The Geology of Fractured Reservoirs

24-25 October 2018

The Geological Society

Corporate Supporters

Conference Sponsors

CONTENTS PAGE

Conference Programme	**Pages 3-6**
Oral Presentation Abstracts	**Pages 7-97**
Poster Presentation Abstracts	**Pages 98-112**
Fire and Safety Information	**Pages 113-114**

PROGRAMME

CONFERENCE PROGRAMME

Day One	
08.00	**Registration**
09.15	**Introduction - The Geology of Fractured Reservoirs – Some General Principles**
	Session One: Fundamentals of Fractured Reservoirs
09.30	**Keynote: Fracture corridors and structural diagenesis** **Stephen Laubach, *Bureau of Economic Geology, The University of Texas at Austin***
10.00	**Sampling biases in fracture logs from exploration wells: impact and mitigation** Liz Thompson, *Lundin Norway*
10.20	**Controls on fracture geometry: What can we learn from geomechanically-based DFN models?** Michael Welch, *Danish Hydrocarbon Research and Technology Centre*
10.40	**Reducing uncertainty in fracture modelling: assessing the sensitivity of inputs from outcrop analogues** Jonathan Long, *Geospatial Research Ltd*
11.00	**Break**
	Session Two: Fractured Clastic Reservoirs
11.20	**Natural Fracture Systems in Mudrocks (Upper Cretaceous-Eocene), Jordan** Israa Abu-Mahfouz, *University of Oxford*
11.40	**Using U-Pb calcite geochronology to constrain the timing of fracturing and fluid-flow in Jurassic mudrocks of the Cleveland Basin** Jack Lee, *Durham University*
12.00	**Impact of mechanical damage on fluid flow in mudstones: matrix versus fracture permeability of deformed Whitby Mudstone (UK)** Maartje Houben, *Utrecht University*
12.20	**Fracture Corridors' geometry: what can we learn from field analogues? Insights from Huamapampa sandstone in Bolivia (Icla Syncline)** Juliette Lamarche, *Aix Marseille University*
12.40	**Lunch**
	Session Three: Fractured Carbonate Reservoirs
13.30	**Keynote: Active Fracturing and Stresses in the Arabian Plate Basins: Patterns, Driving Factors, and Impact on Hydrocarbon Resources** **Mohammed S. Ameen, *Saudi Aramco***
14.00	**Natural Fracture Systems in Carbonate Reservoirs** Jo Garland, *Cambridge Carbonates Ltd*
14.20	**Contrasting deformation mechanisms within porous and tight carbonate rocks: examples from an outcrop analogue and insights on reservoir properties** Paolo Pace, *GE Plan*

14.40	**Critical fractures in carbonates: how early embrittlement and structural diagenesis affect reservoir properties?** Vincenzo La Bruna, *CEREGE-UMR*
15.00	**Quantifying fracture aspect ratios in reservoir-scale fractured carbonates** Richard Jones, *Geospatial Research Ltd*
15.20	**Break**
15.50	**Upon the Representative Element of Natural Fracture Networks in Carbonate Reservoirs: Insights from Deterministic Discrete Fracture Network Models** Thomas D. Seers, *Texas A&M University at Qatar*
16.10	**Dynamic Calibration of the Shaikan Jurassic Full-Field Fractured Caronate Reservoir Model Through Single-Well Drill Stem Test (DST) and Multi-Well Interference Discrete Fractured Network (DFN) Simulation** Neil Price, *Gulf Keystone Petroleum Ltd*
16.30	**Modeling dynamic behavior of fracture corridors from time lapse Electrical Resistivity Tomography (ERT) experiments. Application to the Calvisson Quarry (SE France)** Bertrand Gauthier, *Total EP*
16.50	**Insights from a multi-disciplinary fracture study of the Zechstein of NW Europe** Susie Daniels, *Geospatial Research Ltd*
17.10	Discussion
17.40	**Finish**
	Wine Reception

	Day Two
08.30	**Registration**
	Session Four: Fractured Basement Reservoirs
09.00	**Keynote: Characterising the fracture properties of Lewisian Gneiss basement reservoirs Rona Ridge, West of Shetland** **Robert Trice, *Huricane Energy***
09.30	**Fault Void Fills: Internal architectures of near-surface faults and implications for hydrocarbon reservoirs** Kit Hardman, *Durham University*
09.50	**Where is the fresh water coming from?** Carl Fredrik Gyllenhammar, *CaMa Geoscience*
10.10	**It’s a wee bit cracked: characterization of basement-hosted fracture systems, NW Scotland** Bob Holdsworth, *Durham University*
10.30	**Break**
10.50	**Characterization of a basement fracture system, Cheviot field, North Sea** Tim Needham, *Needham Geoscience Limited*
11.10	**Understanding the dynamic behaviour of the Lancaster Field, West of Shetland** Antony Harris, *Axis Well Technology*

11.30	**Basement Fracture Characterisation on the Liverpool Land Basement High, Central East Greenland** Graham Banks, *Geological Survey of Denmark and Greenland*
11.50	**A Review of the Yemen Fractured Basement Play** David M. Hall, *Sul Geology (Independent Consultant)*
12.10	Discussion
12.30	**Lunch**
	Session Five: Fractured Reservoir Data Integration
13.20	**Keynote: Characterising Fractured Reservoirs: insight from the movie "Life is Beautiful"** **Raffaele Di Cuia, *Delta Energy Limited***
13.50	**Fracture aperture in reservoir rocks: examples from the Shetland Chalk in the Gullfaks Field** Ole-Petter Wennberg, *Equinor Bergen, Norway*
14.10	**Fractured Reservoirs of Oman: Geological overview, challenges and opportunities for the development of hydrocarbon resources** Loic Bazalgette, *Petroleum Development Oman*
14.30	**North Kuwait Carbonate Fields: Calibrating fracture model permeability and porosity using core and pressure transient analysis data** Pascal Richard, *Shell Global Solutions BV*
14.50	**Break**
15.20	**Reservoir modelling challenges in naturally fractured tight carbonate reservoirs from the Potwar Basin, northern Pakistan** Sher Ali, *Ocean Pakistan Ltd*
15.40	**An Integrated approach to develop a prospective sub-thrust model in the Sub-Andes, Bolivia, and comparison to analogues in Iraq and Italy** Tina Lohr, *ERCE on behalf of Echo Energy & Pluspetrol*
16.00	**Characterization of fractured networks in geothermal reservoirs: from field outcrops to laboratory measurements** Catalina Sanchez-Roa, *University College London*
16.20	**An application to field development of permeability conduits characterization and distribution using geological scenario calibrated with pressure transient analysis data - A Brazilian pre-Salt lacustrine carbonate field example** Micheli Clavier, *Shell E&P*
16.40	**Old oil discoveries in tight fractured carbonates with limited fracture information: how to build a Discrete Fracture Network Model to help the appraisal strategy** Raffaele Di Cuia, *Delta Energy Limited*
17.00	Discussion
17.20	**End of Conference**

Poster Programme

The Detection, Classification and Impact of Stylolites and Associated Fractures in Carbonate Reservoirs Alexander Foote, *Badley Ashton*
High Resolution Mechanical Characterisation of Mudstones: A Comparative Atomic Force Microscopy Study Samuel P. Graham, *Newcastle University*
Subsurface Fracture Flow Evaluation - A Review Melissa Johansson, *Geode-Energy*
Storage and Fluid Flow Properties of Outcropping, Fractured Limestones of the Inner Apulian Platform, Southern Italy Vincenzo La Bruna, *CEREGE-UMR*
Practical experiments on modelling the connectivity of fracture networks Oscar Fernandez, *Independent Consultant*
3D model of a km-scale outcrop analogue of fractured hydrocarbon reservoirs: the Gozo Island Mattia Martinelli, *University of Milan*
Fracture attribute characterization in outcrop analogues by a combined field and multiscale photogrammetry approach: insights from platform carbonates folded in the Pag anticline, External Dinarides of Croatia Andrea Succo, *University of Parma*
The influence of structure, stratigraphy and observation-scale on fracture attributes: a case study from Swift Anticline, NW Montana Adam Cawood, *University of Aberdeen*
Fracture analysis of Qara Chauq outcrops as analogue to support Qara Chauq subsurface model, Zagros Fold and Thrust Belt, Kurdistan Region, Iraq Abdullah Awdal, *University of Kurdistan Hewlêr*
Analysis of Critically Stressed Fractures in the Shaikan Field, Kurdistan Region of Iraq Callum J. Gilchrist, *Imperial College London*

Oral Presentation Abstracts
(Presentation order)

Day one: Fundamentals of Fractured Reservoirs

KEYNOTE: Fracture corridors and structural diagenesis

Stephen E. Laubach
Bureau of Economic Geology, The University of Texas at Austin, University Station Box X, Austin, Texas, 78713, USA.

Mechanics is key to understanding how fractures form. But diagenetic processes, particularly cements precipitated during fracture pattern development, may play an essential but underappreciated role in governing fracture size patterns and spatial arrangement, including the tendency of fractures to cluster into corridors. Fractures form in rocks undergoing chemical alterations—diagenesis—in the presence of hot, reactive fluids. Reactions modify fracture and host rock mechanical properties and chemical processes are known to expedite propagation. Although some aspects of chemistry are currently used in mechanics-based models designed to predict patterns, the mechanical effects of cement deposits are not.

This presentation describes natural examples where differences in the potential for quartz to span opening fractures correlates with differences in patterns. Spanning potential (Lander & Laubach, 2015, *GSA Bulletin*) is a useful way to quantify degree of cement accumulation during fracture growth. Spanning depends on temperature history, rock type, and opening rate, among other factors. Spanning history can be unraveled with SEM-CL images, fluid inclusion assemblages, or with cement modeling. Standard methods quantify fracture size patterns, and the Normalized Correlation Count (NCC) method of Marrett et al. (2018, *J. Struct. Geol.*) documents degree of clustering (Fig. 1). Results from several case studies show correlations between amount of cement accumulated and fracture size distribution and spatial arrangement. Cement accumulation also systematical alters network connectivity. These pattern attributes of size, spatial arrangement, and connectivity are normally solely attributed to mechanical processes. Results point to opportunities for improving predictive models by more fully incorporating diagenetic effects.

