London Petrophysical Society

Old Data, New Tricks

How to maximise value from legacy data

Thursday 26th September 2024
Geological Society, Burlington House, London
09:00-17:00 (London GMT+1)

London Petrophysical Society - "Old Data, New Tricks" - Thursday 26 September 2024				
Start Time	End Time	Name	Company	Talk Title
09:00	09:15	Doors Open and Registration		
09:15	09:25	Edwin Wraith	LPS	LPS VP Seminars - Introduction
09:25	10:00	Waclaw Jakubowicz	Hampton Data Services Ltd.	Challenges & solutions in managing 'old' legacy well data
10:00	10:35	Yousef Abu	Sand Injectite Research Group - University of Aberdeen	Core Data: From Research to Digital Innovation
10:35	11:10	Kirsty Hitchen	bp	Leveraging 60 years' worth of legacy well data for CCS site characterisation
11:10	11:40	Break		
11:40	12:15	Alan Johnson	Integrated Petrophysical Solutions	Modern Field Evaluation Using Legacy Log and Core Data
12:15	12:50	Brian Moss	Independent	Some ideas for deriving useful formation evaluation when only the SP and resistivity are available.
12:50	13:25	Paul Hoddinott	Independent	The value of old mercury-injection capillary data (MICP) for new petrophysical interpretations
13:25	14:25	Lunch		
14:25	15:00	Marcus Turner	SLB	Saturation type identification through flowline compressibility changes
15:00	15:35	John Guntoro	ANSA Data Analytics	Automating MFC processes through modularised ML models
15:35	16:10	Romulo Cuevas	ROGII	Autosteering Multiple Horizontal Wells Simultaneously with Machine Learning using Legacy Data from Unconventional Reservoirs. Example from the Eagle Ford Basin.
16:10	16:45	Emily Collett	Halliburton	A Cloud-based Machine Learning Approach for Well Interpretation
16:45	16:55	Jack Willis	LPS	LPS President - Closing Remarks
16:55	Networking Reception in the Library			

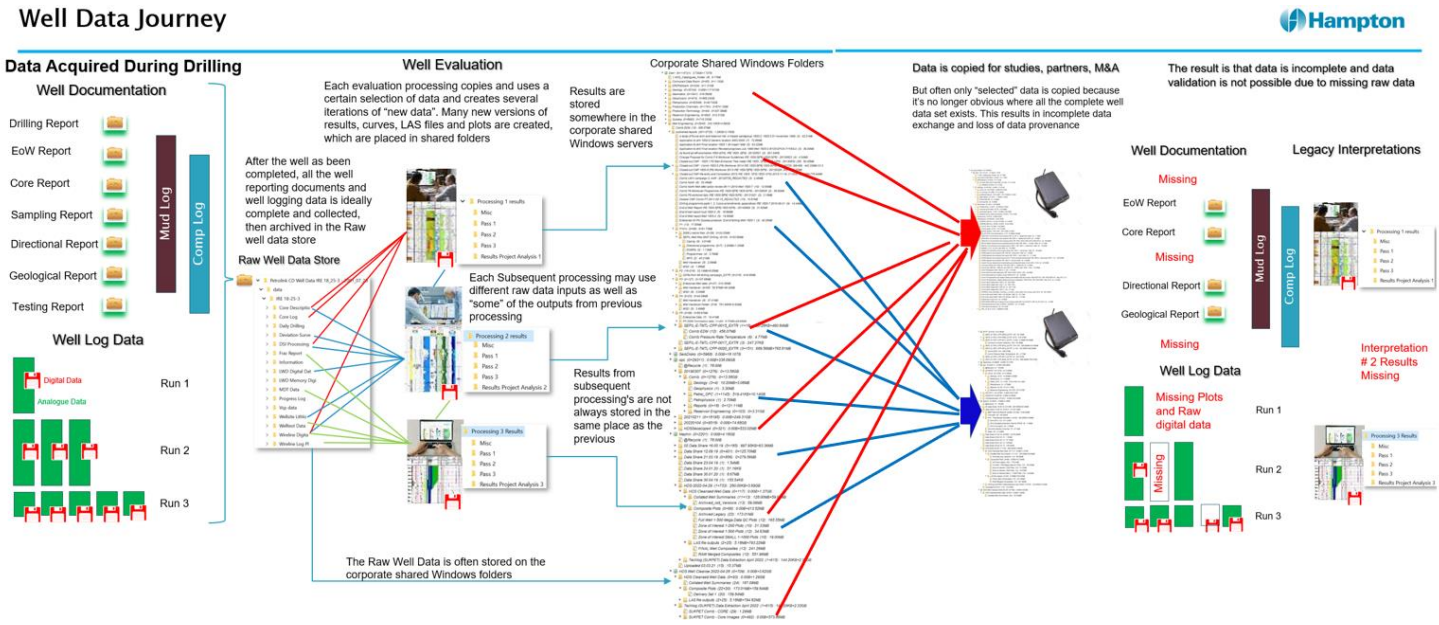
Register via the LPS website: https://lps.org.uk/events/

