GMC Technical Breakout Session

2019

In connection with the 2019 Alaska Oil & Gas Association Conference

North Slope Technical Session

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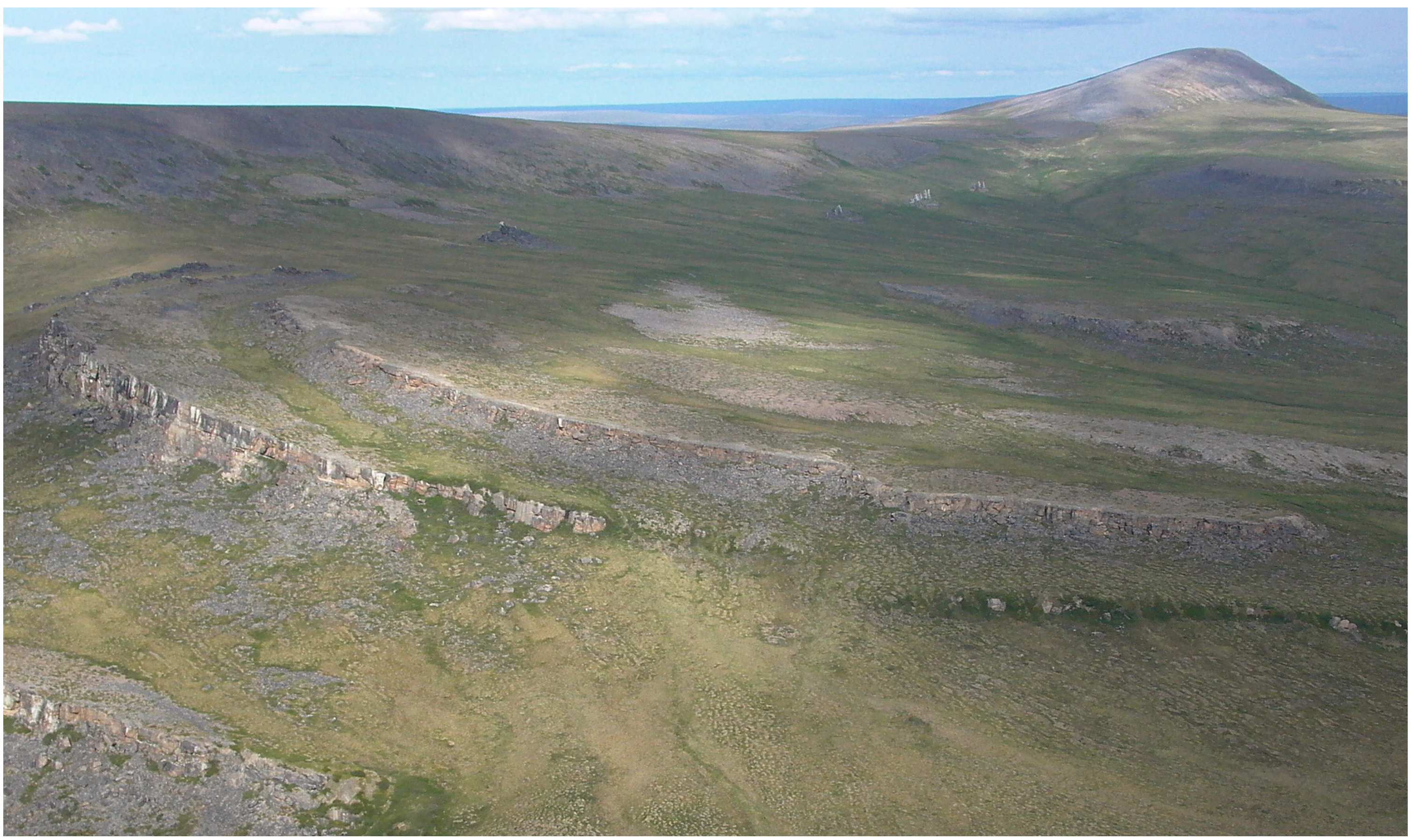
Examination of New Analytic Technologies with Results of Investigation on Drill Samples, North Slope, Alaska

Presenters:
Kurt J. Johnson, Ramil Ahmadov,
Shuvajit Bhattacharya, Dave Browning, Robert Chelak,
KD Derr, Brigette A. Martini, and Michael Smith



Alaska Geological Society – *Connecting the past to the future*
Art Banet, *President* Steve Carhart, *President-Elect*

Alaska Division of Geological & Geophysical Surveys Geologic Materials Center

TECHNICAL BREAKOUT SESSION: EXAMINATION OF NEW TECHNOLOGIES AND ASSOCIATED RESULTS FROM ANALYSIS OF SELECTED SAMPLES, NORTH SLOPE, ALASKA

Kurt J. Johnson, Steve Carhart, Art Banet, Ramil Ahmadov, Shuvajit Bhattacharya, Dave Browning, Robert Chelak, KD Derr, Brigette A. Martini, and Michael Smith

INTRODUCTION

Innovative advances in analysis offer geologists new cost effective opportunities to address many challenges in the geological sciences. Today's speakers examine establishing multiscale heterogeneity across microscopic to macroscopic rock systems, realizing consistent and rapid logging of rock properties in drill-cores and cuttings, and deciphering valid information from massive and often multi-disciplinary datasets.

Non-destructive hyperspectral scan units from New England Research, Corescan, and Terracore utilize visible to infrared spectra (Visible-Near-Infrared (VNIR; 350-1000nm), Short-Wave Infrared (SWIR; 1000-2500nm), and Long-Wave Infrared (LWIR; 7500-12000nm) to examine petrophysical and geomechanical rock properties. Additionally, with millions of dollars often spent to obtain energy drill-core, degradation of these basically irreplaceable rock samples is a significant problem. A hyperspectral core imaging workstation located at a drill site or local repository can provide immediate archival and baseline data for posterity. Software to integrate hyperspectral results with core descriptions and other analytical data allows for faster dissemination and interpretation of depositional and diagenetic processes.

Modern analytical techniques often generate massive datasets that require the application of machine learning to assist in the interpretation of results. Biodentify provides a probability of hydrocarbon prospectivity for large regions using DNA sequencing techniques on the microbial ecosystem in shallow soil or seabed samples. UAA professor Dr. Bhattacharya employs advanced machine learning and geostatistical algorithms for facies, fracture, and rock property classification, prediction, and modeling. Zeiss researchers use a supervised machine learning algorithms to classify core images of varying levels of heterogeneity into different rock types and to automate mineralogical analysis with optical petrography.