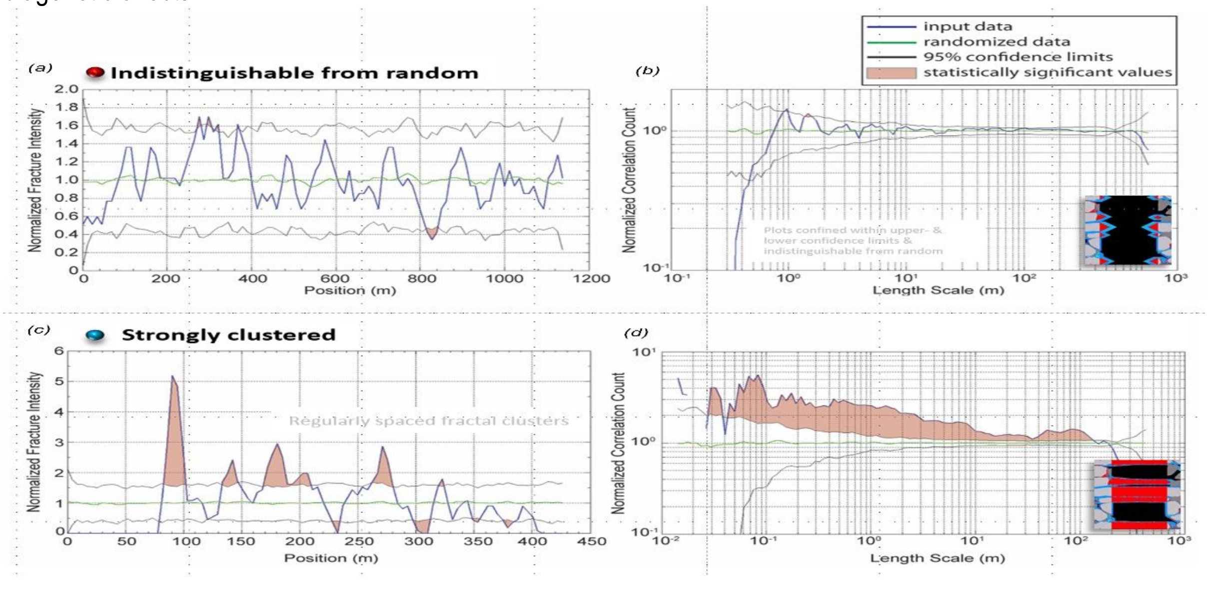


Figure 1. Opening-mode fractures documented in (a-b) outcrop and (c-d) horizontal core and image logs Cretaceous Frontier Formation sandstone. Fractures share ENE strike but have differing degrees of quartz cement spanning potential (after Li et al. 2018, J. Struct. Geol. using NCC of Marrett et al. 2018). Low spanning fractures have spacing indistinguishable from random, whereas high spanning has clustered fractures. Insets show model realizations from Lander & Laubach of non-spanning and spanning quartz.

NOTES:

Sampling biases in fracture logs from exploration wells: impact and mitigation

E. Thompson
Lundin Norway

Sampling biases affect fracture data collected along boreholes by wireline logs. Undersampling of the fracture population as a function of the relative orientation of the fracture and well bore changes the apparent fracture population distribution, as well as the apparent lineal and volumetric frequency as characterised by the P10 and P32 metrics. The fracture density distribution can be corrected, before being used for further modelling. Adjusting the densities does not create orientation information for the unsampled fractures that are being adjusted for. It cannot therefore allow examination of the impact of the increased fracture density on the orientation distribution.

In a field example from a North Sea basement reservoir, the density correction has been taken further, attempting to re-sample the population distribution to more closely resemble the sub-surface population. Additional virtual fractures are created using a Terzaghi adjustment weighting factor, with realistic orientations, and the distribution re-assessed to see the impact on orientation clustering and distribution statistics. The Terzaghi correction technique requires that a cut-off value be used to prevent unreasonably high correction values being applied. Using the weightings to create virtual fractures allows assessment of the impact on population clustering and cut-off values to be fine-tuned. Correlation between wells of different orientations enables a judgement on the presence or absence of different fracture populations and combining this with the cut-off values allows a more accurate assessment of the true fracture population.

These techniques were used (in combination with fracture roughness estimates) to generate a modelled fracture population and derive from it porosity and permeability properties. The current fracture network model gives porosity values that match the values observed in the petrophysical assessments.

NOTES:

Controls on fracture geometry: What can we learn from geomechanically-based DFN models?

Michael Welch & Mikael Luthje
Danish Hydrocarbon Research and Technology Centre

Introduction

At present fractured reservoirs are typically modelled either by modifying the bulk rock properties to take account of the fracture porosity and permeability, or using stochastically generated Discrete Fracture Network models (DFNs). Both methods tend to give a poor history match because the distribution, orientation, length and connectivity of fractures in the subsurface is not well constrained (Matthai and Nick 2009).

In this paper, we propose a new method of characterising fractured reservoirs and building DFNs by simulating the process of fracture nucleation and propagation based on geomechanical principles. We will show that this is able to replicate and explain many of the features we see in fractured outcrops, giving increased confidence that we can apply it to the subsurface.

Method

Our model is based on subcritical fracture propagation theory, as described by Atkinson (1984), based ultimately on the energy balance model of Griffith (1921). In this theory, the fracture propagation rate is controlled by the stress intensity at the fracture tip, which is itself a function of fracture size, the mechanical properties and stress state of the layer, and the subcritical propagation index b. Two styles of fracture propagation are recognised:

- Critical propagation, characterised by a high subcritical propagation index, is rapid but only occurs when the stress reaches a critical threshold value.
- Subcritical propagation, characterised by a low subcritical propagation index, is slower but can occur even at low stress.

The distinctive feature of our model is that we can apply these calculations to the cumulative distribution functions (e.g. P30 or P32) describing the fracture population as a whole, as well as to individual fractures.

In this study, we model the growth of fractures in a homogeneous brittle layer surrounded by ductile layers. We assume that this layer contains an initial population of small, circular microfractures (Figure 1 left). As a horizontal strain is applied to the layer, the stress generated at the fracture tips causes the fractures to grow. Initially they grow at a uniform rate in all directions, remaining circular, but eventually they intersect the top and bottom of the layer, which they cannot cross. They then become laterally-propagating layer-bound macrofractures, which can be approximated as rectangles (Figure 1 middle).

A key control on the geometry of the evolving fracture system is the interaction between these laterally-propagating macrofractures (Figure 1 right). There are two types of fracture interaction we must consider:

- Intersection with perpendicular or oblique fractures, leading to termination of the intersecting fracture.
- ”Stress shadow” interaction where one fracture falls into the stress shadow of another, parallel fracture. In this case both fractures stop propagating, but may link up via a relay segment to form a single continuous fracture.

The probability of fracture interaction at any time will be a function of the fracture population at that time. If we can calculate this, we can derive an analytical expression for the evolution of both active (propagating) and static (non-propagating) fracture populations through time, for all fracture sets.

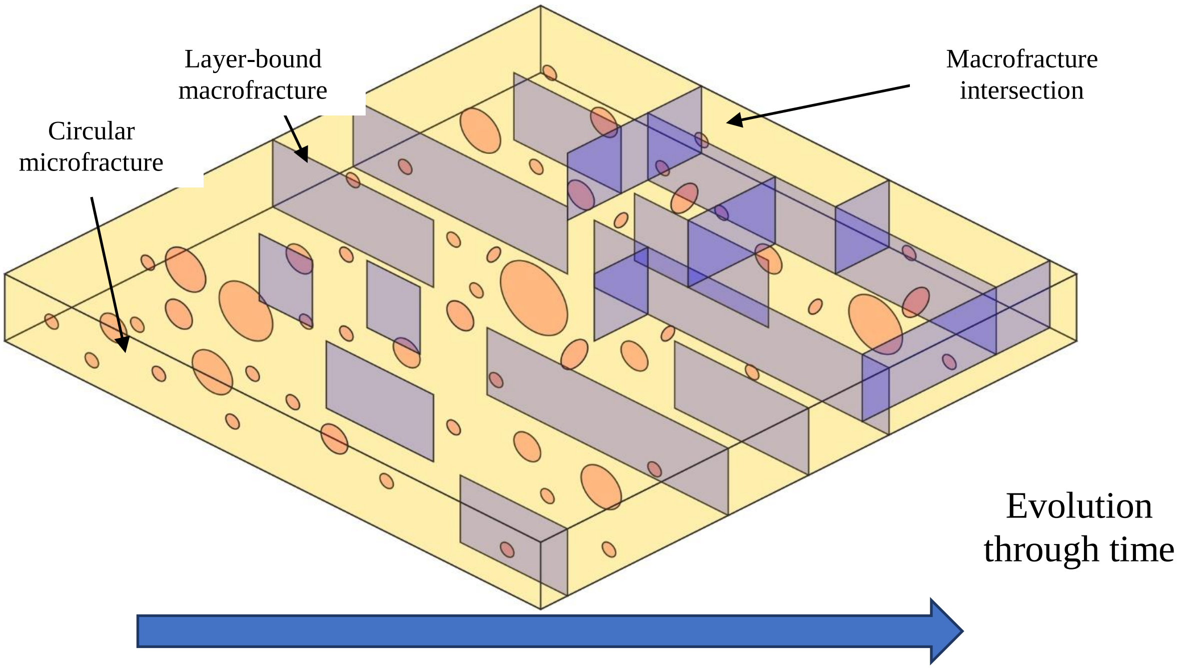


Figure 1: schematic evolution of a layer-bound fracture population through time, from left to right.

Application of the model

We have applied this algorithm to 3D models of various outcrops, covering a range of different lithologies, to test whether it can replicate the fracture geometries observed in those outcrops. In this presentation we will look at 3 such outcrops: Robin Hood's Bay, Nash Point and Flamborough Head.

Robin Hood's Bay in NE England is an outcrop of thin Lower Jurassic limestone layers, typically 0.5-1m thick, interbedded with ductile shales. The limestone layers are heavily fractured as a result of stress induced by displacement on the Peak Fault, a km-scale normal fault c.1km to the west. The fracture pattern varies along the shoreline, from anisotropic fractures (a set of long primary fractures connected by short secondary fractures) to a more isotropic pattern (where fractures from each set terminate against the other), as shown in Figure 2. The fractures were mapped in detail by Rawnsley et al. (1992), who point out that the key control on fracture geometry is the laterally variable stress field generated around a splay in the peak fault.

We generated a simple 3D model of Robin Hood's Bay, and used Petrel's Fracture Modelling module to reproduce the stress field around the Peak Fault. We then used this as input into our algorithm to generate local fracture patterns in the limestone layers. As Figure 2 shows, our model was able to replicate the observed lateral variability from anisotropic to isotropic fracture patterns along the coast. Sensitivity analyses have shown that with moderate to rapid facture propagation rates (subcritical index b>=10) only a small degree of stress anisotropy is required to generate anisotropic fracture patterns.