Challenges & solutions in managing 'old' legacy well data

Waclaw (Wally) Jakubowicz – Hampton Data Services

Old well data by its definition was acquired "sometime ago" and has most likely had many a process and movement applied to it. These processes include multiple copying, separation of individual components of the original complete acquired well data set, fragmentation, renaming of files and curve mnemonics, editing without documentation and loss of key data elements. In addition, all this data is buried in large unstructured file and folders on corporate servers or USB disks.

As a result, when such a data set arrives in front of a the Petrophysicist, it is often incomplete, unstructured and of unknow provenance and quality.



In the paper we show how certain data management & mining processes (Including ML and text analytics) can be used:

- in discovery of the "missing" well data in large unstructured data volumes
- identifying and removing file and curve duplications,
- data & curve gap analysis
- overcoming extensive well aliasing,
- establishing data provenance and the legacy processes applied to them,

In addition, the paper suggests methods and processes for managing and storing the well log curve editing, processing & compositing audit records of the "new process & interpretation" applied by the Petrophysicst to the legacy "old log data".

Waclaw (Wally) Jakubowicz (BSc Geology MSc Geophysics DIC) has spent over four decades in the oil and gas industry. After working for Schlumberger as a wireline engineer, geophysicist and petrophysicist, he went on to be an independent consultant for many clients around the world. In parallel to his geoscience career, Wally has spent the last 30 years in subsurface data and information management. This was largely driven out of the frustration of having to constantly initiate studies with poor quality, incomplete, and unauthenticated data and then struggling to find the necessary supporting critical data needed for an optimal interpretation.

Wally founded Hampton Data Services which offers its own efficient E&P data discovery applications and clean up workflows. These bespoke methodologies use ML, BI rules, and neural networks to create an Automated Virtual Data Management environment to index, classify and spatially link large volumes of unstructured data that are "swimming or submerged in data seas".

Core Data: From Research to Digital Innovation

Yousef Abu Yousef – Data Manager at Sand Injectite Research Group / GeoXtract

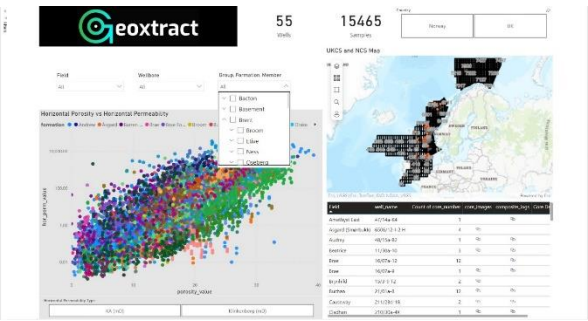
As the demand for digitalization and advanced data management grows in both industry and academia, it becomes crucial to utilize the right tools for data storage, visualization, and analysis. The Sand Injectite Research Group (SIRG) at the University of Aberdeen has developed an extensive core database, which stores raw and interpreted data for 2,699 cored wells, primarily from the UK Continental Shelf (UKCS). This dataset, which includes over 595,000 Conventional Core Analysis (CCA) samples, has undergone rigorous standardization and modification to support petrophysical and reservoir engineering applications.