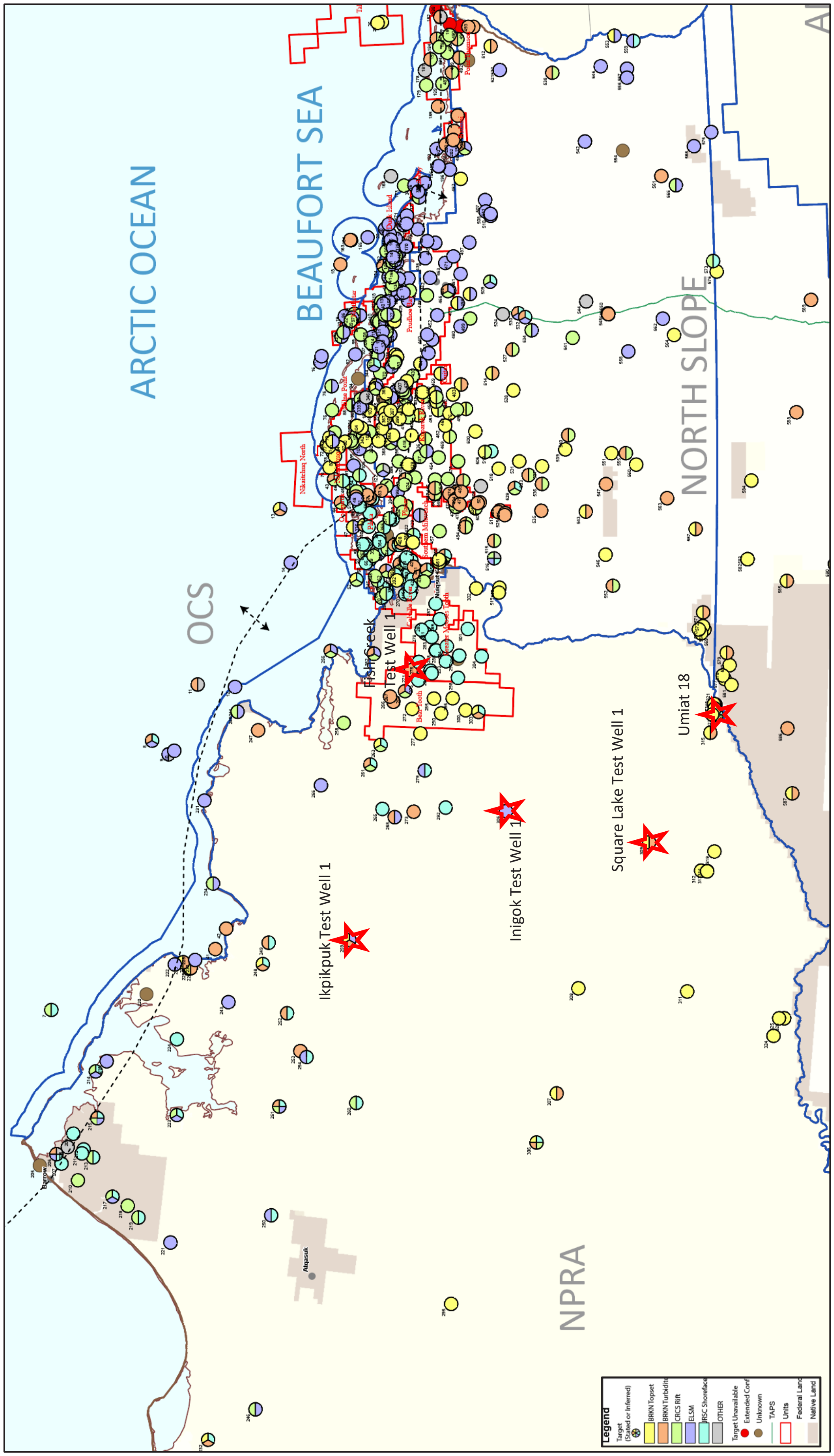
In connection with the 2019 Alaska Oil & Gas Association (AOGA) Conference, the Alaska Geological Materials Center (GMC) hosts a technical breakout session utilizing core, cuttings, and chips from five wells (Umiat 18, Square Lake Test Well 1, Fish Creek Test Well 1, Inigok Test Well 1, and Ikpikpuk Test Well 1) to examine rock characteristics in the Nanushuk, Torok, Kingak Shale, Shublik, Ivishak, and Kavik Shale Formations. Presentations at the session will examine results from these NPRA wells to begin to peer in the black box of big data and artificial intelligence and help gauge the opportunities of deep learning versus the perils of deep forgetting.

ACKNOWLEDGEMENTS

We thank Kurt Johnson, Jean Riordan, Harrison Helton, Monika Fleming, Austin Cunningham, and Kjol Johnson of the Alaska Division of Geological & Geophysical Surveys Geologic Materials Center (DGGS GMC) for hosting this workshop, laying out boxes of core, and other staging support. Thanks to Kristen Janssen with DGGS for preparing written materials for public distribution. Our appreciation to Steve Carhart (President-elect) and Art Banet (President) of the Alaska Geological Society for initiating the opportunity for this session with AOGA and for logistical and technical support during the organization of this event. We express thanks to Kara Moriarty, President of AOGA, for adjoining the GMC technical session with the 2019 AOGA conference. Our gratitude is also extended to Caleb Conrad with Baker Hughes, a GE company, for sponsoring lunch.

Core

Map of Exploration Drilling Targets – (Gregersen & Brown, 2019)



Core

Ikpikpuk Test Well 1 | API: 50279200040000
Analysis: Corescan
Depth range: 10,271.5’-10,300.5’ (Shublik Fm.)
10,619’-10,644’ (Fire Creek Siltstone)
11,108’-11,126’ (Kavik Shale)
Interpreted depositional elements: Shublik (distal shelf?); Fire Creek Siltstone (distal shelf); Kavik Shale (distal shelf)
Shublik is composed principally of highly carbonaceous grayish-black shale, chert, and limestone of Triassic age. Fire Creek Siltstone consists primarily of medium dark gray to black thin-bedded to massive siliceous siltstone that is commonly laminated, with minor silty shale and argillaceous sandstone present locally. Mud lumps, worm trails, and clay ironstone concretions are common. Age is Early Triassic based on ammonites of Romunderi Zone (Smithian) age. Kavik Shale consists of thin-bedded, laminated, silty shale and siltstone with few interbedded sandstones of Early Triassic age. Geolex (2019).

Fish Creek Test Well 1 | API: 50103200090000
Analysis: Zeiss
Depth range: 5480.65’–5515’ (Torok Fm.)
Interpreted depositional elements: Distal shelf.
The USN Fish Creek Well is a historic well which was drilled near an oil seep and found oil in the Nanushuk and Torok sands. The core presented at the breakout session is from Torok turbidite sands which are currently being developed on the coastal plain, but have been cited as having billion barrel+ potential resources. The turbidite sands at the Fish Creek well are ponded turbidites reported to have bailed straw-colored oil, not unlike the high-gravity oils found in parts of the National Petroleum Reserve to date in recent exploration of upper Jurassic sands

Inigok Test Well 1 | API: 50279200030000
Analysis: Corescan
Depth range: 10999’-11008’ (Kingak Shale)
11704’-11714’ (Kingak Shale)
12273’-12283’ (Shublik Fm.)
12500’-12503’ (Fire Creek Siltstone)
12709’-12719’ (Fire Creek Siltstone)
Interpreted depositional elements: Kingak (outer shelf to slope); Shublik (distal shelf); Fire Creek (distal shelf)
Kingak Shale is confined to black shales containing fauna of Early Jurassic age. Is about 4000 ft thick (Geolex, 2019). See above well for other rock unit descriptions.

Square Lake Well 1 | API: 50119100070000
Analysis: Baker Hughes
Depth range: 1,841’–2,040’ (Nanushuk Fm.)
Interpreted depositional elements: Shoreface/delta-front, distributary mouth bar, interdistributary bay, crevasse delta(?). Cretaceous strata in anticline defined on seismic data. No commercial shows of oil were found in Square Lake Test Well 1, but some moderate to strong blows of gas were produced from sandstone beds between 1,600 and 1,900 feet. Collins (1959).

Umiat 18 | API: 50287200280000
Analysis: New England Research
Depth range: 760’–797.9’ (Nanushuk Fm.)
Analysis: Terracore
Depth range: 841.9’–893.9’ (Nanushuk Fm.)
Interpreted depositional elements: Proximal prodelta, distributary mouthbar, distal distributary channel(?). Umiat 18 is a recently-drilled well from one of the first oil discoveries on the Alaska North Slope. The reservoir is a shore face sand and the fluid is about 40 API gravity. Correlative Nanushuk shore face sands on the coastal plain of the North Slope are recently identified highly prospective reservoir objectives.

Abstracts

University of Alaska Anchorage | Shuvajit Bhattacharya, PhD, Assistant Professor[1]

Integration of Tax-Credit 3D Seismic, Wells, and Core Data for a Better Understanding of the Nanushuk-Torok Reservoirs

Exploration of the Cretaceous sandstone reservoirs in the Nanushuk and Torok formations on the North Slope of Alaska is a hot topic and presents opportunities to the oil and gas community because of their shallow depth, vast extent, and scope of development, etc. The consecutive discoveries of the hydrocarbon reservoirs in the Nanushuk and Torok formations by Repsol, Armstrong, and ConocoPhillips in 2015, 2016, and 2017 have only reconfirmed the presence of the vast recoverable resources present at shallow depth on the North Slope, which needs detailed geologic, geophysical, and petrophysical characterization. The goal of the project was to characterize the Nanushuk and Torok formations integrating multiple 3D seismic surveys, well-log, and core (regular poro-perm and micro-CT scan) data. In this study, a top-down approach was used to identify the potential reservoirs using the 3D seismic data at the regional scale followed by well-logs and core data at the well and micrometer scales.