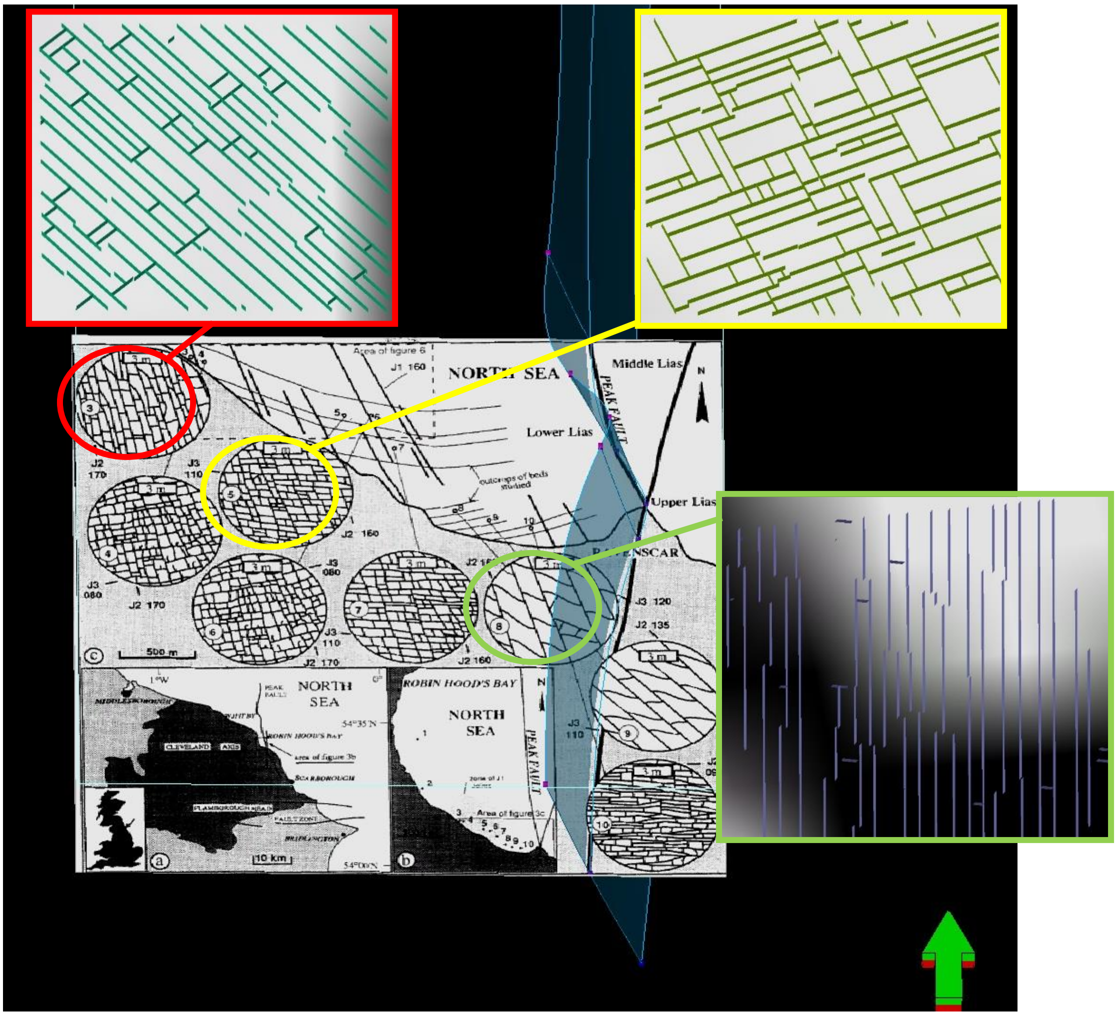


Figure 2: Simple 3D model of the Peak Fault and Robin Hood's Bay, with the fracture map of Rawnsley et al. (1992) superimposed. Note the good match between the lateral variation in fracture geometry mapped by Rawnsley et al. and the fracture geometries at the same locations generated by our model.

Nash Point on the Northern side of Bristol Channel in Southern Wales is an outcrop of fractured inter-bedded limestones and shales of Lias Group, Lower Jurassic. The individual layers are mostly less than 1m thick but can be laterally continuous for more than a kilometer (Bourne and Willemse, 2001). They are exposed along horizontal wave-cut platforms of up to 150m. The stress orientation varies locally around a set of strike-slip faults, and this is reflected in the fracture orientation. We show that our model can reproduce the complex fracture geometries observed in outcrop.

Flamborough Head is an outcrop of Upper Cretaceous chalk located c.30km south of Robin Hood's Bay. Fractures are developed in response to a regional strain, but locally some veins are developed around a larger fault. Different styles of fracturing are developed in different stratigraphic layers: 10cm-scale vertical dilatant fractures are developed in the uppermost Burnham Chalk Formation, while m-scale inclined conjugate shear fractures are developed in the lower Welton Chalk Formation. We use our model to investigate the conditions under which the different styles of fractures can develop.

NOTES:

Reducing uncertainty in fracture modelling: assessing the sensitivity of inputs from outcrop analogues

Jonathan J. Long, Richard R. Jones, & Susie E. Daniels.
Geospatial Research Ltd.

The conceptual understanding gained from outcrop analogues provides crucial insights into natural fracture networks, which are difficult to appreciate from borehole data alone, especially in areas of exploration where wells are sparse and knowledge of the reservoir is minimal. However, the interpretation of geological data almost invariably involves human input, which introduces interpreter bias into the workflow (Bond et al. 2007a,b). Therefore to reduce the uncertainty that is inherent in data derived from analogue outcrop studies, the degree to which different interpreters may affect the resultant outputs must be understood, and non-geological variations need to constrained and mitigated. We apply this approach to quantify the variability in fracture network interpretations derived from satellite imagery, using a population of geologists of varying levels of expertise and experience.

In each example within this study we asked all participants to pick fractures from the same satellite image, and then compared their results. Two examples are shown in Figs. 1A and 1B. We selected examples of different fractured carbonate units with varying degrees of image quality. The interpreters picked the areas of interest under the same conditions. In our analysis of the results, we focus on the variations in topology, orientation, intensity and length within the resultant fracture network that each participant picked. We illustrate the implications of the variability with respect to DFN modelling, and suggest strategies to standardise fracture interpretations to reduce picker-bias, by post-processing the picks using a topological correction and linkage algorithm. We also asked participants to complete a short questionnaire to assess their level of background knowledge of structural geology and experience of fracture picking; however at this stage in our analysis we are only able to make preliminary inferences on causes of the variations, due to small sample sizes.

As expected, we see significant variability in the interpretative picks from different geologists (e.g. Figs. 1C and 1D). The degree to which this variability affects fracture modelling is addressed with respect to orientation, connectivity, and length-intensity scaling. The biggest variation arose as a consequence of how different people digitised closely spaced fractures (fracture arrays), and which fractures people chose to pick (affecting intensity, for example). Two endmember styles were present in the interpretative picking of fracture arrays; either to pick many segmented co-aligned fractures, or to pick a single fracture spanning long distances. This difference in picking style has a profound effect on inferred size-intensity scaling relations, and there is an approximate three-fold range in picked fracture intensity within a single area of interest.

By applying a topological and linkage correction to the picked data the variance in the measured parameters decreased. However, significant variations in bulk fracture properties still existed in the post-processed interpretations. Variability might be further mitigated by improved training of inexperienced pickers by fracture experts, or by expert-led implementation of machine learning algorithms. Understanding the use-case for a specific fracture study is important: the human aspect of uncertainty in fracture modelling can and should be minimised at all stages in the interpretation process.

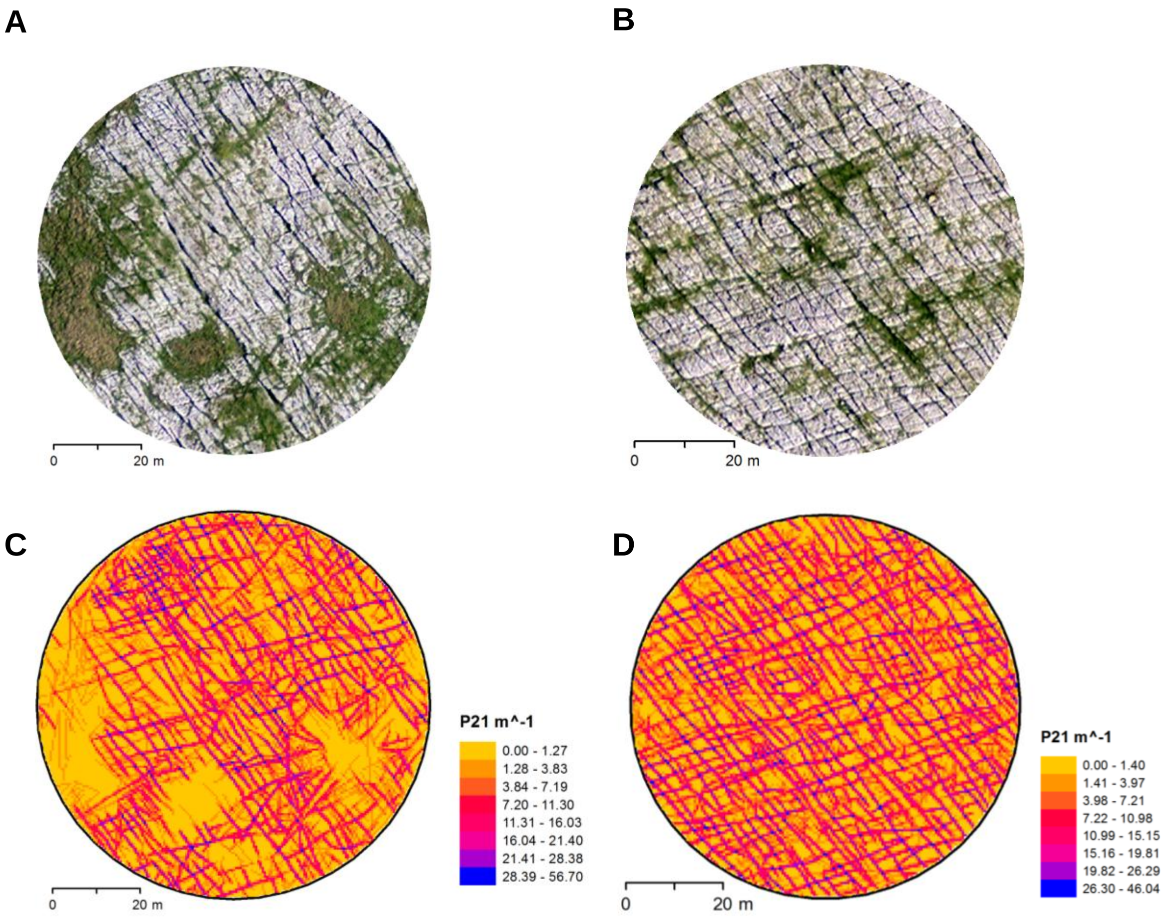


Fig. 1.(A, B) Two examples of areas of interest (with varying amounts of vegetation cover that degrade the quality of outcrop). (C, D) Variation in intensity of all the picked fractures for the two areas of interest in A & B respectively. Darker colours represent areas picked by more people.

NOTES:

Session Two: Fractured Clastic Reservoirs

Natural Fracture Systems in Mudrocks (Upper Cretaceous-Eocene), Jordan

Israa S. Abu-Mahfouz[1], John N. Hooker[2], Michael R. Gross[3], Joe Cartwright[1]
[1] University of Oxford, Department of Erath Sciences, South Parks Road, OX1 3AN Oxford, United Kingdom
[2] Pennsylvania State University, Department of Geosciences, 503 Deike Bldg., University Park, 11Pennsylvania, 16802
[3] Nautilus World, Ltd.