The database encompasses a wide range of data, including:

- UKCS CCA/Special Core Analysis (SCAL), including porosity, Kh, Kv, grain density, Klinkenberg corrected permeability, overburden corrected permeability and porosity, grainsize and sorting data, formation pressure, and stratigraphic/lithostratigraphic data for 90% of the wells. We have recently included capillary pressure and relative permeability data for those sand injectite wells with SCAL data. Fluid property data and petrographic analysis is also to be added.
- Original and recent (BGS) core images. BGS core images are concatenated into a single report rather than individual photo plate downloads to enable easy data integration.
- Sand injectite field data (published STOIIP, production volumes, creaming curves of HIIP/reserves per field classification, country, reservoir age and more.
- The database is visualized on Power BI - with a GIS enabled dashboard.
- CCA/SCAL data for 100 wells within sand injectite fields from the Norwegian Continental Shelf (NCS), with the aim of including similar data for all 1775 cored wells from NCS by year end 2024.
- We have commenced incorporating core derived lithofacies interpretation of the 185 UKCS cored sand injectite wells, to provide an additional lithofacies classification to the petrophysical parameters, and to provide a standardised facies interpretation/ library. This dataset will be used to create an automated model to characterize the core facies.

Initially developed to assist SIRG's industrial consortium members, this initiative has now evolved into an academic spin-off called **GeoXtract.** We aim to transform the way geological data is accessed and utilized in industry and research. Our ongoing work aims to incorporate advanced data extraction techniques that eliminates the need to spend time on data collection and transformation and more time spent on use of data and analysis.

Example 1: SIRG dashboard with all UKCS cored wells, including well, field and stratigraphic filters



Example 2: GeoXtract dashboard which is currently available online at https://www.geoxtract.com/index.php/powerbi/

Yousef Abu Yousef is the Database Manager of the Sand Injectite Research Group at the University of Aberdeen, where he has been developing a sand injectite-focused core database since 2022. After proving commercial value, Yousef and Matthew Brettle co-founded GeoXtract, an academic spin off aiming to leverage legacy data to develop a pan North Sea subsurface database for geoscientists.

Leveraging 60 years' worth of legacy well data for CCS site characterisation

Kirsty Hitchen - bp

Modern Field Evaluation Using Legacy Log and Core Data

Alan Johnson – Integrated Petrophysical Solutions (IPS) Ltd/Harbour Energy plc

The repurposing of various depleted gas fields in the Southern North Sea for potential CO2 storage has led to the requirement to re-evaluate legacy the data these fields, some dating back to early 1970's, to produce new field models built to modern standards.

The presentation will focus on recent work on several fields in the V Fields complex, originally developed by Conoco UK Ltd but now operated by Harbour Energy plc.

The main focus will be on data from Viking A, which on stream in 1971, but will include some data from surrounding fields for comparison.

The data discussed will cover:

- Routine Core Data – limitations of early reporting and compatibility with more recent data
- Early Resistivity Log Data
    - Porosity Log Data – with no serious issues
    - Resistivity Log Data – Specifically Laterolog 7. Tool issues and Invasion Corrections.
- Reservoir pressure information – pre RFT, using wellbore static surveys.

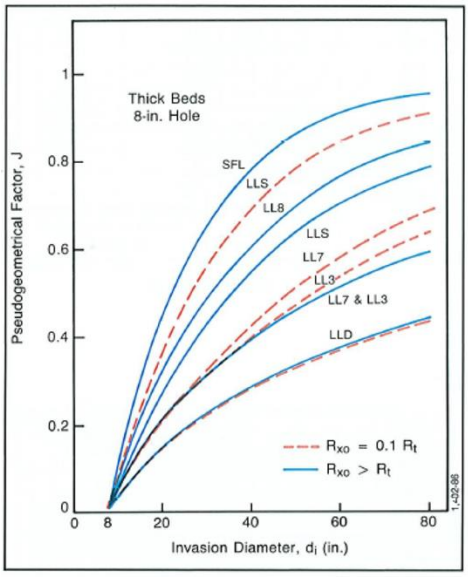


Fig. 7-17—Radial pseudogeometrical factors, fresh muds (solid) and salty muds (dashed).

Schlumberger "Log Interpretation Principles/Application" 1989

Alan Johnson is a Petrophysical Consultant with Interactive Petrophysical Solutions Ltd. (IPS). Until April 2016 he was Principal Petrophysicist with Shell UK in Aberdeen. Prior to joining Shell in 2001, he worked as an independent petrophysical consultant in the UK for several years following a 14-year career with Hamilton Oil (later BHP Petroleum) as a Senior Petrophysicist and Petroleum Engineering Supervisor based in London and Vietnam. He originally started his career Shell in 1974 with a degree in Physics from Aberdeen University; during this early phase of his career he worked in Aberdeen, Abu Dhabi and The Hague, predominantly in petrophysics.