The preliminary results and discussions from the study can be summarized as the following:

- The Nanushuk Formation is expressed as topset reflections, whereas the Torok Formation is expressed as foreset and bottomset on the seismic data.
- Seismic-attribute-assisted mapping revealed the presence of prograding shelf-edges, feeder channels, and basin-floor fans, all with significant amplitude anomalies. The shelf-edges continue for 10s–100s of miles. Advanced seismic attributes such as coherent energy, convergence, and Sobel-filter similarity were significantly useful.
- The internal character of these formations delineated by well-logs shows their vertical heterogeneity. The Torok Formation is highly heterogeneous and petrophysically complex, compared to the Nanushuk Formation. Identification of the reservoirs in the Torok can be challenging at times due to the presence of a special type of clay and suppressed resistivity readings on well-logs.
- Based on the core-plugs, the porosity and permeability values in these formations range from 5% to 35% and 0.1 mD to 1,000 mD, respectively. This is another indication of the reservoir heterogeneity.
- Advanced petrophysical inversion modeling calibrated to core data can be used for facies clustering and identifying the best zone for targeting.
- The results from the available petrophysical data show that only a few zones in the same parasequence in these formations are oil-saturated. This will have implications on reservoir estimates, targeting, and field development in the future.
- Rock-physics-based Vp/Vs ratio is a good indicator of hydrocarbon-bearing sand in these formations. This indirect technique can be useful when enough core samples are not present. However, cautions must be taken before interpreting and interpolating this data.
- Micro-CT ("computed tomography") scan results show the variations in pore size, lithic grains, fractures, and anisotropy in the Nanushuk and Torok formations at micrometer scale (10^{-6} meter). These results will be significantly useful to understand the reservoir compartmentalization better and estimate effective porosity and hydrocarbon volume with less uncertainty.

[1]Dr. Shuvajit Bhattacharya, Department of Geological Sciences, University of Alaska Anchorage, Sbhattacharya3@alaska.edu

New England Research, Inc | Ramil Ahmadov, PhD, Principal Scientist

Automatic Fine-Scale Scanning of Nanushuk Formation for Experimentally Derived Rock Properties

Ramil S. Ahmadov and Gregory N. Boitnott

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 mm) as well as data and analysis of 40ft core interval of Nanushuk Formation.

Introduction

AutoScan (figure 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.

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.

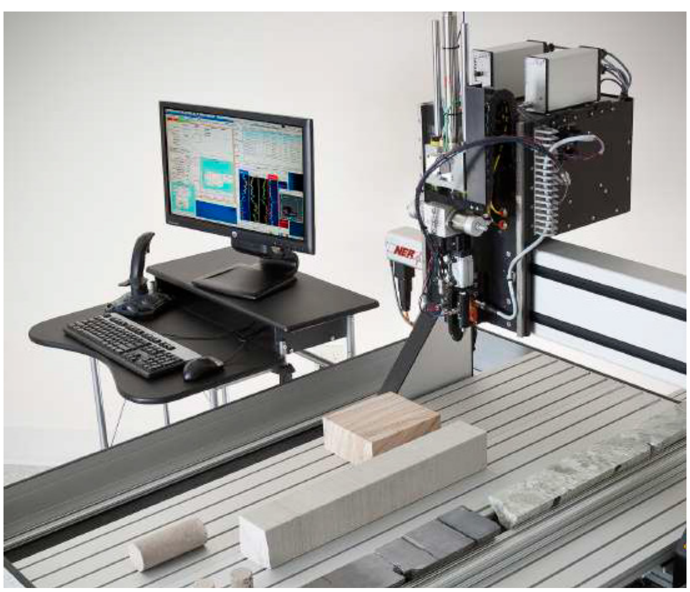


Figure 1. AutoScan—robotically-controlled gantry system for physical property measurements of several different types of core.

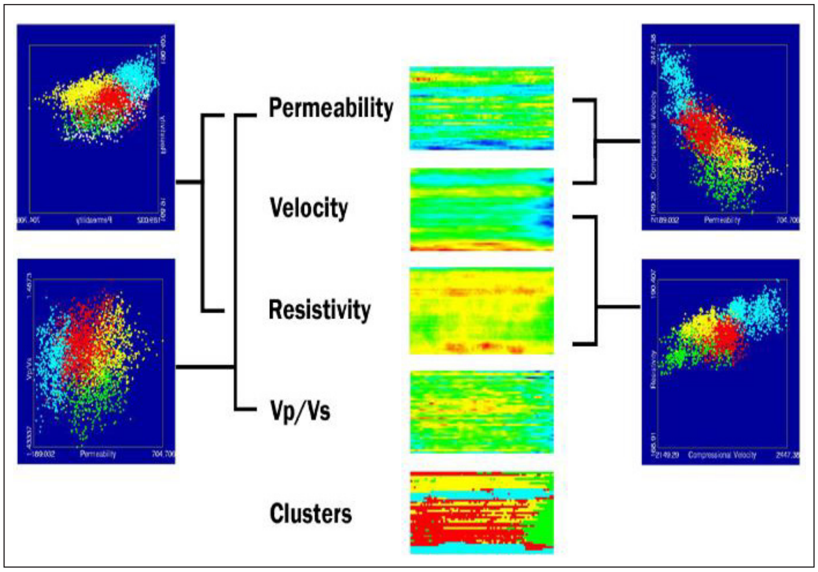


Figure 2. Geostatistical cluster analysis is used to find regions of the sample that are petrophysically similar.

Examples

The Nanushuk Formation is a regressive succession capped by thinner transgressive deposits in its uppermost part. Seismic and outcrop data demonstrate the existence of lowstand erosion surfaces across which shallow and marginal-marine facies are juxtaposed on deeper water facies. A 40-ft section of slabbed core from Nanushuk Formation composed of primarily sandstones and shales was analyzed and measured at 5 mm-scale to quantify heterogeneity in sonic velocities, FTIR, permeability, and mechanical properties (Young's Modulus). The measurements were then compared and complemented to/with more conventionally derived triple-combo of Gamma Ray, Density, and Resisitiity (wireline logging) measurements (figure 3).

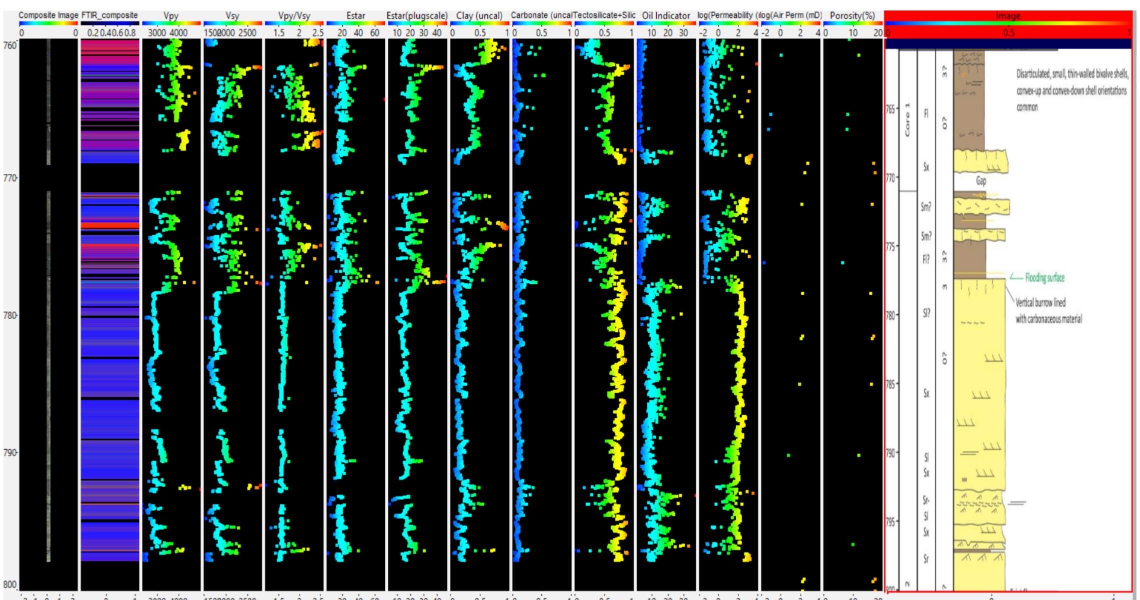


Figure 3. First 12 columns are 40-ft interval of Nanushuk Fm. Analyzed by AutoScan at 5 mm scale, last three columns are from publication by LePain and others, 2018.

Conclusions

The combination of fast and non-destructive physical property measurement platorm 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. The wireline-log resolution data (6-inch resolution) is enriched by adding sub-wireline log resolution (5-mm resolution data) AutoScan data.

