amounts of iron, manganese, and titanium can be used as proxies for defect density and temperature. Additionally, SIMS analysis provides oxygen isotope data providing insight into the initial reservoir conditions and temperature of formation of microcrystalline quartz in several formations.

Integrating the results from these advanced analytical techniques has helped us develop our understanding of the processes controlling the formation of quartz cement and improved our ability to reconstruct the reservoir diagenetic history of quartz growth leading to a proposed model for predicting porosity preservation in deep, hot sandstone reservoirs.
Quantitative 3D analysis of micro-pore networks in tight oil and gas reservoirs using confocal laser scanning microscopy (CLSM)

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Abstract
Unconventional oil and gas reservoirs comprise complex submicron-scale porosity networks. Understanding the connectivity of these networks in three dimensions is of paramount importance for reservoir characterization. However, the small pore and pore throat sizes of these complex porosity networks can pose a challenge to widely applied visualization techniques, either because resolution is too coarse, or the sample area is too small and thus results are not representative of the entire porosity framework. Confocal laser scanning microscopy (CLSM) has proven a promising 3D visualization technique that provides a compromise between improved resolution (down to ~300nm horizontal resolution) and larger sample size – pore networks can be derived from standard thin sections – thus making it an ideal method to quantify pore networks in tight oil and gas reservoir rocks.

Previous work on tight reservoir sandstone samples has shown that CLSM can reliably visualize pore network in three dimensions using a z-stack slicing technique. In this study we extend on this previous work and present results of a novel technique that uses CLSM derived z-slices to create full 3D pore volumes of micropore networks. We then used these 3D volumes to quantify the heterogeneity of the vertical and horizontal porosity networks by comparing pore geometries and connectivity. In a last step we used this data as a proxy to quantify the (an-) isotropic permeability in these tight reservoir rocks. Samples in this study are from a variety of rock types and basins, including tight oil reservoir rocks from the Powder River Basin and the Williston Basins.
Investigation of the Shale Electrical Resistivity Reversal Commonly Observed at the Wet- to Dry-Gas Transition

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Abstract
Shale reservoirs exhibit evolution of resistivity with a noted reversal typically occurring at the wet- to dry-gas transition. This study documents this phenomenon and investigates mechanisms that cause and influence the reversal.

In many shales, resistivity evolves from low resistivity at low thermal maturity, increases with increasing maturity, commonly peaking in the wet-gas window, and then decreases at the wet- to dry-gas transition. In highly organic shales at very high maturities (%Ro>3) resistivities can be up to three orders of magnitude less than observed in the same formation at peak resistivities. Resistivity changes can be related to changes in water saturation and distribution, resistivity of the water, mineral matrix (e.g., clays, pyrite, organic matter), or pore network. These, in turn, are related to evolution of mineral and fluid properties, fluid-rock properties, porosity, and pore-size distribution. Two key variables are wettability and capillary pressure (Pc) which influence water saturation (Sw) and distribution. Thermal maturation of kerogen from oil generation onset through wet gas involves both expulsion of polar hydrocarbons from the kerogen that can partially wet adjacent mineral surfaces and the development of partial to fully oil-wet porosity within the organic matter (OM). Increase in oil wetness decreases Pc and the continuity of the water-wet surface which increases resistivity. Further thermal evolution causes cracking of polar, surface-wetting, heavy hydrocarbons to lighter, non-polar, non-surface-wetting hydrocarbons. This decreases oil wetness and associated electrical resistivity. Concurrently, free hydrocarbons undergo cracking from low API/low gas-oil ratio (GOR) to high API/high GOR. The associated decrease in contact angle acts to increase Pc. At constant hydrocarbon pressure, an increase in Pc might increase Sw and bulk volume water (BVW), or cause expulsion of hydrocarbons from small pores, which decreases resistivity.

Other mechanisms that can act to decrease resistivity to varying degrees include: increasing aromaticity and graphene within kerogen, increasing pyrite content, and increasing brine
salinity associated with water vaporization in overpressured expelled gas. Conversely, mechanisms that can act to increase resistivity include: porosity occlusion, pore-throat size decrease, and decrease in clay cation exchange capacity.