Some ideas for deriving useful formation evaluation when only the SP and resistivity are available

Brian Moss

Spoiler alert: the SP only indirectly gives you porosity.

The author has been working on a project comprising a modest gas accumulation somewhere in the world. The clastic formation is relatively young and comprises likely fluvial sands passing basinwards into shallow marine and on into deeper water turbidites.

Through the 1950s, wells were drilled to basement and gas was discovered in sands that onlapped the basement high. These wells were logged with SP-ES, or SP-IES combinations. Some more recent appraisal wells, drilled within the last decade or two, are logged with triple combo log suites. No cores exist across the structure.

The availability of the data from those later wells was delayed and it was necessary to use the old-style log data in isolation to start to characterise the formations across the structure.

In the absence of specific log response modelling software, the method developed was:

- to consider the formation as a binary system: sand and shale
- use the SP to create a shale profile
- develop a compaction curve that could be deemed to characterise total porosity
- reduce this estimate of PHIT to an estimate of PHIE, on a level-by-level basis, using an empirical formula developed and used with some success in the 1950s in the Gulf of Mexico
- take a rather simplistic view of the resistivity data to derive a first-pass saturation profile in potential reservoir sands.

Validation of the approach in broad terms was possible once the more modern data became available. Parameters were tweaked and satisfactory answers, given the data limitations, were derived.

Similar steps can be applied to sparse LWD suites of GR-RES.

In addition to the initial formation evaluation effort, the old-style data were used in a novel way to establish a stratigraphy across the structure. This has stood the test of time in that the later data sets were shown to support the Formation-level stratigraphic subdivisions that came out of the work on the older wells.

Brian MOSS. Retired. 25+ years petrophysical analysis and training experience and 10+ years software development and sales experience. (Worked in Government, in a large consultancy house, as an individual consultant, in a small software company and in a large service company; all preceded by a stint offshore in mud-logging.)

The value of old mercury-injection capillary data (MICP) for new petrophysical interpretations

Paul Hoddinott - Independent

Many historically cored wells acquired SCAL measurements, including Mercury-injection capillary pressure data (MICP), but often these data are not available in digital form and the interpretations have been lost or never passed on to new operators. These old core data can be digitally transcribed from reports and can be invaluable for generating modern integrated interpretations.

MICP measurements include a wealth of data, including porosity and permeability, pore throat radii, and water-equivalent saturations, giving insights into reservoir quality and well deliverability.

The data can also be used to build saturation-height models (SWH) that help answer some petrophysical challenges, including fluid contacts, oil sweep, uncertainty with formation water salinity, low salinity formation waters, and thin bed environments, where resistivity logs do not adequately quantify water saturations.

This talk will also cover the methods of Adams (2016) into building published Saturation-Height models (e.g. Thomeer, Leverett-J, Lambda, Sjkaeveland) in MS Excel, that are reproduceable and auditable. Also, the benefits of sampling old core material to take new MICP measurements to add value to subsurface studies, will be discussed. MICP data can also be potentially used for other future applications, such as better understanding reservoirs for CO2 injection and CCS.

Real-time Flowline Compressibility Changes as a Catalyst for Advanced Petrophysical Interpretation in Thin-Bedded Pay

Marcus Turner - slb

This paper introduces a novel approach for saturation type identification through real-time monitoring of flowline compressibility changes during pretest operations. This method enhances petrophysical interpretation by identifying fluid types, particularly gas, in interbedded sandstone and shale formations. Traditional petrophysical methods often misidentify gas as oil due to shoulder bed effects, leading to incorrect reservoir management decisions. By observing compressibility changes during decompression and recompression phases, this technique flags gas ingress into the flowline, indicating the presence of mobile gas. High-resolution density measurements and advanced evaluation techniques further refine the petrophysical interpretation, resulting in more accurate identification of pay zones and improved well completion decisions.

The novel approach has been used while drilling and to re-evaluate ambiguous formations in historical wells to retrospectively improve reservoir model and reservoir management.

Interpreting fluid types in interbedded sandstone and shale formations poses significant challenges in petrophysical analysis. The neutron density crossover effect, often used to identify gas, can be obscured by shoulder bed effects, leading to misinterpretation of gas as oil. This misidentification impacts the determination of net gas versus oil volumes, which in turn affects completion decisions and reservoir management strategies.