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LePain, D.L., Decker, P.L., and Helmold, K.P., 2018, Brookian Core Workshop: Depositional setting potential reservoir facies, and reservoir quality in the Nanushuk Formation (Albian-Cenomanian), North Slope, Alaska: Alaska Division of Geological & Geophysical Surveys Miscellaneous Publication 166, 58 p.

Hyperspectral Core Imaging: Applications in Unravelling Deposit and Reservoir Mineralogy

Dave Browning[1], Paul Linton[1], Phil Harris[1], Chris Sherry[1]

Hyperspectral core imaging is a passive and non-destructive spectroscopic method for identifying and mapping mineralogy in drill-cores and cuttings. Hyperspectral data is available across the Visible-Near-Infrared (VNIR; 350-1000nm), Short-Wave Infrared (SWIR;1000-2500nm), and Long-Wave Infrared (LWIR; 7500-12000nm) regions. The information obtained allows for representative quantification of mineralogy across intervals, providing a reliable, consistent and objective record that is directly applicable to reservoir characterization. Hyperspectral core imaging also allows for the observation of mineralogical and textural properties which are not visually detectable, such as chemistry changes and grain size detection (i.e. sediment vs. cement). The rich dataset provided by hyperspectral imaging provides insight into conventional and unconventional resources, aiding the geologists in the understanding of their reservoir. The spectral data is collected by utilizing a core imaging workstation that combines a long-wave infrared (LWIR) hyperspectral camera with a SWIR hyperspectral camera and a high resolution RGB line scan camera. Several case studies will be presented demonstrating the ability to detect key mineralogical information with direct applications to sedimentary and sequence stratigraphic studies through the direct detection of minerals, mineral chemistry, and mineral particle size. Included in these case studies will be new results from the Nanushuk Formation.

[1]TerraCore, Reno, NV

Integration of Continuous Hyperspectral Mineralogy with Fine-Scale Geochemistry and Micro-Facies Analysis in the Triassic Shublik Formation

Katherine J. Whidden[1], Justin E. Birdwell[1], Julie A. Dumoulin[2], Lionel C. Fonteneau[3], and Brigette A. Martini[4]

As part of a much larger USGS core imaging initiative (~21,000 ft. of scanned rock core and other samples) out of the Energy, Minerals and Crustal Geochemistry and Geophysics Science Centers, core intervals from four Alaskan North Slope wells were scanned including Phoenix-Prospect-1, Ikpikpuk-1, 1-Inigok, and 1-North-Inigok (figure 1). The scanned and analyzed half of the cores presented are housed within the USGS Core Research Center (CRC) at the Denver, Colorado Federal Center. However, the other half of the Ikpikpuk, Inigok, and North Inigok cores reside in the Geological Materials Center (GMC) in Anchorage, Alaska and are referenced for comparison within this presentation.

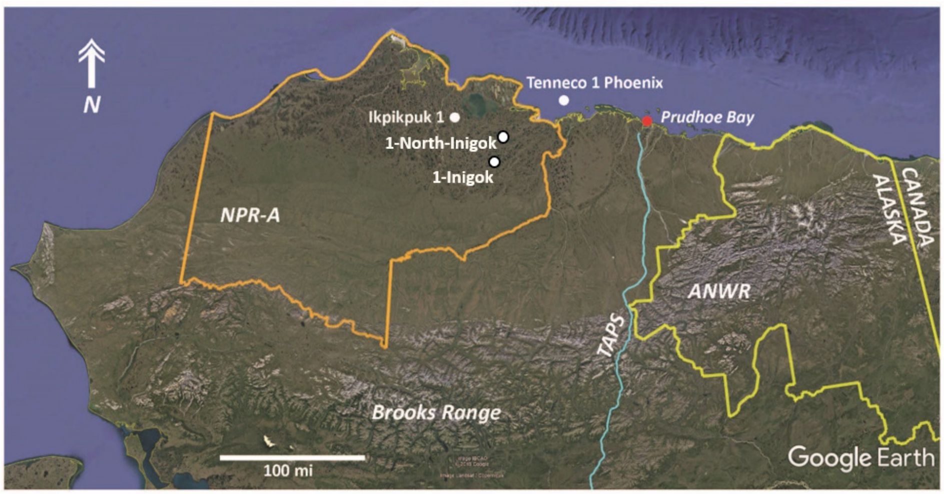

Figure 1. Location of the four Alaskan wells scanned with the Corescan HCI-3 system as part of the larger USGS Hyperspectral Core Imaging studies.

The Middle–Late Triassic Shublik Formation is an organic-rich heterogeneous carbonate-siliciclastic-phosphatic unit that generated much of the oil in the Prudhoe Bay field and other hydrocarbon accumulations in northern Alaska. A large dataset, including total organic carbon (TOC), X-ray diffraction (XRD), X-ray fluorescence (XRF) and inductively coupled plasma–mass spectrometry (ICP-MS) measurements, have been built from core and outcrop samples of the Shublik, with a focus on the organic-rich intervals. In addition, four core intervals from the Shublik were analyzed using the Corescan Hyperspectral Core Imaging-3 (HCI-3) system in the reflected visible, near-infrared, and shortwave-infrared range (figure 2). The HCI-3 continuously images rock material with digital colour photography (50µm spatial resolution), imaging spectrometers (510 bands at ~3.8nm Full-Width Half Max [FWHM] across 450–2500nm at 500µm spatial resolution and an average Signal-to-Noise Ratio [SNR] of 2000:1) and laser profiler (20µm vertical and 200µm spatial resolution). At approximately 200,000 pixels/m (~60,000 pixels/ft) of core material, the scanned USGS Alaskan North Slope wells represent a collection of more than 39 million spectral signatures and corresponding mineralogical and compositional information. Integration of the hyperspectral results with core descriptions, microfacies interpretations, and analytical data is being used to decipher mudstone depositional and diagenetic processes.

Petrographic analysis of Late Triassic organic-rich intervals within the Shublik suggests that the main microfacies is a laminated bioclastic wackestone/packstone that was episodically disrupted by energetic events (EEs) of variable intensity. These EEs produced transitional and sparry calcite bioclastic wackestone/packstone intervals, depending on the depth of sediment column disturbance. By using hyperspectral imaging data from the Ikpikpuk-1 core, individual distribution maps for minerals of interest have been generated and corroborate the microfacies interpretations. These maps also illustrate small-scale vertical changes in mineralogy. The laminated bioclastic wackestone/packstone intervals contain less calcite

[1]U.S. Geological Survey, Central Energy Resources Science Center, Denver, CO
[2]U.S. Geological Survey, Alaska Science Center, Anchorage, AK
[3]Corescan Pty Ltd, Perth, WA, Australia
[4]Corescan, Vancouver, BC, Canada

than in adjacent sparry bioclastic wackestone/packstone intervals. The calcite in these laminated intervals is more iron-rich. This interpretation suggests that lower iron concentrations should be expected in the disrupted intervals than in nearby laminated intervals. Textural features are also enhanced in the hyperspectral images relative to visual description of the cores by combining the extraction of the average reflectance in the visible part of the electromagnetic spectrum and the depth of the main carbonate-related feature belonging to calcite. Examples noted in the enhanced imagery include low-angle features, calcite grain-size, and the size, shape, and orientation of phosphatic nodules. This enhancement is being used to differentiate laminated from sparry bioclastic wackestone/packstone-rich intervals and provides a more comprehensive assessment of the microfacies than is practical by thin-section analysis.

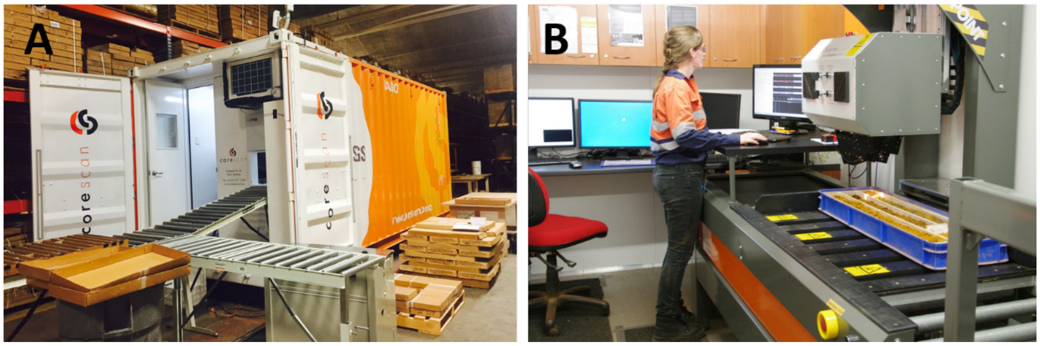

Figure 2A. Fully mobile Corescan laboratory deployed inside of the USGS-CRC. **2B.** Interior of Corescan laboratory with imaging system and computing infrastructure.