Resistivity reversal is a significant phenomenon and is exhibited on well-log cross sections for the Niobrara Formation in the Piceance, Sand Wash, and Denver basins (Al Duhailan and Cumella, 2014) and is observed in other shale formations (e.g., Woodford, Barnett, Fayetteville, Eagle Ford, Marcellus, Utica, Mowry, Mancos, Vaca Muerta). Understanding and quantifying this phenomenon is important for accurate log-saturation determination and may be used to map the wet-to-dry-gas transition for shale reservoirs.
Application of Integrated Core and Multiscale 3-D Image Rock Physics to Characterize Porosity, Permeability, Capillary Pressure, and Two and Three-Phase Relative Permeability in the Codell Sandstone, Denver Basin, Colorado


Abstract

Objectives: The Codell Sandstone is an important resource. Core analysis (CA) on these heterogeneous rocks accurately measures porosity (φ), permeability (K), saturation (Sw) and capillary pressure (Pc), but is challenged to measure two- and three-phase relative permeability (2-P and 3-P Kr). Image-based rock physics (IBRP) provides these data. This study developed an integrated CA-IBRP workflow, with a robust method for integrating porosity phases at two different resolutions (e.g., FIB-SEM & µCT), to obtain representative elementary volume pseudoproperties for use in reservoir modeling. Procedures: Using a workflow integrating CA and IBRP (focused-ion beam scanning electron microscopy, FIBSEM & x-ray micro-computed tomography, µCT), we characterized samples representative of the Codell. The workflow starts with identification of representative lithofacies from core/logs. K, φ, Sw, and Pc are measured using CA. µCT is then used to characterize the distribution of the five principal µCT-image phases; grains(G), intergranular φ (IG), large clay (kaolinite) + intercrystalline φ (IX), small mixed-layer clay + microcrystalline φ (MIX), and altered lithics + intragranular φ (ING). IG, IX, MIX, and ING are then imaged with FIB-SEM at respectively appropriate resolutions and quantified using artificial intelligence-based image analytics. Results: Using the images, IG+IX and MIX+ING permeability were computed using Navier-Stokes-based Computational Fluid Dynamics (CFD) methods. IG+IX and MIX+ING capillary pressures were computed using digital porosimetry. Stationary 2-P & 3-P Kr were computed using image-based CFD at multiple saturations captured by porosimetry simulation. These FIB-SEM scale phase properties (φ, K, Pc, 2-P Kr, 3-P Kr) were assigned into µCT phases to calculate the corresponding pseudo-properties based on an upscaling model. After crosscalibrations between IBRP-estimated µCT pseudo-properties and CA properties, and confirmation that µCT volumes are representative elementary volumes, complete 2-P Kr and 3-P Kr curves across the full spectrum of K-φ were constructed. This workflow provided the
suite of properties that cannot be obtained easily with CA. Application: Multiscale IBRP reproduced CA $\varphi$, K, K-$\varphi$, Pc relationships. Calculation of complete 2-P and 3-P Kr utilized the same methods as 2-P Kr. Cross-validated IBRP and CA is an extremely powerful tool for microdarcy rocks with heterogeneity. IBRP provides unique data particularly in assessing Kr relationships and evaluating sensitivity to controlling variables. The workflow utilized in this study can be applied to many multiphase/ multifacies models. Properties computed herein have been used in reservoir- and well-scale numerical flow modeling to support exploration, completion and production management decisions.
Wettability and Water Cut Prediction in the Delaware Basin

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**Abstract**

Water production and handling results in high operational costs for wells in the Delaware Basin Avalon, Bone Springs and Wolfcamp formations. Most wells make between 50 and 90 percent water cut in the part of the play that has high hydrocarbon liquids production. Most other organic shale plays do not produce the volumes of water seen across the Permian Basin plays. Understanding, predicting and minimizing water cut could increase profitability in these plays.

Variable water cuts in wells with similar calculated water saturations and high variability in reservoir recovery factor by zone are observed and influence development planning. Recognizing and determining different reservoir wettability and applying that to production prediction can explain some of the observations above.

This early work suggests that changes observed in resistivity behavior may identify water or oil wet tendencies in these reservoirs. Reservoir wettability will be predicted using resistivity ratio (DEW) plots. Reservoir wettability is a controlling influence on water cut. In a reservoir with movable water, the hydrocarbon-wet reservoirs will tend to produce more water than the water wet reservoirs at a given saturation and similar fluid properties.

Fluid displacement in the shallow borehole is observed in open hole resistivity and dielectric logs. Resistivity ratio plots could be indicating interval productivity tendencies by showing a combination of flushing and imbibition.

Predicted reservoir wettability plotted in xsections illustrates the stratigraphic nature of the formation wettability and provides a way to predict water cut by targeting reservoir intervals of different wettability and hydrocarbon saturation.

The ability to predict reservoir wettability characteristics and potentially water cut with currently available data will be highly valuable for development planning in these large-scale developments.