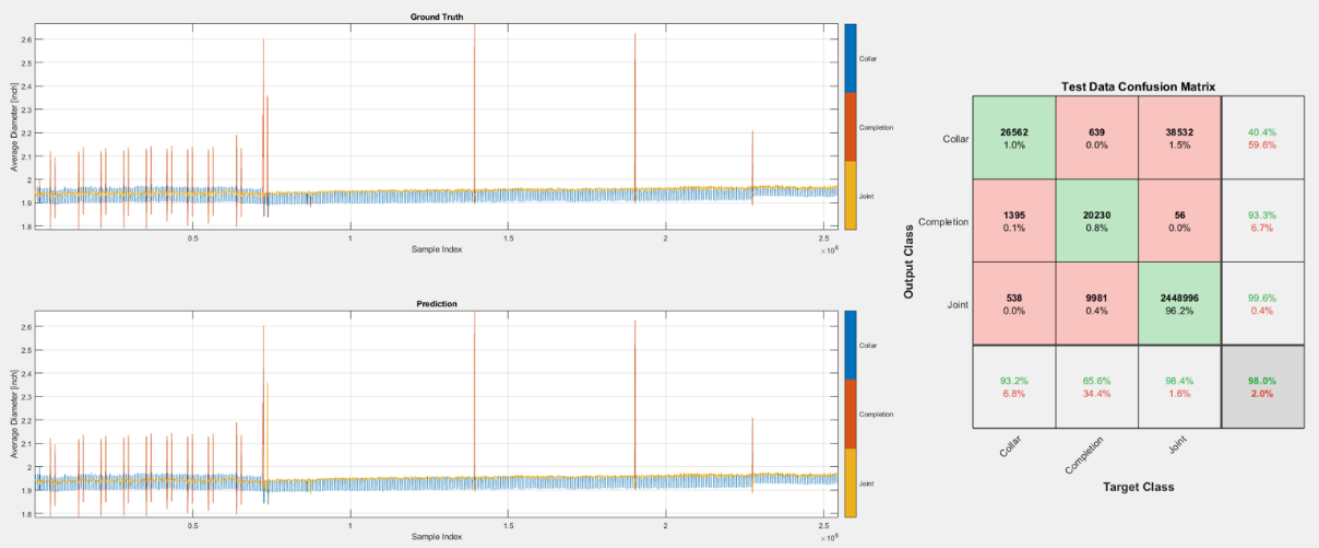
In virgin reservoir environments, formation pressure fluid gradients and contacts can support petrophysical interpretations. However, in depleted reservoirs with permeability heterogeneity and zone baffling, interpreting fluid gradients with high confidence becomes risky or even impossible.

To address these challenges, this study proposes a novel method that monitors pretest flowline fluid compressibility during decompression and recompression phases before and after the pretest. This method highlights gas ingress into the flowline, indicating mobile gas at specific depths. When combined with high-resolution density measurements, which minimize shoulder bed effects, the presence of gas becomes more evident. Advanced techniques such as ELAN and spectroscopy for lithology evaluation, along with alpha processed density, neutron, and resistivity, further enhance the petrophysical analysis.

Automating MFC processes through modularised ML models

John Guntoro – ANSA Data analytics

The Global Oil & Gas industry has, over the years, accumulated vast amounts of legacy multi-finger caliper (MFC) data resulting of decades of well integrity logging surveys. Immense value is currently dormant within these datasets, which could enable life-of field modelling, better predicting well integrity issues, allowing for proactive intervention, extended well lifecycle and ultimately delivering improved environmental safety. Unlocking this value requires the comparison of legacy data. However, the diversity in methodologies used has resulted in a fragmented landscape of datasets which are difficult to compare, analyze, and leverage consistently across different assets. The absence of a unified framework for processing MFC data and the prohibitive time and cost of re-processing historical data has hindered the ability to extract meaningful insights and patterns from historical logs, limiting the industry's capacity to make informed decisions about well integrity and performance over time. With the advent of modern machine learning, we have created a more standardised approach through automation of MFC processing which delivers the ability to reassess historical data accurately, timely and in a cost-effective way. In this study, we present two modules which make part of this new framework. The first is the use of a denoising autoencoder for automatic outlier detection for centralisation. We showcase that the workflow could achieve 95% accuracy in synthetic data. The second module comprises the use of 1D convolutional neural network model for item detection where collars, joints and completion items can be automatically identified. Our proposed workflow demonstrates outstanding performance with F1 scores of 0.96, 0.925 and 0.64 on joints, collars and completion items respectively, on a test set. In conclusion, current and historical MFC datasets can now be processed using standardised methods supported by ML and AI, benefiting from great efficiency increases and lower cost which allows for the unlocking of previously unattainable value.