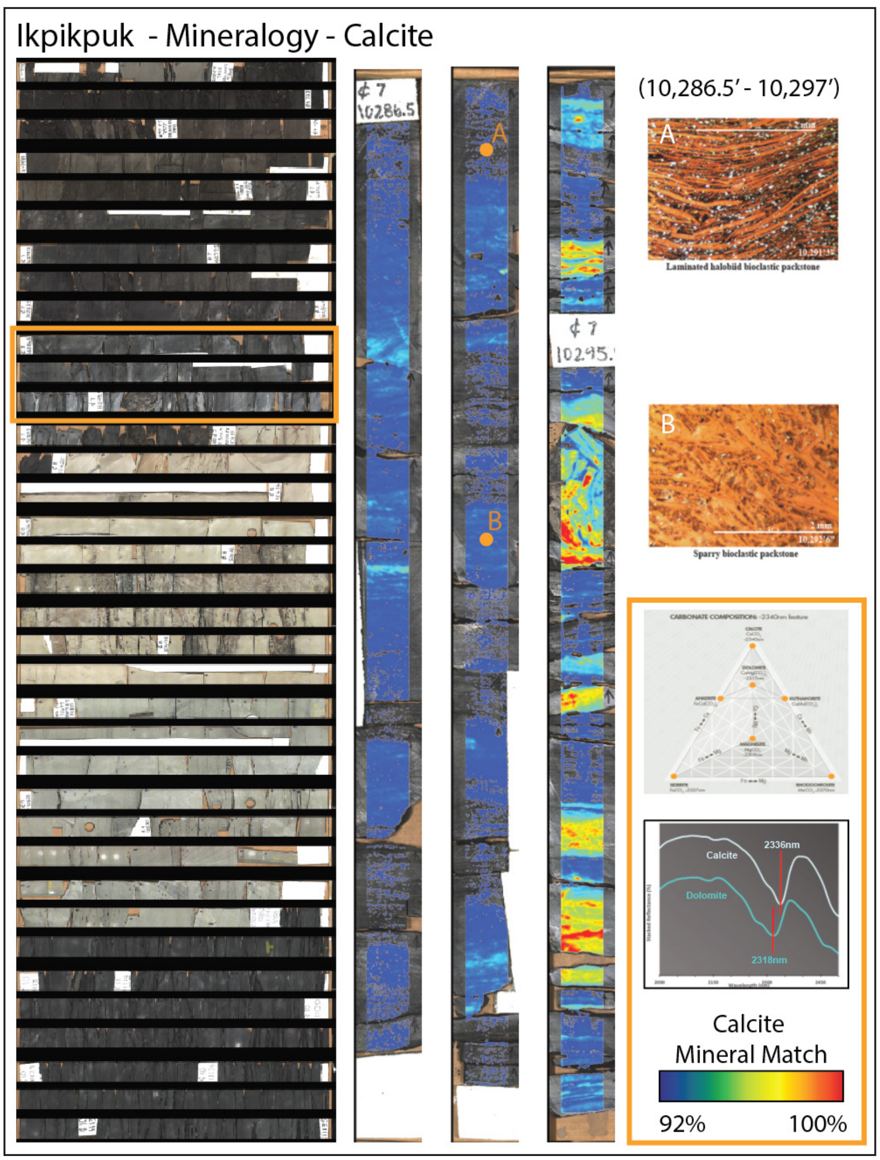

Figure 3. Far left: Scanned core intervals from the Ikpikpuk-1 well (50um Corescan imagery); non-continuous intervals with depth in the down-direction from 7,141 ft. to 11,135 ft. Middle images are 50um Corescan photos with overlays of spatial Calcite distribution measured from Corescan hyperspectral imagery (where red represents a ~100 percent match to USGS library spectra of calcite and blue represents a 92 percent match to calcite library spectra; shown in grey plot at far right; blue areas also represent areas of mixing with other mineralogy). The carbonate ternary diagram outlines other common carbonate species available for mapping using hyperspectral imagery. Upper right images are thin-sections that correlate to the letters shown on the core imagery.

Biodentify | Robert Chelak[1]

Predicting Potential Reservoirs in Reservoir Plays by DNA Fingerprinting and Machine Learning

Biodentify is unlike any other company in the industry as it uses new DNA analytical methods and advanced machine learning algorithms to identify potential hydrocarbon reservoirs from near surface soil samples.

The company's technology is borrowed from a still emerging medical science breakthrough that uses saliva to test for tumors as opposed to a much more invasive biopsy. In looking for alternative uses, it was thought the same process is used to predict oil and gas deposits based on microbial reactions to micro-seepages of gas molecules.

This presentation will present a method to generate a >70 percent accurate predictive map of potential hydrocarbon locations in reservoir prior to drilling. It indicates where to drill, and where not to drill. The approach uses DNA analysis of shallow soil samples, to derive information on the mix of microbial species in the samples. Using a database to correlate DNA in soil samples and production data of earlier drilled areas, the new DNA fingerprint is an indicator of the presence of vertical micro seepage to the surface from hydrocarbon accumulations in the subsurface.

First technological break-through: DNA 'fingerprinting', biotechnology. The occurrence of vertical upward micro-seepage has been known for decades, but the microbial life is much more complicated than just a few species that were known to be hydrocarbon oxidizing bacteria. It is necessary to determine the complex composition of microbes, not only those that flourish at micro-seepage, but also those that are eliminated and are therefore found in reduced concentrations above hydrocarbons. Recent developments in DNA analysis techniques have made this complex and previously expensive problem efficiently and economically solvable.

Second technological break-through: Big data, machine learning, supercomputing. The millions of microbes counted in thousands of soil samples by applying 16SrDNA 'fingerprinting' techniques create terabytes of data that must be correlated with the presence of hydrocarbons. This is a huge mathematical and computational big data problem. Advancements in machine learning applications together with parallel computing (Hadoop in the cloud, GPU) have made it possible to construct robust and reliable predictive DNA based models for hydrocarbon potential locations.

The combination of both technologies will be presented in combination with two case studies: 1) A validation case in the Haynesville shale, an area with known production data, and 2) two areas in the Netherlands where the prospectivity of two shale formations was estimated.

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[1]Robert is an accredited Professional Geoscientist in Texas, and graduated from the University of Alberta with a Bachelor's degree in Geology and Cartography. He has 25 years of experience in the oil and gas industry working for a major oil and gas operator, software development companies, consulting services, that all dealt with geology, geophysics, modeling, new innovations. His growth and experience over the years has allowed him to excel in business development, leading teams, project management, product development, marketing, and implementation of strategic business transformations and innovations.

Carl Zeiss Microscopy, LLC | KD Derr, EM/XRM Specialist

Pore to Core Scale Analysis of Subsurface Flow

1. Multiscale and in Situ Digital Core Analysis

Fluid flow in porous media is dominated by processes occurring at the scale of the microscopic tortuous pathways through the fluid flows and in which the fluids are hosted. The last 20 years have seen a step change in our ability to characterize and examine such flow at the scale at which these physical processes occur, with pore scale imaging and modelling being transformed from a primarily academic pursuit used to examine fundamental processes associated with transport and displacement, to a fully-fledged industrial service industry, routinely used to by the oil industry to predict flow and transport properties of subsurface samples [1]. While many advances have been made, significant challenges remain, particularly in the areas of process and scale.

Frequently subsurface flow is governed by multiphysical processes which are poorly understood and parameterized in real systems. We can begin to address this “problem of process” by using recent technological advances to examine multiphase flow processes experimentally in situ at the pore scale [2,3,4]. The second principal challenge is that of scale. While techniques exist with sufficient resolution to image fundamental pore structures in a wide range of different systems, frequently this comes at the expense of true subsurface heterogeneity [5]. As such, multiscale techniques must be developed to properly characterize this heterogeneity at a representative scale and then drive higher resolution characterization techniques. In this study we will show how these two challenges can be addressed together in the characterization of wettability distribution in a mixed wet carbonate sample.