Natural fractures have a significant impact on fluid storage and flow. However, the interaction of stratigraphic framework, fluid migration, diagenesis, tectonics, and fracturing remains poorly understood. The Maastrichtian through Early Eocene of Jordan which comprises the Jordan Oil Shale and under- and overlying chert-rich units represents a potential hydrocarbon reservoir containing abundant natural fracture systems, offering opportunities to study the interaction between tectonic and diagenetic fracture formation mechanisms. The shallow burial depth of the section suggests that the fractures formed under relatively low burial stress conditions, giving an opportunity to study fracture formation during shallow burial conditions. The aim of this study is to characterize the fracture systems in the Maastrichtian through Eocene section of Jordan, including their stratigraphic distribution, formation mechanisms, and timing; understand them in a structural and basin evolutional context, and evaluate their effects on hydrocarbon migration and potential for economic production. Fracture type, morphology and mineralogy were described, and the frequency and length of different fractures were measured from outcrop (open-pit quarries) and fifteen cored wells located across Jordan. The fracture dataset included 11334 fractures from core within a total core thickness of 3212m and 3280 fractures from the outcrop. A variety of analytical techniques were performed including geostatistical analyses of fracture intensity and distributions, aperture scaling, isotopic analysis of host rocks and fracture cement, and petrographic investigation.

Distribution analyses of fractures divided the section into three units; upper and lower highly fractured units and a middle low fractured unit consistent with well tests indicative of very low matrix-dominated permeability. Different fracture cements including calcite, silica or chalcedony are commonly linked to host-rock lithology, suggesting a chemically closed system. Bitumen is present within natural fractures and adjacent vugs, either as macroscopically visible deposits or as inclusions in the fracture cement. Bitumen inclusions suggest that hydrocarbons were generally present during and after the opening of most fractures. Joints (unmineralized fractures) in the Jordan Oil Shale are often confined to specific beds minimizing the potential risk due to the high fracture intensities within the upper and lower units which can be posed where fracture networks are connected. Fractures are commonly associated with nodules in the Maastrichtian section, implying that fracturing is sensitive to diagenesis. Mechanical stratigraphic controls on fracture intensity, relationship to compaction and early cementation, as well as the presence of bitumen within fractures, suggest that fracturing was affected by different processes and have different timings. The mechanisms that controlled fracture formation throughout the section can be summarized as fluid pressuring (creating calcite/gypsum bed-parallel veins), early diagenesis (e.g. folded calcite veins and planar silica veins) and late tectonic processes (planar calcite veins and joints associated with fault damage zones). Petrographic and geochemical analysis show that fracture timing can be divided into two groups. These include early calcite veins folded by sediment compaction, and late fractures formed during uplift or associated to fault reactivations. Faults seem to have slipped through the burial and uplift history of the section, based on the presence of plastic sediment deformation and fracturing related to these movements as well as brecciation and calcite-sealing that cuts earlier cements.

NOTES:

Using U-Pb calcite geochronology to constrain the timing of fracturing and fluid-flow in Jurassic mudrocks of the Cleveland Basin

Jack Lee*[1], Jonathan Imber[1], Nick Roberts[2], Richard Haslam[2], Robert Holdsworth[1]
[1]*Department of Earth Sciences, Durham University*
[2]*British Geological Survey, Keyworth, Nottingham*

Organic-rich mudrocks are of great significance to the petroleum industry, potentially acting as top seals, source rocks and/or unconventional reservoirs. Natural fractures within mudrocks can strongly influence top seal integrity, primary migration and the performance of unconventional (e.g. shale gas) reservoirs. This PhD project combines structural geology with isotope geochemistry and cutting-edge U-Pb calcite geochronology to constrain the relative and absolute ages of faults and fractures within an exhumed, early mature, Early Jurassic mudrock succession in the Cleveland Basin, NE England. The abundance of well-exposed, natural fractures with different orientations and failure modes provides an opportunity to investigate the properties of these fractures and how they relate to palaeo-fluid flow. This project will develop an integrated understanding of fracture initiation and potential reactivation and fluid migration history during burial and exhumation of the Cleveland Basin.

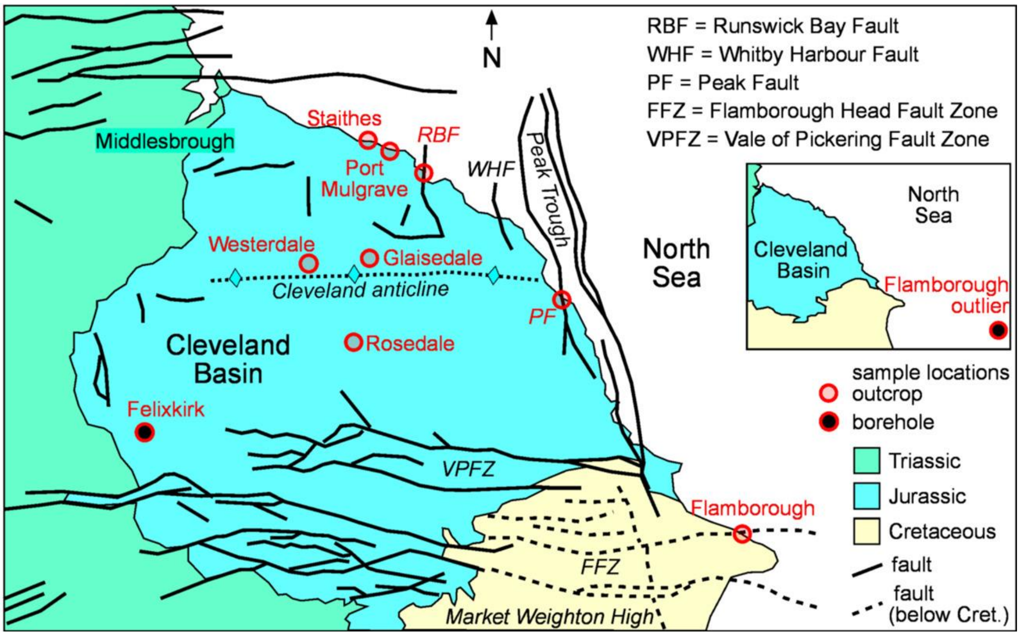


Fig.1. Structural map of the Cleveland Basin with previous and planned sampling locations for U-Pb calcite dating of fractures and faults.

The Cleveland Basin is an extensional basin that formed in the Mesozoic and overlies earlier, Carboniferous and Zechstein (Permian) depocentres. The Cleveland Basin is bounded to the northeast by the Mid-North Sea High, the Market Weighton High to the south and by the Pennine High to the west. The basin is linked to the Sole Pit Trough – the onshore Cleveland Basin therefore represents a westward continuation of the Southern North Sea.
Subsidence in the Cleveland Basin was initiated at the end of the Triassic and continued with only minor interruption through to the Cretaceous. Inversion of the basin is interpreted as latest Cretaceous to Neogene, and resulting from far-field stress from Alpine Orogeny. Both the northern and southern margins of the basin are highly faulted with the northern margin dominated by N-S/NNW-SSE striking, predominantly normal faults in addition to E-W striking faults. The southern margin is characterised by the E-W striking Flamborough and Vale of Pickering Fault Zones (Fig.1).

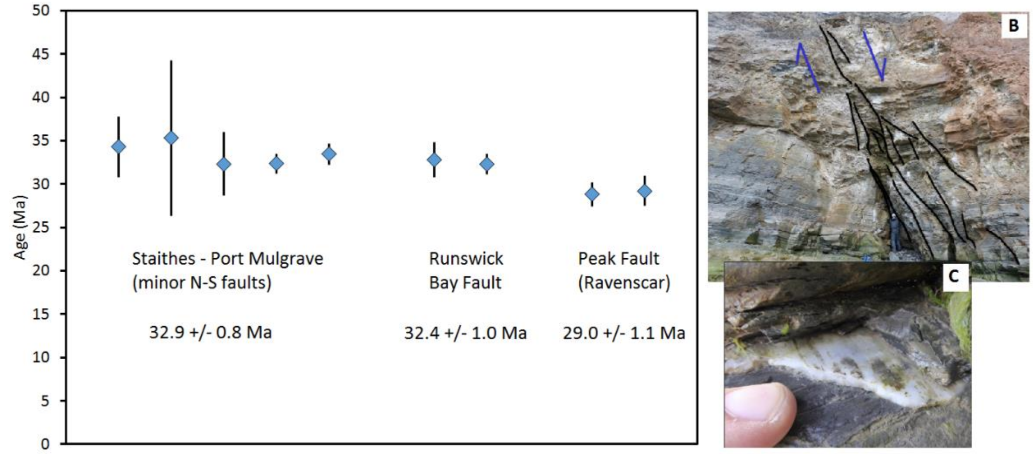


Fig. 2. A) Results of U-Pb calcite dating from N-S faults between Staithes and Ravenscar. B) Typical low displacement (<2 m) N-S normal fault at Staithes. C) Syn-kinematic calcite vein fill with down-dip lineation on surface.

Multiple calcite fault fills (some of which contain bitumen) from a selection of minor (<2 m offset) to major (Peak Fault) N-S faults have been sampled and analysed for an initial pilot study (Fig. 2). Most faults sampled have a normal, dip-slip sense of movement with no observed indications of reverse reactivation. In addition, many of the calcite vein fills provide evidence for syn-kinematic calcite mineralisation: 1) dip-slip calcite slickenfibres; 2) crack-seal-slip textures; and 3) mineralised pull-apart structures. These mean the calcite U-Pb dates can be used as an indicator of the timing of fault slip. The methodological approach involves the combination of sample imagery, elemental and isotopic data to link the obtained dates to geological processes, i.e. a petrochronological approach.

Our initial study yielded nine successful dates from thirteen samples, all ranging from 36 to 27 Ma (latest Eocene to early Oligocene), with pooled mean ages of 32 Ma (Staithes to Runswick Bay) and 29 Ma (Peak Fault, Ravenscar). These ages are significantly younger than the previously interpreted Jurassic to latest Cretaceous normal fault movements. Our initial work documents an unrecognised period of Cenozoic extension in the Cleveland Basin, which we link to salt tectonics, evidence for which is preserved offshore in blocks 42/29 and 47/4b. This event could have a previously unknown control on the migration of hydrocarbons within the Cleveland Basin and possibly the Southern North Sea. More fundamentally, the presence of bitumen in calcite-filled faults with Cenozoic ages raises important questions concerning the mechanism and timing of maturation and uplift within the Cleveland Basin. In addition to these major findings, the project will focus on delivering impacts to stakeholders in the Petroleum Industry, through detailed analyses of the timing and process of fracture initiation and propagation in mud-rich lithologies, and through demonstration of the applicability of U-Pb calcite geochronology to understanding local and basin-scale tectonics.