John Guntoro is a Machine Learning Engineer within ANSA Data Analytics. He started working as a geophysicist in Indonesia upon graduating from University of Southampton in 2014. Starting 2021, he joined the University of Aberdeen as a research assistant before joining ANSA in 2023. He is now focused on delivering automated solutions for Multi Finger Caliper processing at ANSA, using various optimisation and Machine Learning paradigms.

Autosteering Multiple Horizontal Wells Simultaneously with Machine Learning using Legacy Data from Unconventional Reservoirs. Example from the Eagle Ford Basin

Romulo Cuevas - ROGII

This paper presents a novel approach to optimizing horizontal well drilling by leveraging legacy data through an advanced autosteering technique powered by Machine Learning (ML).

Often legacy well data is discarded by subsurface teams who typically favour more recent data. However, it is possible to re-utilize and unlock valuable information from these wells. This work investigates how historical well data can be re-integrated into geosteering projects for increased precision in the drilling of future horizontal wells, and how this can be done with speed and efficiency with Machine Learning.

Through a simple process, the autosteering model reuses historical well data to reevaluate the reservoir structure with a percentage of accuracy to update both geomodels and 3D surfaces. In this way, it is possible to use legacy data for increased understanding of the reservoir structure. By automating the geosteering interpretation of well logs, this method can further be used to enhance the precision of well placement and accelerate decision-making processes.

Using both automated and semi-automated Spectrum Calculation, a neural network architecture interprets the structural tendency of the reservoir. A probabilistic "heat map" is then generated to update the structural tendency and to guide and facilitate steering decisions. A case study from the Eagle Ford Basin demonstrates how this ML-driven approach can be used to streamline operations and maximize drilling efficiency in unconventional reservoirs. The results show that this technique significantly reduces interpretation time while maintaining accuracy during integration of historical well data, making it a valuable tool for future drilling operations in the oil and gas industry.

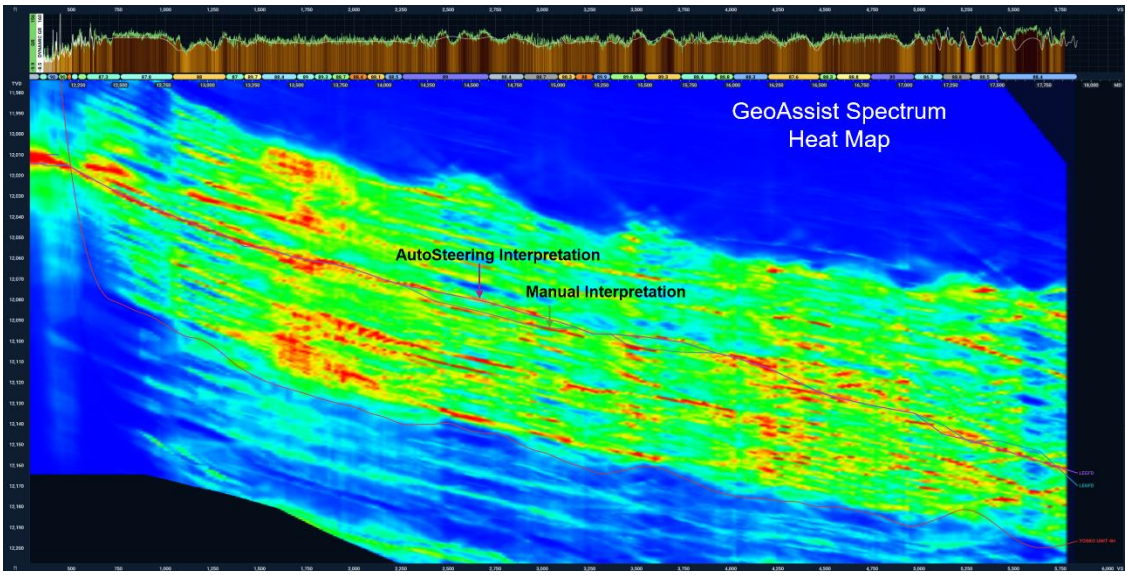


Figure. Spectrum Heat Map comparing structural tendency interpretation using Manual, Auto and Semi-automated Geosteering approach. Eagle Ford Reservoir. YOSKO UNIT 4H