A 4” whole core sample of a heterogeneous carbonate was first imaged at low resolutions (33μm voxel size) across its entire width using a large field of view Flat Panel detector in the Zeiss Versa X-ray microscope. This initial scan showed prominent heterogeneity on the cm length scale. This heterogeneity was quantitatively characterized by classifying the low resolution image into different petrophysical units (of varying levels of heterogeneity) through the use of a supervised machine learning algorithm [6,7] (figure 1).

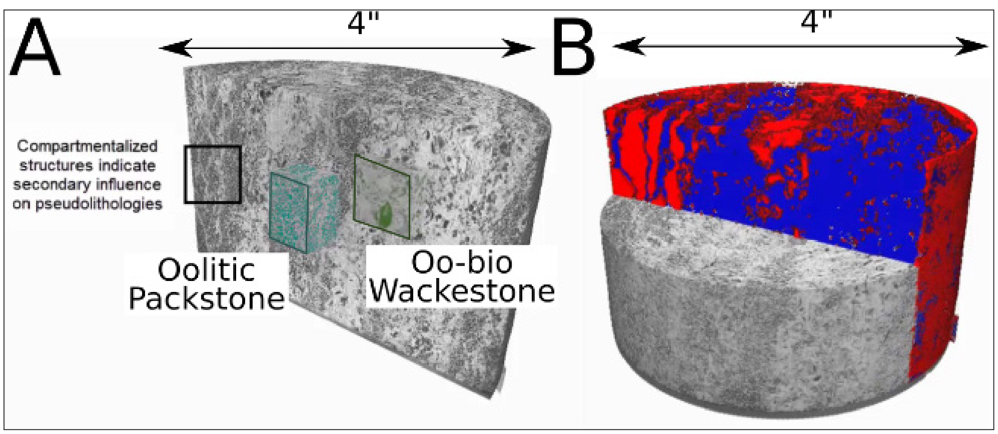

Figure 1. Macroscopic lithological interpretation and classification of heterogeneous carbonate. **A.** Geological analyses defined to micro-lithologies; an oolitic packstone and an oo-bio wackestone. **B.** Supervised machine learning was used to classify the image into different rock types, with the oolitic packstone shown in red and the oo-bio wackestone shown in blue.

This macroscopic classification was used to drive the high resolution coring of the sample, deriving 5mm cores from the both the high and low porosity lithologies. These samples were then mounted into an in situ flow apparatus within the X-ray microscope, enabling fluid flow experiments to be conducted on each sample. The samples were first vacuum saturated with brine before the injection of both oil (drainage) and chase brine (imbibition) to establish a residual state, which was then imaged at intermediate (5μm) resolution. These images were then analyzed to locate the three phase contact line, which was then imaged again at high (2μm) resolution. These high resolution images were then used to measure local spatially resolved wettability using the technique outlined in Andrew and others [8], showing that the high porosity lithology was oil wet, whereas the low porosity lithology was water wet.

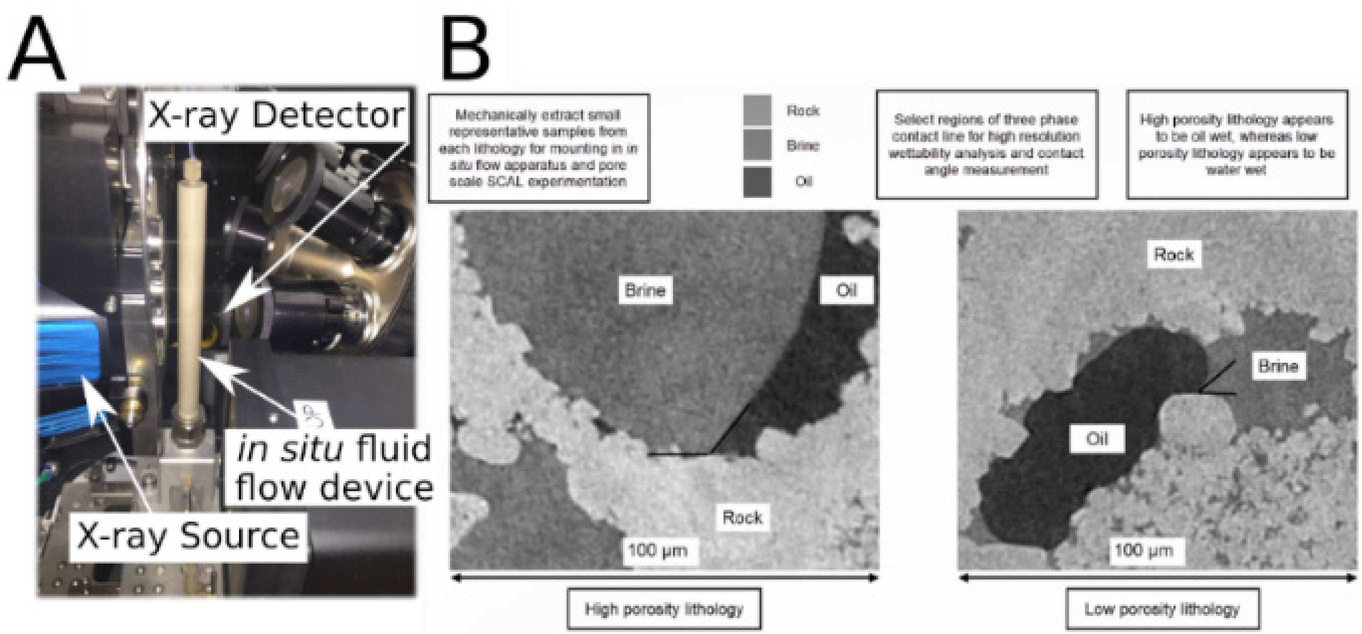

Figure 2. A. Micro-fluidic device used to measure multiphase fluid distribution in situ, in place within the high resolution X-ray microscope. **B.** Multiphase fluid distribution in the high porosity lithology (left) and the low porosity lithology (right). The high porosity lithology was found to be oil wet (oil sitting in corners of large pores and in small pores) and the low porosity lithology was found to be water wet (water sitting in the corner of large pores and in small pores).

Such heterogeneity of behavior can only be understood in the context of the macroscopic lithological heterogeneity of the sample. As heterogeneity was used to drive high resolution sampling, the resulting high resolution behavior can be upscaled back to the whole core scale much more readily, enabling for the first time both pore scale and core scale information to be integrated and analyzed concurrently.

2. Automated Optical Petrography

One of the principal difficulties in pore-scale analysis of reservoir rocks has been that these techniques are challenging to scale and automate. This is usually because the continuous outputs of the imaging techniques must be ultimately classified into discrete phases for subsequent analysis and interpretation. These image outputs carry a variety of artifacts and noise that cause traditional analytical techniques to fail as the images become more complex.

During visual examination, the brain of a trained petrographer, petrophysicist, or mineralogist acts to integrate the rich, potentially multimodal datasets to extract the desired information. Such an approach is challenging to capture and express in a computational form, making microscopy challenging and expensive to scale across the many 1,000s of feet of core required to describe reservoir behavior effectively. Machine learning techniques give us, for the first time, a robust set of tools to capture the complex set of processes involved in analyzing the rich datasets available to microscopic imaging in a way that is computationally scalable to a broad range of samples.

We will show how, by integrating automated mineralogical analysis, through the usage of supervised machine learning tools, with optical petrography, we can automatically extract mineralogical information from traditional cross-polarized light microscopy techniques. Multiple different cross polarization orientations are acquired and spatially registered. These spatially registered datasets become feature vectors for a trained classifier, operating across the entire polarized light space at once (figure 3). This new capability is particularly exciting as optical petrographic techniques are inexpensive and provide rich data about a wide range of reservoir petrophysics and geology.