NOTES:

Impact of mechanical damage on fluid flow in mudstones: matrix versus fracture permeability of deformed Whitby Mudstone (UK)

Maartje Houben[1], Jasmijn van Eeden[1], Suzanne Hangx[1], Lisanne Douma[2], Auke Barnhoorn[2]
1 Faculty of Geosciences, Utrecht University, Budapestlaan 4, 3584CD Utrecht, the Netherlands
2 Faculty of Civil Engineering and Geosciences, Stevinweg 1, 2628CN Delft, the Netherlands

Considering fluid flow in mudstones, such as gas flowing from the matrix to a production well, we should account for the dual permeability of the medium considering a higher permeable fracture network together with a tight matrix. In the context of fluid production, it is key to be able to quantify the impact of (induced) mechanical damage on permeability, aimed at improving flow, as a function of the state of stress and bedding orientation.

We conducted a series of experiments to investigate permeability change in response to deformation and damage. We used cylindrical 1 inch diameter samples of Whitby Mudstone (UK) as an analogue for typical mudstones and shales used for shale gas production. Bulk sample permeability of the Whitby Mudstone was measured perpendicular, parallel, and at an angle to the bedding before and after deformation of the material, induced at a confining pressure of 30MPa using a direct shear setup. For intact material, matrix permeability perpendicular to the bedding was consistently one to two orders of magnitude lower than the permeability parallel to the bedding, on the order of 10^{-19}-10^{-22} m^2 and 10^{-18}-10^{-20} m^2 at confining pressures of 3-30 MPa, respectively. The matrix permeability was 10^{-19} m^2 at 3 MPa confining pressure when measured oblique to the bedding, but dropped below the detection limit (i.e., < 10^{-23} m^2) at higher confinement. All samples showed a 2-5 orders of magnitude increase in permeability at low confining pressure (3 MPa) after deformation of the shales. At high confining pressure (30 MPa), permeability increased 4-5 orders of magnitude for the sample oblique to bedding, and half an order of magnitude for the sample perpendicular to the bedding, permeability measured parallel to the bedding was similar before and after deformation.

X-ray micro-tomography analysis of the samples after deformation showed that fractures preferentially developed parallel to bedding, with a well-developed fracture network connecting top and bottom of that particular sample. Such a fracture network was also visible, but less extensive, in the oblique-to-bedding sample. The sample taken bedding-perpendicular lacked a distinctly visible connecting fracture network, although permeability was enhanced after deformation. This suggests that on a (much) smaller scale, fractures must have developed in the form of a damage zone which still resulted in increased permeability of the matrix, as opposed to fracture flow dominating permeability. Additional Scanning Electron Microscopy was performed on the deformed samples to investigate the extent of the damage zone.

NOTES:

Fracture Corridors geometry: what can we learn from field analogues? Insights from Huamapampa sandstone in Bolivia (Icla Syncline)

Lamarche J.[1]; Gauthier B.D.M.[2]; Viseur S. [1]
[1] Aix Marseille Univ, CNRS,
[2]Total EP

Introduction and aim

Fracture corridors (FCs) are high density persistent fracture zones within diffuse fracture bearing rock occurring from cm to multi-km scales. In sub-surface, FCs are a major issue. Indeed, when crossed by wells, they can be high permeability, super-K, pathways for hydrocarbon production and/or for water breakthrough. FCs drains are barely visible on seismic and appear on borehole imaging log as networks of concentrated fractures which could also be interpreted either as bed-confined fracture swarm or as sub-seismic fault zones.

The underground hydraulic properties of FCs are well characterized but their structural architecture is poorly constrained because of their sub-seismic resolution. Particularly, their distribution laws and geomechanic conditions of growth remain poorly known. The mechanical theory of stress shadow and fracture height explaining the diffuse fracture distribution fails to explain the case of FCs, and the tectonic conditions for their setting up are still debated. Engelder (1987) interpret FCs as joints reactivated by shear, while Questiaux et al. (2010) suggest they form as fold accommodation structures. Other authors link them to fault zone tips (Singht et al., 2008) or early fault zones (Petit et al comm. pers). Lamarche et al (2017) suggest that they could be early features not necessarily related to a main tectonic event.

We aim at deciphering the 3D pattern and geodynamic context for FCs. To this end, we studied the Icla Syncline (Andean Foreland Belt, Bolivia) where FCs affect Devonian sandstones of the Huamapampa and Santa Rosa formations, which are the stratigraphic and structural analogue for many gas fields in the country. We sampled the heterogeneity of FCs from large to small scales (Figure). We applied a multiscale analysis workflow including field structural analysis, photogrammetry and satellite picture interpretations. Subsequently data have been integrated into a 3D structural model of the Icla Syncline within the Gocad software.

Setting up geodynamic context

The Icla syncline is an asymmetric kink-fold with a steep west flank up to sub-vertical and a gently 20° to 40° dipping east flank and a NNW-SSE oriented fold axis. We investigated both limbs of the fold where 725 fractures in FCs, 32 faults and 137 beddings planes have been measured. FCs are neither parallel nor perpendicular to the fold axis, nor cross-cutting through the fold. They are not localized along the hinge, but equally observed on both limbs, and not related to faults or fault tips. FCs are mostly organized in 1 set, and scarcely in 2 perpendicular to sub-conjugate sets. Like the diffuse fractures, they are perpendicular to bedding whatever the limb and the dip. They strike E-W in average after back-tilting. Hence, FCs are interpreted to develop before -or at- the early onset of the fold, under a stress induced by burial load combined with far field effect of the E-W Andean compression.

Fracture corridors multi-scale architecture

FCs have been observed at all scales in the Icla Syncline, from few cm to hundreds of meters (Figure). At all these scales, FCs are controlled by mechanical stratigraphy: they go through- multi beds but their width vary along height depending on bed stratonomy. Fracture arrangement evolves from dense & numerous clusters to single HPF fracture. FCs “stop and go” at lithological boundaries when crossing through massive sand sequences alternating with shaly sands. At all scales, FCs are anastomosed and separated by unfractured zones. ORAL REQUESTED

Examples of multi-scale fracture corridors cropping out in the Icla Syncline in the Huamapampa (100, 10, 0.1m) and Santa Rosa (1m) sandstones.

Conclusion

FCs in the Icla Syncline are fold-transverse, perpendicular to conjugate, Mode I, single to two sets of fractures formed at depth at the early onset of the folding. They form “stop and go” anastomosed sets sensitive to the mechanical stratigraphy of sandstones. Fracture corridors are observed at all scales with a vertical persistence but with a fracture density and width depending on the stratonomy. These qualitative observations suggest that transverse FCs are widely distributed on both fold flanks but with limited lateral and vertical connectivity. Indeed, both limbs are not connected because no, or very limited, fracture(s) occur(s) along the fold hinge. In addition, fracture corridors are vertically limited by the mechanical stratigraphy. Since they are early structures, similar FCs can be expected in the subsurface. In this case, only the larger corridors related to thick mechanical units may connect the water table with overlying reservoirs.

Geometry of FCs in sandstones was compared with that of burial-induced FCs in platform carbonates. We observed very similar anastomosed patterns and mechanical stratigraphy dependence at all scales. The lateral and vertical variability of internal fracture architecture is also remarkable. Hence, FCs are sensitive to stratigraphic arrangement but not to lithology at all scales. While the depth and stress conditions for burial-related corridors is constrained, the mechanics for their genesis, density, polymorphic and multi-scale characteristics remain to be theorized.
Acknowledgements

Authors wish to acknowledge TOTAL S.A. (France) for financial support and TOTAL/EP Bolivia who organized the field survey. The authors would like to thank ParadigmGeo for they support in providing Gocad/Skua software and the AGSA as well as the RING-Gocad consortium for providing research plugins

NOTES:

Session Three: Fractured Carbonate Reservoirs

KEYNOTE: Active Fracturing and Stresses in the Arabian Plate Basins: Patterns, Driving Factors, and Impact on Hydrocarbon Resources

Mohammed S. Ameen
Principal Professional, Unconventional Geomechanics, Northern Arabia Unconventional Gas Asset Department (NAUGAD), Saudi Aramco, Dhahran 31311, Saudi Arabia

Natural fractures in the sedimentary sequences in the platform basins of the Arabian Plate show a repetitive occurrence of two episodes; an older early diagenetic episode and a later tectonic episode. This is evident from studies conducted by the current author over the last few decades covering different basins in the Arabian plate from the significantly attenuated High Folds Zone of the Zagros-Taurus to the mildly deformed Arabian platform of Saudi Arabia (Ameen, 1991a, b, 1992, 1995, 2002, 2014, 2016, Ameen and Hailwood, 2008 and Ameen et al., 2010, and 2012).

The early episode of fracturing is a manifestation of mainly gravity tectonics and includes seismites, slump structures, and natural fractures related to burial history or fluid chemistry etc. These fractures have distinctive orientations in their affinity to local paleoslopes, and/or underlying basement-fault escarpments, which controlled the basin topography and the fold/fault structures. Characteristically such fractures are limited in their extent and are the least abundant and therefore have no major influence on hydrocarbon resources. In contrast, the later episode of fracturing is mainly tectonic and includes nearly vertical extension fractures, faults, and tectonic stylolites. Their patterns include more than one set of fractures, which are predominantly systematic relative to the current day plate tectonic stresses, and they are rarely influenced by local structures (folds and faults). In addition the density of these fractures increases towards the Arabian-Eurasian collision zone. Therefore they are considered as regional tectonic fractures primarily driven by the Arabian Plate tectonic stresses, which have been active since the Cretaceous. The latest dominant set of tectonic fractures imprints the older sets, this reflects the progressive counter clockwise rotation of the Arabian Plate and related remote stresses. The plate rotation resulted in shear rejuvenation of older fractures that are suitably oriented in compressional, extensional strike-slip, compressional strike-slip, and thrust modes. The degree of mineralization of these fractures varies across the sedimentary section of the Arabian Plate depending on the rock type, fluids chemistry, pressure, temperature and burial history. A considerable number of these fractures are open hairline or partly mineralized fractures facilitating fluid flow. The occurrence of these fractures resulted in part from the increase in pore pressure that coincided with the hydrocarbon generation in the source rocks and facilitated the expulsion from the source rocks. Subsequent hydrocarbon placement in reservoirs, cracking both within source rocks and reservoirs enhanced the continuous development of this episode of fracturing. These regional, plate tectonics-related fractures play an essential role in enhancing permeability in both conventional and unconventional oil and gas reservoirs with both desirable and undesirable consequences. In addition their strike is nearly parallel or at an acute angle to the current day maximum horizontal in-situ stresses and therefore a positive factor that enhances the stimulation efficiency of unconventional and tight gas reservoirs.

NOTES:

Natural Fracture Systems in Carbonate Reservoirs

Jo Garland, Andrew Horbury, Benoit Vincent, Pete Gutteridge, Julie Dewit and Sarah Thompson
Cambridge Carbonates Ltd, Solihull, UK.