**Bio**

Michael (Mike) Miller PhD is a geologist with 30 years of varied geologic and petrophysical experience. Mike is currently the Chief Petrophysicist at Cimarex Energy and periodically helps to teach courses at the University of Tulsa. Previously he was the Senior Petrophysical Advisor for Unconventional Resources at BP, a graduate and a team lead for the Amoco Petrophysics program. Mike is a member of the AAPG, the Tulsa Geologic Society, the SPWLA, and the Denver Well Logging Society.
Tank Development in the Midland Basin, Texas: a case study of super-charging a reservoir to optimize production and increase horizontal well densities

Jill Thompson (geology) & Nick Franciose (reservoir engineering) will co-present

Abstract
Simultaneous petroleum extraction operations, including drilling, completion, and production of tightly spaced horizontal wells are the inevitable reality in unconventional development. This next wave of development has just begun in the Midland Basin of West Texas, where operators are shifting from parent well tests to increased well density development. However, the development of increased well densities in a sequential, parent/child methodology commonly results in less effective stimulated rock volumes of child wells, increased production downtime, and drilling hazards. The key to maximizing corporate value will be in adopting development strategies that realize higher well densities while avoiding these pitfalls. Here we present a case study of a novel multi-disciplinary approach aimed at the optimization of both surface and subsurface development operations for tightly-spaced and stacked stratigraphic intervals. Our methodology, here termed “Tank Development”, aims to exploit a volume of rock at one time to maximize reservoir potential. The fundamental principle of Tank Development is maximizing well productivity by “super-charging” the reservoir prior to simultaneous initiation of production. Super-charging the reservoir is accomplished by sequencing hydraulic fracture operations and bringing all wells online simultaneously to pressurize the reservoir in an effort to create a demonstrably more complex fracture network. A surface microseismic array was used to monitor the completions of four horizontal wells in the Spraberry Formation. The results indicate evidence of breaking more rock when Tank Development is employed. Microseismic data also show an increase in near-wellbore fracture complexity for wells that were stimulated later in the Tank Development sequence. The principle result from our tests is that productivity indexes for wells in our Tank Development program clearly exceed the productivity indexes for wells from the industry standard parent/child well development methodology. Thus, the new development approach has proven essential for maximizing asset value during simultaneous development of multiple horizons with horizontal wells in close proximity to one another. This multi-disciplinary
development approach is key to optimizing near-wellbore fracture complexity and the conservation of completion energy required for increased well densities. In addition, Tank Development effectively eliminates the detrimental effects of parent and child well interactions. The surface and subsurface efficiencies maximize oil recovery and corporate value.
Abstract
Considering the complexity of modern unconventional petroleum systems, development teams often rely on loose statistical relationships derived from distant offset well properties when attempting to predict provable reserves, rather than geological and reservoir science.

To greatly improve our understanding of unconventional reservoir behavior, it is necessary to combine our conventional knowledge of geology, reservoir engineering and completion engineering, using a workflow combining reservoir modeling, hydraulic fracture modeling, and reservoir simulation.

This paper demonstrates a practical workflow for this union. It is shown that by importing complex hydraulic fracture geometry and permeability directly into a fully coupled reservoir simulator, a much more realistic production match can be obtained that provides a better tool for production forecasting.
The Eagle Basin of Northwest Colorado: A Compartmentalized Evaporite Basin and Large Hydrocarbon Frontier

Connie Knight, Independent Geologist

Abstract
During the past two decades we have witnessed significant changes regarding recognition of low-permeability sandstone, carbonate, and shale reservoirs as desirable exploration targets. The interplay of source-rock geochemistry, structural geology, burial history analyses, and reservoir diagenesis studies has revolutionized exploratory techniques in these tight rocks.

The Eagle Basin, a Pennsylvanian (predominantly Desmoinesian aged) evaporite basin located in northwestern Colorado, contains widespread carbonate rocks and black shales that are exploration targets for oil and gas reserves. During Pennsylvanian time the Eagle Basin was part of the Central Colorado Trough, which was bounded by ancestral mountain-range uplifts.

The thick sequence of Desmoinesian cyclically deposited evaporites, carbonates, and black shales, commonly referred to as the Minturn Formation and its equivalents, bears a striking resemblance to the coeval Paradox Formation of the Paradox basin. Normal marine and penesaline facies are found flanking hypersaline halite facies in both basins. Over the past decades, various interpretations regarding the source rocks for Minturn oil have been discussed. Recent studies reveal that the productive sections of the Minturn Formation consist of low porosity, self-sourced, and likely over pressured carbonate rocks.

Geologists have assumed that the northwest portion of the Central Colorado Trough is one large evaporite depocenter. By using conventional well logs and subsurface rock samples, the Desmoinsian aged section of northwest Colorado has been subdivided into individual rock packages. The Eagle Basin is here interpreted to be a series of four or five smaller basins, each basin having served as a center for halite accumulation. Halite sub basin margins are attractive hydrocarbon targets where fault related fracturing and hydrothermal activity have enhanced reservoir permeability. Reserve estimates can be high with one specific prospect reserve estimate in excess of 400 million barrels of oil equivalent.