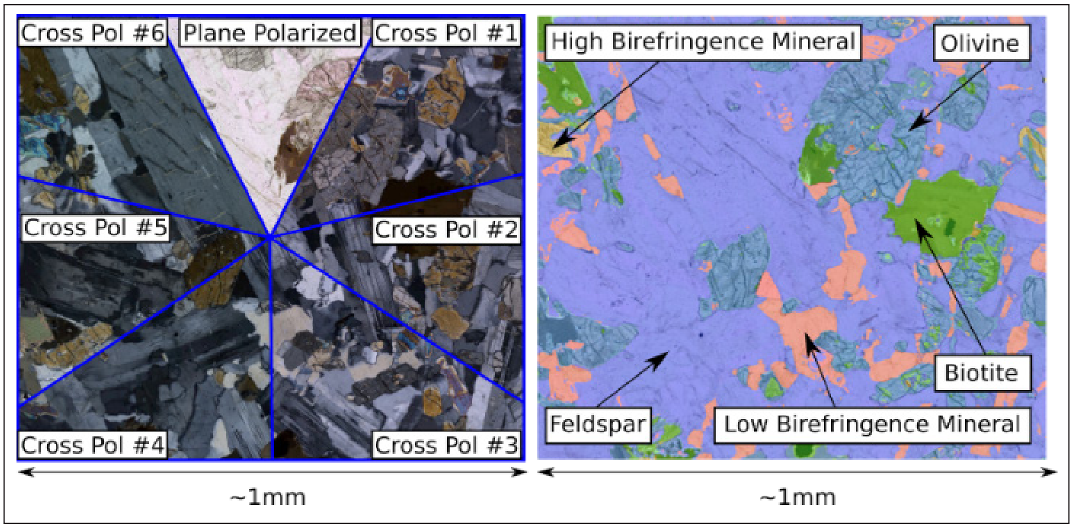

Figure 3. Automated mineral classification using machine learning. Multiple spatially registered cross-polarized datasets are acquired. These are then input into a supervised machine learning based classification system which uniquely identifies each pixel as belonging to a specific mineral.

Once slides have been digitized and segmented using machine learning techniques, they can then be subjected to automated quantitative structural analysis, creating a suite of petrophysically relevant information about the rocks of interest, including porosity, information about the size and shape of pores and grains (figure 4), and even direct predictions of flow and transport properties (like permeability or mercury intrusion capillary pressure (MICP) curves). As the measurement times (and so cost) when using these techniques are low, and they have a strong ability to access structures over (whole core) extended length scales, high density sampling allows for pore-scale analyses to be directly upscaled to the whole core length scale.

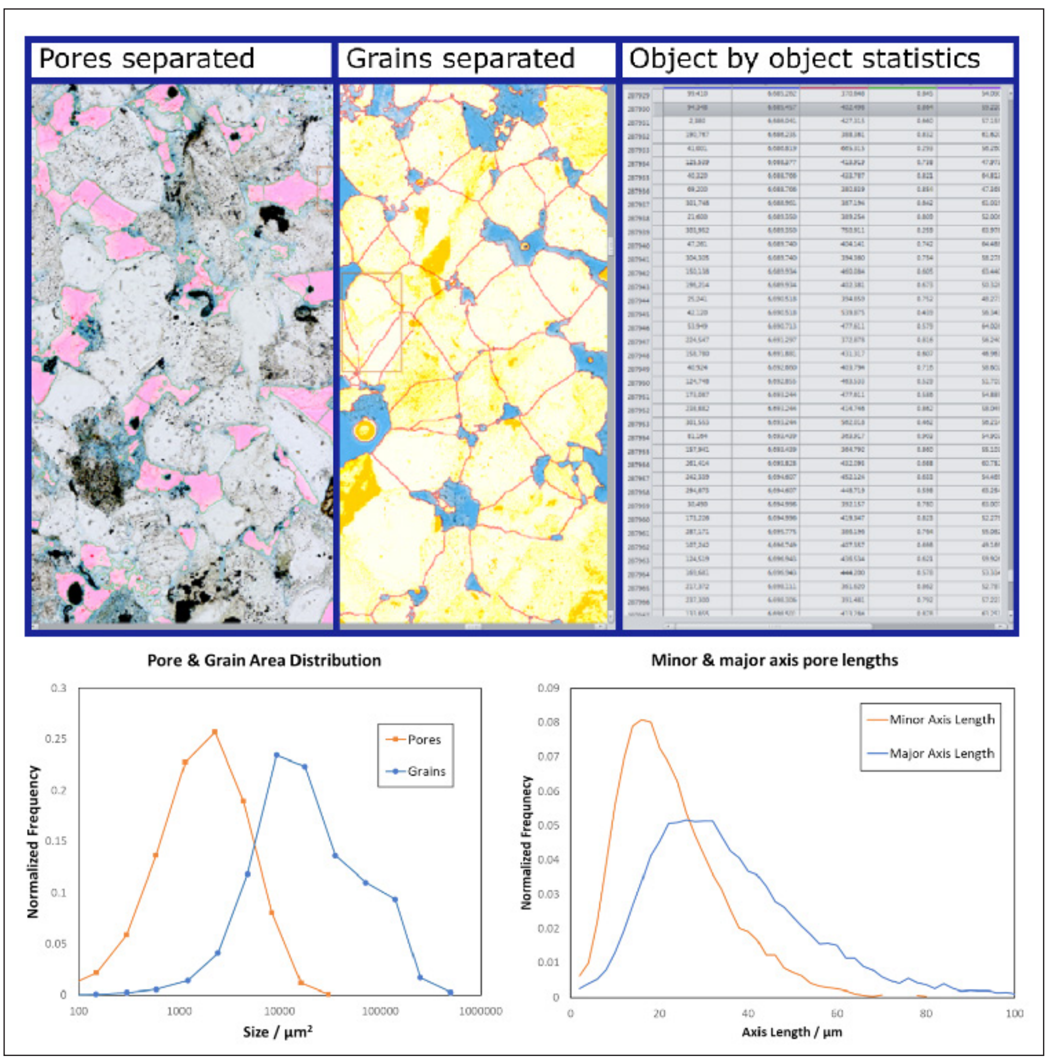

Figure 4. Pore and grain structural analysis of Berea sandstone showing pore and grain separation, object-by-object measurements and the automated reporting of the statistical distribution thereof.

3. Application to Alaska

As well as showcasing a range of results from the ZEISS multiscale rock characterization workflow from samples around the world, we will showcase how these are being applied to Alaskan samples from the Torok Formation. Samples were scanned using X-ray microscopy and segmented with the data being used as an input for pore-scale digital rock simulations of permeability and MICP. Samples were also scanned using high throughput automated petrography, with data analyzed using multi-variant machine learning based segmentation tools, and a pore structural analysis created (figure 5).

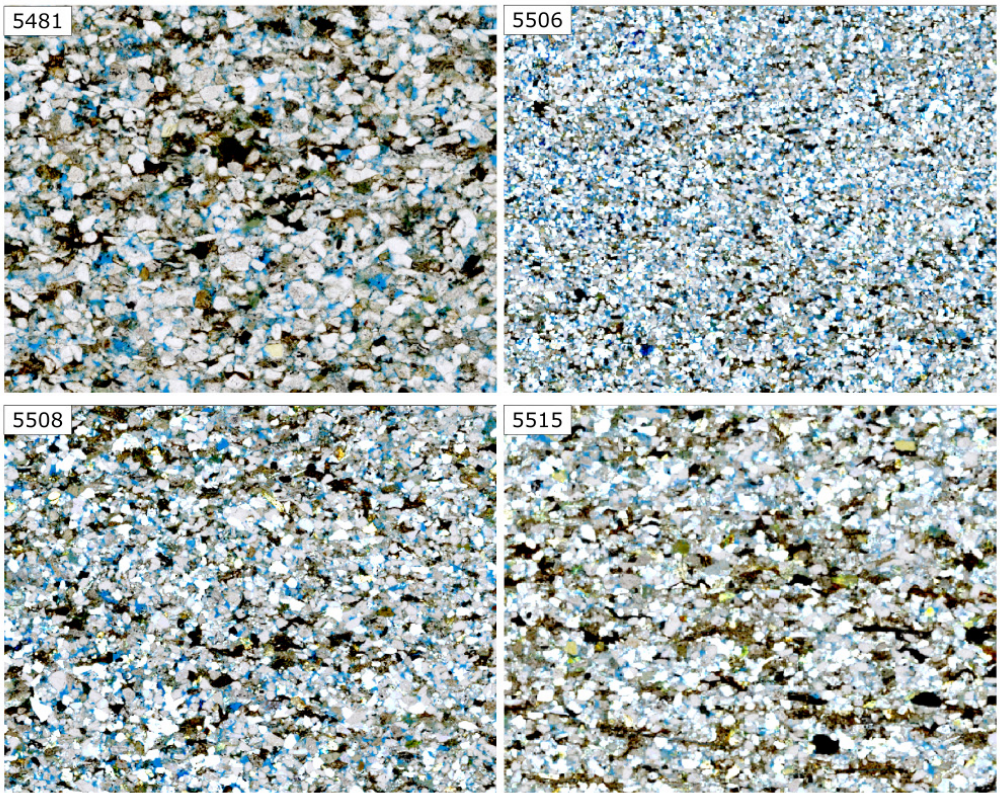

Figure 5. Sequence of high throughput analyses of the Torok Formation through a 34ft section, showing variation in clay percentage and pore/grain size.