Approximately 50% of all carbonate-reservoired oil and gas fields worldwide are naturally fractured. This number is high compared to their siliciclastic counterparts. It is therefore important to not only be able to predict fractures in carbonates, but also to understand their impact on production.

Whilst tectonic mechanisms are responsible for many of these fractured reservoirs, particularly in fold and thrust belts and foreland basins, one should not underestimate the impact of other processes that create fractures, and thus permeability, in carbonate rocks.

Karstification: karst processes result in stratiform, heterogeneous fracture systems which have typically been dissolution-enhanced. The resulting fracture network includes not only fracture propagation into roof and wall rocks, but also commonly results in thick breccia systems formed through cave collapse.

Evaporite collapse: evaporite collapse breccias are formed where anhydrite and/or gypsum are dissolved, and the overlying continuous strata of carbonate rocks collapse, generating dissolution-collapse breccia composed of carbonate clasts. Fracture systems associated with this mechanism are inherent in the overlying, foundered, carbonates as well as in the breccias themselves.

Fracture-related dolomitisation: fracture related dolomite bodies occur where hot, Mg-rich fluids move upwards through fractures, dolomitising the surrounding host carbonates (also known as hydrothermal dolomites). These “hot” dolomites can add additional matrix porosity, or reversely destroy porosity, to what would traditionally may be considered a tectonically-fractured reservoir, thus resulting in a Type 2 fractured reservoir. Fluid overpressure may also create local hydrobrecciation in the surrounding host.

It is therefore critical to establish the mechanism responsible for creating fractures, since this will have a significant impact on the reservoir geometries and how the fractures are modelled (Figure 2). Tectonic fractures are predictable in a statistical sense, and can be modelled through understanding the structural evolution. Karst fractures can be predicted in a stratigraphic framework, can occur over thick intervals, but their fracture pattern is semi-random within the collapsed breccia zones. Evaporite collapse breccias and fractured intervals are thinner and stratigraphically controlled. Hydrothermal dolomites can be modelled within a structural framework, and with understanding the existing stratigraphic architecture.

The only way to unravel the complexity of fracture systems in carbonates is by careful diagenetic studies from core, and integrating well logs, seismic and analogues.

FRACTURE STYLES IN CARBONATES

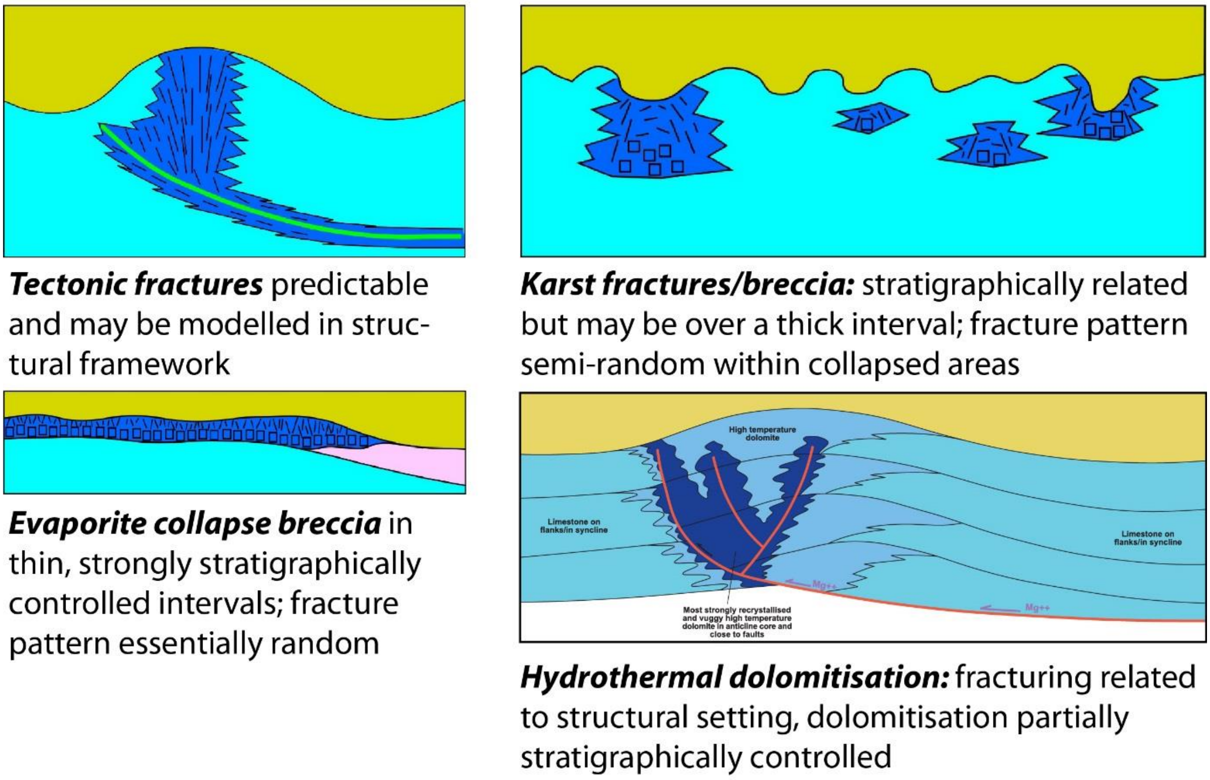


Figure 2 Summary of the four key fracture origins in carbonate reservoirs and impact on reservoir geometries

NOTES:

Contrasting deformation mechanisms within porous and tight carbonate rocks: examples from an outcrop analogue and insights on reservoir properties

Paolo Pace[1] & Raffaele Di Cuia[2]
[1]G.E. Plan Consulting, Petroleum Geosciences, Via Ariosto 58, 44121 – Ferrara, Italy
[2]Delta Energy Ltd., Central Court, 25 Southampton Buildings, London WC2A 1AL, UK

Within naturally fractured carbonate reservoirs, porosity, permeability pathways and/or impermeable fluid barriers are controlled by the interaction between fracture networks and host rock matrix. Indeed, contrasting modes of deformation mechanisms may considerably modify the porosity and permeability of either tight or porous carbonate rocks influencing fluid flow behaviour and reservoir characteristics. The study of fracture characteristics analysed from outcrop analogues allows understanding the nature and evolution of fracture networks with respect to mechanical stratigraphy providing also key insights for subsurface reservoirs.

Two main types of deformation mechanisms dominate in porous and tight rocks. Deformation bands (DBs) are low-displacement strain localization zones of deformation in porous rocks that are related to a variety of mechanisms. By contrast, discrete mechanical discontinuities as fractures and faults (F&Fs) accommodate deformation in tight rocks with a broader range of displacement and configuration.

The surface expression of these contrasting deformation mechanisms within porous and tight carbonates and their spatial relationships have been analysed on the Matera structural high in southern Italy, a horst feature within the foredeep-foreland of the Southern Apennines. There, extensionally faulted Cretaceous shallow-water tight limestones of the Apulian Platform are unconformably overlain by Tertiary porous calcarenites. DBs appear as light-coloured, mm- to cm-thick structures forming protruding ridges in the pale cream bioclastic calcarenites. They are mostly compactive shear bands also associated with some pressure-solution, oriented at high angles to bedding and widely distributed. Pure compaction bands also occur but are less diffuse. Compaction is evident as a reduction of pore space within the DB, relative to the porous host rock. Grain reorganization and pressure solution mainly accommodate strain localization. There are single bands, zone of bands, conjugate sets, swarms or more organized networks. Some of the high-angle DBs are nowadays open or partially open due to gravitational instability. Outcrop- and large-scale extensional faults, sub-vertical throughgoing fracture corridors, fracture sets and sub-horizontal stylolites characterise the tight Cretaceous carbonates. Fracture sets are with dm-to-m spacing and are organized in roughly perpendicular sets with mutual cross-cutting relations. All of these F&Fs are also locally associated to paleokarst dissolution features. DBs and F&Fs are characterised by similar trends.

The two contrasting deformation mechanisms here described from the Matera outcrop analogue have opposite perturbations on porosity and permeability: DBs dramatically decrease porosity in porous carbonates constituting barriers to fluid flow whereas F&Fs enhance permeability of tight rocks favouring fluid flow. The results of this field characterisation may help to understand the characteristics and behaviour of reservoirs made up by coupled porous-tight carbonates.

NOTES:

Critical fractures in carbonates: how early embrittlement and structural diagenesis affect reservoir properties?

La Bruna V.[1], Lamarche J.[1], Agosta F.[2], Giuffrida A.[2], Salardon R. [1], Rustichelli A.[3], Lavenu A. P. C.[4], Marié L.[1]
[1]*CEREGE-UMR, Aix-Marseille University, France*
[2]*Department of Science, University of Basilicata, Italy*
[3]*School of Science and Technology, University of Camerino, Italy*
[4] *ADNOC Offshore, Abu Dhabi, United Arab Emirates*

Bed-perpendicular diffuse fractures are common features in carbonates. Several studies documented how their distribution, dimension and overall geometry are affected by primary heterogeneities such as bed interfaces, erosional surfaces and pedogenic unconformities. Others studies showed that the early embrittlement may enhance vertically persistent, opening-mode fractures prior to formation of secondary bedding-parallel heterogeneities (e.g. stylolites, stratabounded dolomites) during diagenesis of platform carbonates.

These early-developed fractures could be independent of tectonics and form a background structural network from micro to regional scale. Abutting and crosscutting relationships between depositional and diagenetic heterogeneities, and secondary heterogeneities due to deformation, are to be investigated, as they allow reconstructing their relative timing of formation. The proposed analyses will be aimed at understanding the role played by the early diagenetic features linked to the sediment lithification processes, in controlling the formation, geometry and distribution of bed-perpendicular mode-I fractures confined (Strata Bound-SB or not Non Strata Bound-NSB, within the single rock layers. (Figures 1a).

This study focuses on the structural, petrographic, mineralogical, and petrophysical characterization, from outcrop- to micro-scale of Early Cretaceous, shallow-water, tight limestones pertaining to the Inner Apulian Platform, and exposed at the Monte Alpi in southern Italy (Figs. 1b, c,d,e) These carbonates consist of a wide spectrum of calcareous facies made up of mudstones, wackestones, packstones, grainstones and microbial bindstones. These rock types are related to a variety of depositional environments within a back-reef inner platform / platform margin to a rimmed platform (i.e., Apulian Carbonate Platform). Field stratigraphic analyses in concert with optical microscopy, SEM and cathodoluminescence analyses unrevealed the nature of the sedimentary/diagenetic interfaces (bedding, stylolites). Then, field and petrographic fracture analyses documented the abutting and crosscutting relationships between bed-perpendicular opening-mode fractures and both bed interfaces and bed-parallel stylolites present within individual beds. P-wave velocity and porosity measurements performed on collected samples revealed the petrophysical properties of the carbonate host-rock, and in particular unravelled the pore type/lithofacies/fracture pattern relationships. In fact, these analyses will highlight how if the fracture pattern are intrinsically related to the host rock pore type and also to the volume of porosity. Integration of all these results will show how carbonate textures, depositional settings and diagenetic histories are keystone controls exerted on early embrittlement processes, and hence on the geofluid storage and flow properties through the fractured limestone succession.