Romulo Cuevas is a Geological Engineer graduated from the University of Los Andes. Currently working as a Senior Technical Analyst at ROGII, with over 10 years of experience in global oil and gas operations. He is skilled in planning and executing Geosteering projects in various environments and reservoirs. At present, Romulo is based in Europe.

A Cloud-based Machine Learning Approach for Well Interpretation

Emily Collett, Tim Ferriday - Halliburton

The interpretation of well data in the oil and gas industry has historically been carried out manually by trained human interpreters. Since the oil price downturns of 2015–16 and 2020, however, many geoscientists have left the industry, meaning fewer geoscientists to interpret the data and significant knowledge has been lost from the industry.

A solution to part of this challenge, is the use of supervised machine learning (SML) on the cloud. By combining SML with the scalability of cloud computing, large datasets can be interpreted rapidly using models trained by humans. SML also offers other advantages such as consistent interpretation across datasets, through removal of bias by different interpreters.

A SML approach was applied to a well dataset from the Alaska North Slope (Figure 1). First, an expert petrophysicist made detailed lithology interpretations from wireline data and created data labels to be used as inputs for model training. Then using the trained model, the SML algorithm generated a consistent lithology interpretation with uncertainty range, across 113 blind wells in five minutes. With careful selection of training wells, even though the Alaska North Slope dataset comprised wells of differing vintages, with limited log suites of variable quality, the SML algorithm successfully generated lithology classifiers with more than 70% lithological match to the human petrophysical interpretation, as well as identifying subtle changes previously missed and sections of bad hole.

A change in approach to SML on the cloud, could allow human interpreters more time to focus on high uncertainty sections and ultimately derive increased value from legacy datasets.

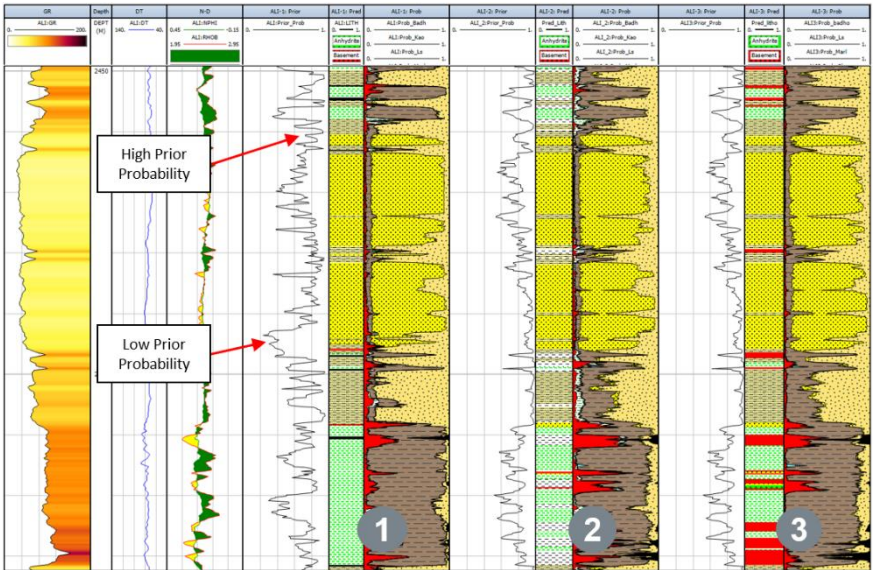


Figure 1: Results of a SML approach for rapid lithology interpretation modified from Popescu et al., 2021. The Prior Probability curve for each of the three model iterations is to the left of the predicted lithology strip.

Emily Collett is the Product Owner for Assisted Well Interpretation at Halliburton. She is responsible for the delivery of cloud geoscience applications offering contextual and integrated assisted interpretation of the subsurface. Emily joined Halliburton in 2014 and has held a variety of positions in geoscience, intellectual property management, project management and product management. Emily has a Masters in Geology from the University of Southampton, UK.