Baker Hughes, a GE company | Michael Smith, PhD[1]

Advanced Cuttings Volatiles Analyses for Reservoir and Pay Characterization, and for Petroleum System Characterization. Extracting Value from Drill Cuttings. A Free and Underutilized Drilling By-Product.

The analysis of volatiles from drill cuttings is a breakthrough technology that can determine present day fluid characteristics. The Volatiles Analysis Service (VAS) invented by AHS and distributed by Baker Hughes, a GE company, provides a high value log with no additional logging time that can identify the landing zone and characterize the lateral to enable optimized completion strategies to get the most value out of conventional and unconventional play assets. VAS delivers the occurrence and composition of oil and gas in the cuttings, as well as mechanical strength, permeability, oil saturated water, proximity to pay, and location of potential pay zones and faults. This approach allows for rapid cost effective data integration across well generations for understanding by-passed pay, optimizing landing zones, and petroleum system assessments. These analyses can be performed on both legacy cuttings in storage (often decades old) and from cuttings sealed at the wellsite following a patented approach.

The VAS technology analyzes all extractable volatiles in a sample and is not limited to the analysis of Fluid Inclusions, unlike the other existing technologies in the marketplace. The measurement of volatiles from drill cuttings is by a gentle extraction and analyses technology that utilizes all the volatiles in a cuttings sample using a Cryo Trap Mass Spectrometer (CT/MS) system invented and built at AHS. Volatiles are extracted from each individual sample at two distinct pressures, frozen onto liquid nitrogen (LN^2) traps, and analyzed by allowing the frozen volatiles to sublimate and enter the mass spectrometer according to their sublimation points under high vacuum. This provides a measure of compound separation and quantification like that obtained in Gas Chromatography Mass Spectrometer (GC/MS) systems. However, unlike GC/MS, this unique CT/MS system is non-selective. All volatile compounds that can be extracted and frozen are analyzed. Helium and methane are analyzed prior to beginning to warm the Cryo Trap as they are not frozen.

The practical application of this technology has allowed for VAS to evaluate petroleum system from legacy PDC cuttings with significant cost savings realized against conventional petroleum system analysis. AHS has documented that legacy PDC cuttings typically contain larger amounts of oil and gas within the extremely tight rocks that do not add significantly to production. Good quality oil-charged reservoirs have cuttings that have lost most of their oil and gas due to the drilling process and interaction with the mud system over their transport (usually 1.5 to 2 miles or more), and then being washed and allowed to dry at the surface.

With this insight, VAS can successfully map where the tight and/or charged rocks are in the reservoir. Reservoir rocks adjacent to faults that are oil migration pathways are charged by the oil migration along the fault. Reservoirs at a significant distance to the fault migration pathways are not charged. Oil and gas, including Helium, migrate predominantly into reservoir rocks in the hanging wall above the fault plane. Basinal brines migrating with oil and containing organic acids migrate predominantly into the foot wall below the fault plane. The migration of oil and gas into the fault adjacent reservoirs preserves reservoir quality. Basinal brine and organic acid migration encourage the formation of tight rocks with poor reservoir qualities in the foot wall of these faults. Source rocks near faults can be depleted in oil and gas that has escaped along the faults. These finding has allowed operators to target the high-quality charged reservoirs on their acreage based on VAS results.

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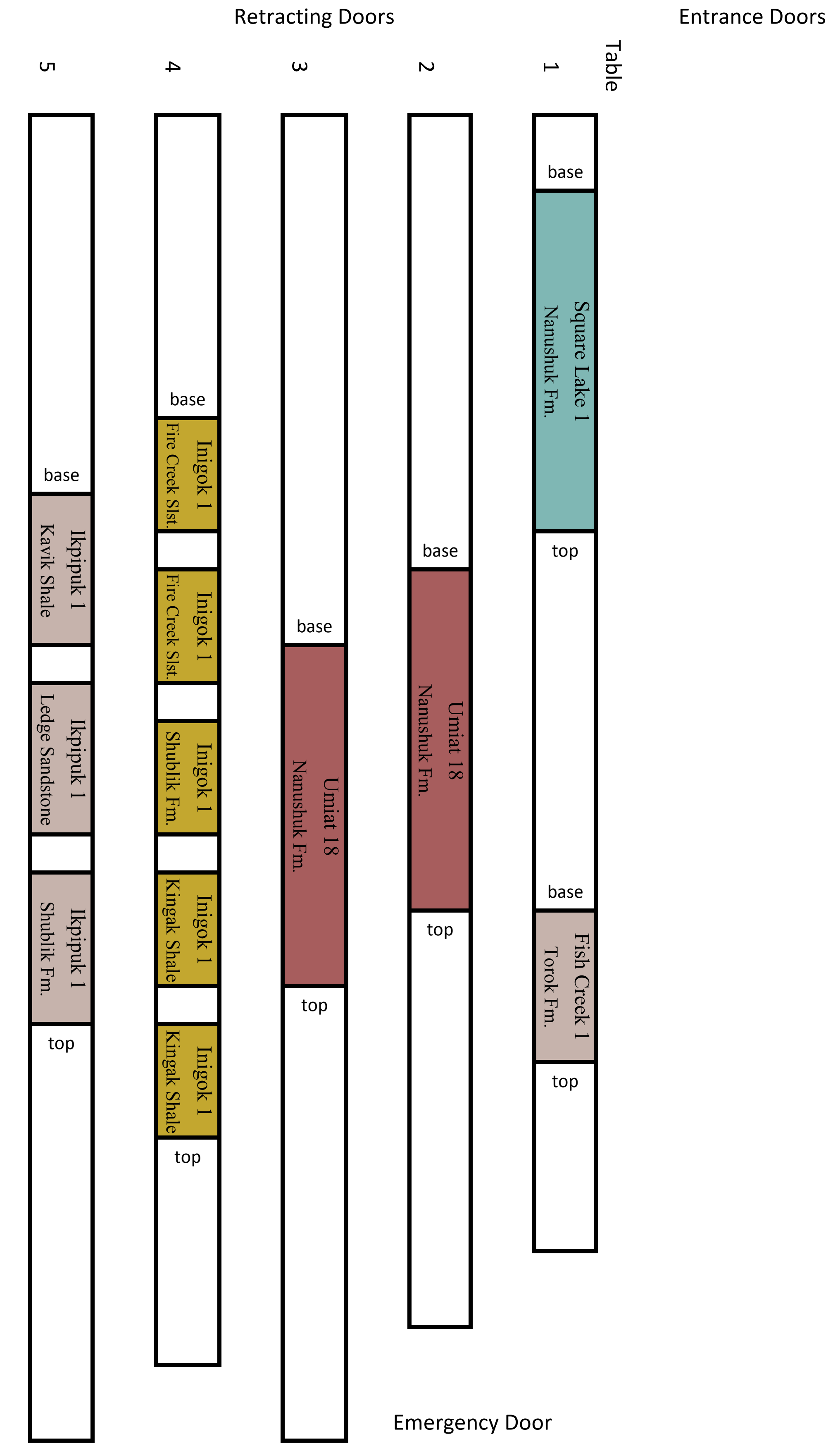
[1]Advanced Hydrocarbon Stratigraphy, Inc, 2931 W21st, Tulsa, OK 74107 | ahstrat@aol.com | 918-671-0355

Core Layout



Retracting Doors
Entrance Doors
Table
1
2
3
4
5
base
Square Lake 1
Nanushuk Fm.
top
base
Fish Creek 1
Torok Fm.
top
base
Umiat 18
Nanushuk Fm.
top
base
Umiat 18
Nanushuk Fm.
top
base
Inigok 1
Fire Creek Slst.
Inigok 1
Fire Creek Slst.
Inigok 1
Shublik Fm.
Inigok 1
Kingak Shale
Inigok 1
Kingak Shale
top
base
Ikpikpuk 1
Kavik Shale
Ikpikpuk 1
Ledge Sandstone
Ikpikpuk 1
Shublik Fm.
top
Emergency Door