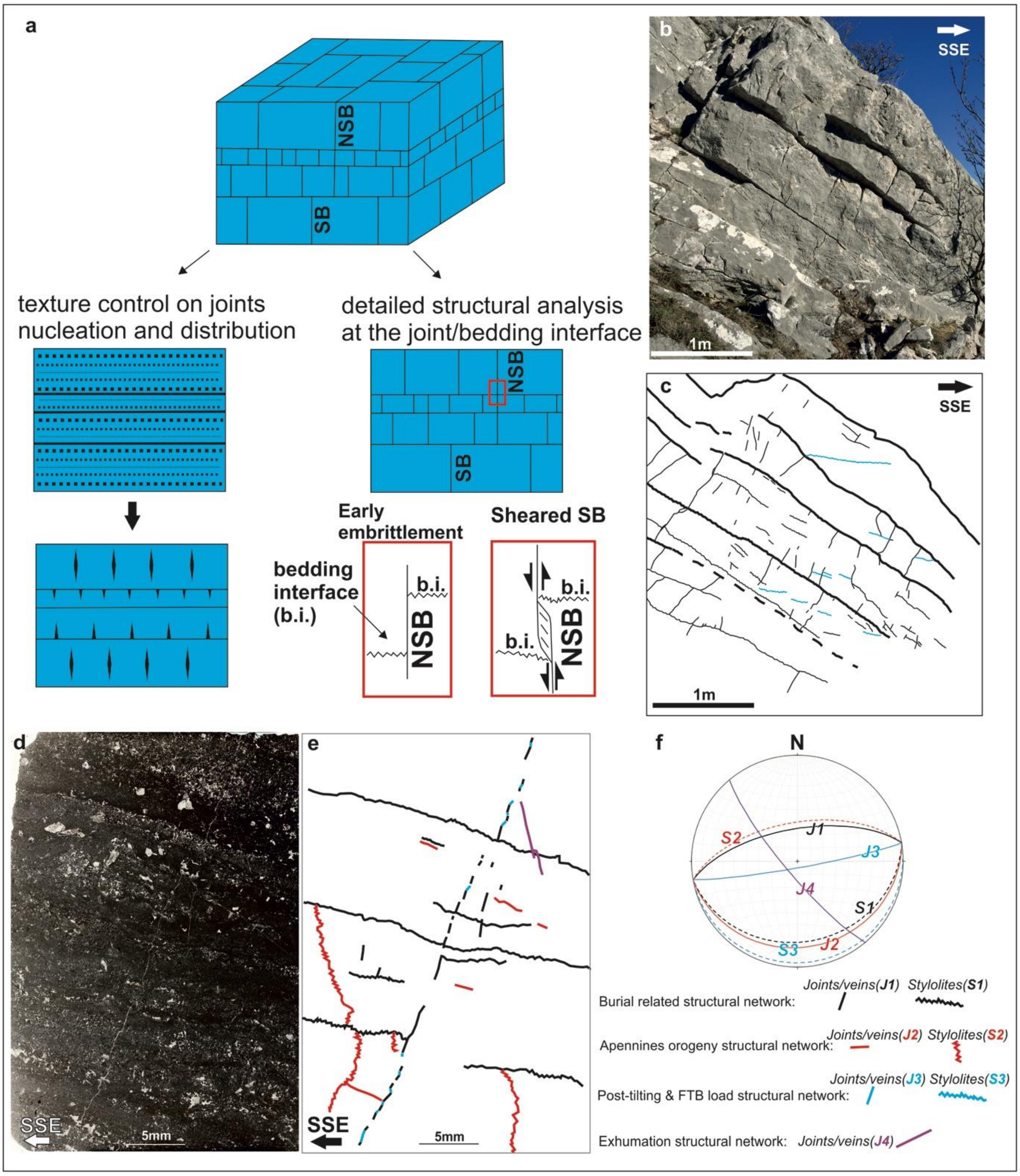


Fig.1 – (a) Schematic representation of the fracture architecture at outcrop scale, with a zoom showing the control exerted by the texture variation and the structural architecture of NSB fractures that crosscut primary heterogeneities. (b-c) Photograph and drawing of a portion of outcrop. (d-e) Photomicrograph and line drawing of the main structural elements recognized at a thin-section scale. (f) Low-hemisphere projection of the structural elements that are reported in c and e.

NOTES:

Quantifying fracture aspect ratios in reservoir-scale fractured carbonates

Richard R. Jones, Jonathan J. Long, Susan E. Daniels, David M. Oxlade.
Geospatial Research Ltd., Durham

Mean aspect ratios (fracture length to height relationships) are an important formation-specific parameter for modelling of fractured reservoirs, particularly when predictions have to be made using sparse sub-surface data. In outcrop it is generally not feasible to measure directly the aspect ratio of a fracture, since at least one of its dimensions will be censored at the outcrop surface. Ascertaining fracture dimensions from borehole data is even more problematic. To overcome this limitation in direct measurement of aspect ratios, we compare the height-intensity and length-intensity distributions from large fracture populations derived from sampling multiple outcrops within the same reservoir unit. We co-plot the two relationships on a single multi-scale graph, and estimate a representative aspect ratio from the relative position of the two distributions.

In this study we present data collected using a combination of traditional and modern geospatial methods, including 1D outcrop transects, digital photogrammetry, Lidar (terrestrial laser-scanning), satellite imagery, and georeferenced, scaled outcrop photos. The study is based on well exposed outcrops of Cretaceous strata that are direct analogues for producing reservoir units in nearby fields, in the Kurdistan region of the Zagros fold and thrust belt, NE Iraq. Over 74,000 fracture lengths and 8,500 fracture heights are analysed and used to quantify the range of representative aspect ratios per formation. The scale range over which the aspect ratios are characterised is from ca. 0.1m to 3,000m in length and ca. 0.01m to 100m in height, and therefore mitigates the need to upscale aspect ratios measured at outcrop scale for use in reservoir modelling.

Ackermann at al. (2001) describe how fault aspect ratios increase when propagation of the fault becomes vertically confined by mechanical layers. We infer that this also occurs during the development of other types of fracture, including tensional, shear and hybrid fractures in fractured reservoirs. Mechanical layers exist at all levels within the Kurdistan stratigraphy (i.e. individual beds to entire formations), and we therefore expect confined fractures of all sizes to have greater aspect ratios than unconfined fractures (> 2:1). Ackermann at al. (2001) report that when the fracture systems in their experiments became fully saturated, aspect ratios of 4.5:1 were reached. In Kurdistan (and other fractured reservoirs we have studied elsewhere), mean aspect ratios for fractures can be significantly larger than 4.5:1 in sequences with strong mechanical contrasts.

NOTES:

Upon the Representative Element of Natural Fracture Networks in Carbonate Reservoirs: Insights from Deterministic Discrete Fracture Network Models

Thomas D. Seers[1], Roberto Rizzo[2] & Talha Khan[1]
[1]*Texas A&M University at Qatar, Qatar*
[2]*Department of Geology and Petroleum Geology, University of Aberdeen*

It has long been recognized that natural fractures systems impart significant permeability within the upper crust. This is particularly significant for many carbonate reservoirs of the Middle East, with open mode fractures playing an integral role in the production of hydrocarbons therein. A significant challenge in these settings is to capture numerically the net fluid transport properties of the discontinuity network in an orthogonal grid, amenable to classical reservoir simulation. In practice, this is often achieved by building an explicit statistical representation of a fractured reservoir interval, whereby each individual fracture is modelled as a polyhedron, located in the object space using a random point process, with orientation and size drawn from a pre-defined parametric distribution (i.e. a discrete fracture network or DFN). Due to the computational overhead of solving flow equations directly upon large discrete fracture networks, these DFNs are usually upscaled to grid based porosity-permeability models, under the assumption of continuum like fracture network petrophysical properties (i.e. equivalent porous medium or EPM properties) at the selected grid block scale. This workflow is founded upon the assumption that there exists a scale at which the properties of discrete heterogeneities become statistically homogenous and immune to boundary effects to form an effective continuum medium. The scale at which this homogenization occurs is the theoretical *representative elementary volume* or REV of the fractured rock mass, and is specific to a given property of the rock mass in question (e.g. fracture intensity, porosity, permeability). However, in practice there is no guarantee that the REV of the modelled rock mass exists, and there remain considerable practical obstacles in deriving appropriate REVs for geologic fracture networks (and thus appropriate upscaling grid block dimensions). Here, this critical deficiency our current understanding of fracture network statistical behaviour is addressed with the aid of a novel outcrop constrained discrete fracture network (DFN) modelling framework, which enables near deterministic realizations of discontinuity architecture to be constructed using lidar or digital photogrammetry derived digital rock surface models. The validity of REV concepts to natural fracture networks is investigated by progressively growing a kernel around randomly seeded vertices of the parent outcrop model, and deriving per-vertex upscaled values of fracture intensity, porosity and permeability of the contained fracture array. This analysis is applied to naturally fractured analogues of major Tethyian carbonate reservoirs of the Middle East displaying varied mechanical styles (non-mechanically bound and mechanically bound fracture networks), allowing the impact of mechanical layering upon fracture network statistical homogenization to be investigated.

NOTES:

Dynamic Calibration of the Shaikan Jurassic Full-Field Fractured Carbonate Reservoir Model Through Single-Well Drill Stem Test (DST) and Multi-Well Interference Discrete Fracture Network (DFN) Simulation

Neil Price[1], Paul La Pointe[1], Chunmei Shi[2] and Kevin Parmassar[1]
[1] Gulf Keystone Petroleum Ltd., London, UK
[1] Golder Associates Inc., Redmond, WA USA

The significant hydraulic contrast between fractures and matrix in fractured carbonate reservoirs, and the heterogeneity in the fracture systems themselves, make predicting reservoir scale flow and fracture pore volumes more uncertain than in formations or reservoirs in which fractures play a less important role. The hydraulic behavior of the fractures in a fractured carbonate reservoir is a function of fracture attributes: type, intensity, size (length, height), aperture, orientation, and intrinsic permeability. All of these attributes influence the scale and degree of connectivity.

The goal of this project was to develop a geologically based full-field DFN fracture model whose geometry and hydraulic properties could be constrained by a wide variety of geological, geophysical and dynamic data prior to use in a full-field finite difference simulation.

The first step was to create a conceptual model of the origin and controls on natural fracture intensity, orientation, shape, size and aperture that could then be implemented as a Discrete Fracture Network model. Secondly, a series of well-scale DFN models were created from the implementation of the conceptual model. In these models, fracture aperture was correlated to fracture size, such that the resulting fracture model matched the aperture range obtained from core and image logs. Fracture permeability was correlated to fracture aperture using a Power Law relation analogous to the Cubic Law, but with a reduced exponent to account for fracture roughness effects on flow. The correlation between aperture and permeability was adjusted for an initial DST until a match to the pressure derivative was obtained.

As an additional check on the DFN model fracture aperture and permeability parameterization, a DFN model was created to simulate an interference test. Interference involves the response of a much larger reservoir volume than a DST test, and so may less subject to local geological variations in the fracture system than a DST test. The DFN model matched the observed pressure interference data with the parameter values derived from the DST matching, which suggests that the parameterization derived from the DST matching is likely to be representative of large reservoir volumes rather than local conditions only. Moreover, the fracture porosity was estimated from the interference test results for a range of reasonable values of fracture and total compressibility. The aperture-compressibility product (*eC*) was calculated from the interference tests. This was used then in conjunction with selected combinations of fracture and total compressibility, formation thickness and fracture aperture to estimate fracture porosity. The calculations produced estimates of fracture porosity similar to those independently derived from the DFN model, further validating the hydraulic parameterization of the DFN model.

A final step was to upscale the dynamically calibrated DFN results (fracture porosity, directional permeability tensor, and sigma factor) onto a coarser full-field scale simulation grid cells. Preliminary simulations show reasonable matches with pressure history, without having to resort to changes in reservoir properties near any of the wells in most cases

Overall, this workflow showed the power of building a full-field reservoir model of a complex fractured carbonate system at various scales, from single well to multi-well sector DFN simulations, honoring with confidence the geological fracture concept and its numerical implementation, and in developing a robust hydraulic calibration of the fracture model prior to upscaling to the full field.

NOTES:

Modeling dynamic behavior of fracture corridors from time lapse Electrical Resistivity Tomography (ERT) experiments. Application to the Calvisson Quarry (SE France)

Hamlaoui S1; **Gauthier B.D.M.2**; Lamarche J.1; Quesnel Y.1 ; Uehara M.1 ; Conesa G.1
1 Aix Marseille Univ, CNRS, IRD, Coll France, CEREGE, Aix-en-Provence, case 67, 3 place Victor Hugo, 13331 Marseille (France)
2 Total EP, 2 place Jean Millier, 92078 Paris-La Défense Cedex, France

Introduction and concept
In Naturally Fractured Reservoir studies, outcrop analogues are often used solely to understand the genesis, geometry, properties and distribution of fractures in relation to scale and mechanostratigraphy, i.e. the static aspect of the fracture network. However, in subsurface reservoirs, it is the dynamic aspects which matter, i.e. the flow network. Yet the relationships between fracture and flow networks is far from simple and hardly predictable. The aim of this study is to present a simple method to understand the contribution of different fracture scales to flow through time lapse ERT profiles. The concept is applied in the Calvisson quarry (SE France) where a dense diffuse fracture network and several fracture corridors affect carbonate rocks at the scale of a reservoir simulation cell. There, we acquired several 2D ERT profiles at 24/48/72 hours after a heavy rainfall to see how the fracture network is electrically responding to the water saturation and its variation. We also measured the resistivity at the sample scale in order to understand the upscaling effects. Based on structural and LIDAR survey, we realized a 3D structural model of the horizon and fracture corridors pattern. Then, we define a relationship between resistivity/conductivity, saturation and permeability the goal of which is to populate a 3D model of the quarry in fractures (DFN) and in dynamic properties.

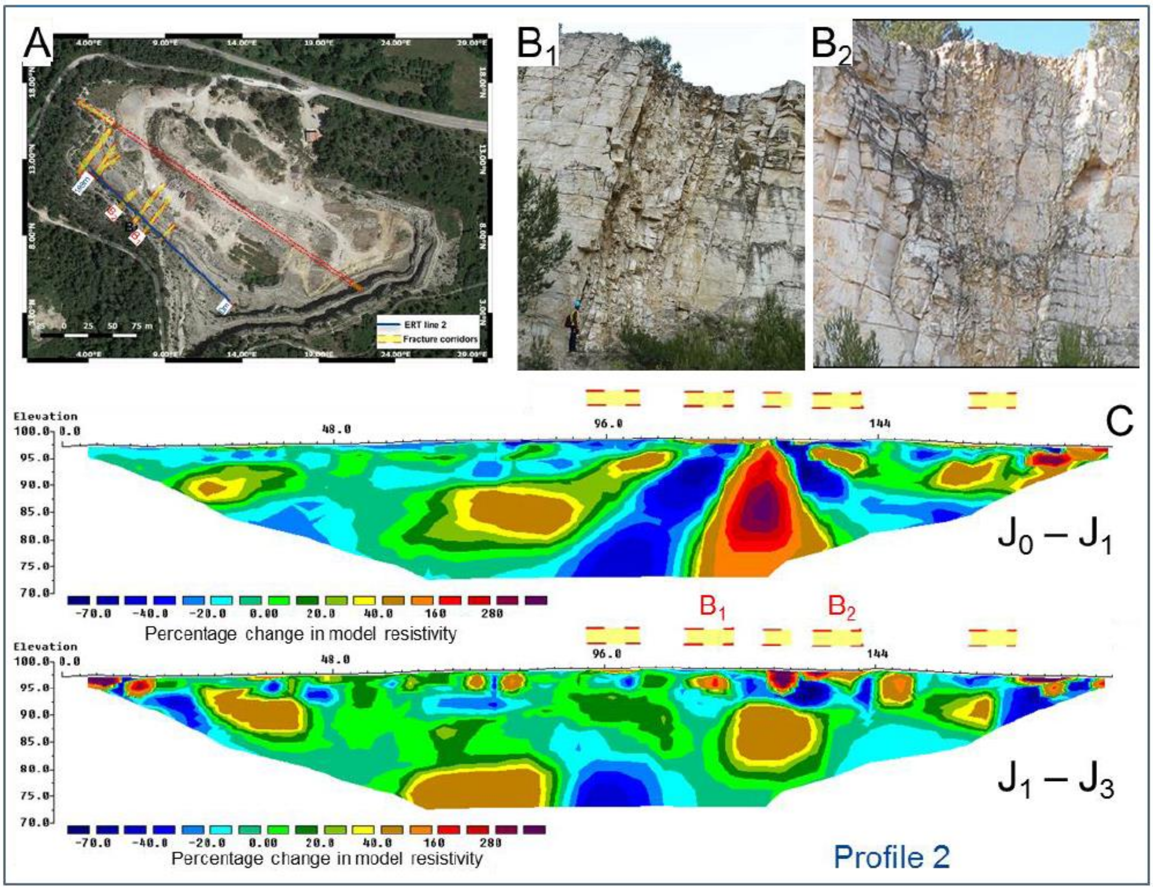
Geological context and fracture pattern
The Calvisson quarry is located on the western border of the Camargue Basin (SE-France). The quarry exposes Hauterivian marly limestones deposited in the so-called South East Basin. The average matrix and K are 10% and 2.3mD, respectively. The quarry exhibits monoclinal beds gently dipping ~15°N. The fracture network in Calvisson Quarry has been studied by Bisdom et al. (AAPG 2012) and Lamarche et al. (EAGE 2017). It is composed of no strata-bound diffuse fractures and localized FC’s. Two diffuse fracture sets trend N120° and N045° (+/- 10°), both following normal distributions in spacing (P10 range from 0.4 to 2m-1) and height. FC’s have similar strike and are spanning the entire height of the vertical quarry walls in most cases, so that six NE-SW-trending FC's can be traced through multiple quarry extraction levels suggesting that their vertical extent is more than 20m whereas their lateral extent is at least 25m while their spacings range from 7 to 21m (Fig. A). Since only two NW-SE corridors outcrop in the quarry and are possibly linked (Fig. A), height is assumed to be similar whereas length could reach 350m while their spacing is more than 200m.

Data acquisition and processing
Three NW-SE and one NE-SW oriented profiles are, respectively, 190m in length with 3m electrode spacing giving a 25m investigation depth, and 130m in length and 2m electrode spacing giving a 17m investigation depth. The acquisitions were made during a relatively dry period (J0) and during three days (J1 to J3) after a 7 days long rainfall with a cumulative rate of 66.4 mm. Rock plugs were sampled within an outside the corridors to measure: i) petrophysical properties (porosity, permeability, Vp, micro-fracking density) and ii) resistivity evolution at different saturation levels. Finally, scanline measurements of fracture density were also performed to calibrate the LIDAR model.

The observed apparent resistivity data were processed to obtain 2D electrical resistivity images by iterative inversion, after removing noisy data points and including the post-treated DGPS positions. We modelled the percentage of resistivity change with time and compared it with the fracture network (Fig. C). Ultimately, a calibration with sample measurements was made. The 3D fracture network was then modeled using the LIDAR data calibrated to the 2D scanlines. The flow network is assessed through a permeability- resistivity/conductivity transfer law and its adequacy with fracture density is evaluated resulting in a dynamic 4D modeling of matrix, diffuse fractures and fracture corridors permeabilities.

Interpretation

Preliminary results as 2D electrical resistivity images at the date of the abstract show the distribution of resistivity which varies approximately from 200 to 3000 Ω.m in the same homogenous facies. The high resistivity values reflect the high resistivity of the limestone matrix which is in the same order of values with samples resistivity between 1000 to 3000 Ω.m, hence corresponding to non-fractured matrix. Low values correspond to fractured zones. Time lapse images of percentage change in resistivity show an increase in the resistivity in fractured limestone zones with time (negative, blue values in Fig. C), due to water flow inside the fracture network and its desaturation, whereas the non-fractured zones show a decrease in the resistivity related to the percolation of water inside the pores and the variation of sinuosity generating the enhancement of conductivity (positive, green to purple values in Fig. C). However, the detailed variations with time appear also to be complex and nonlinear hence reflecting the complex flow relationships between the various fracture scales and the matrix.



***A**: Position map of ERT profile 2 relative to Fracture Corridors; **B**: examples of corridor outcrops crossing through profile 2; **C**: % of resistivity change from dry survey to wet day 1 (J0-J1) and from wet day 1 to wet day 3 (J1-J3).*

Conclusion and way forward

Simulating the permeability of multi scale fracture networks from continuous ERT surveys is a promising approach to quantify the partitioned contribution to the fluid flow of diffuse versus clustered fractures at reservoir scale. This study will also propose resistivity to permeability transfer laws. The results will help to better catch the fracture heterogeneity and multi-scale pattern while simulating fluid flow in models of naturally fractured reservoirs.

So far, the limitations of this experiments are the long-time laps between ERT records and the property extrapolation in 3D from 2D images. The experiment could be extended to 3D surveys with higher frequency or continuous resistivity record.

NOTES:

Insights from a multi-disciplinary fracture study of the Zechstein of NW Europe

Susie E. Daniels[1], Jonathan J. Long[1], Maurice E Tucker[2], Michael J Mawson[3], Jon G Gluyas[2], Robert E Holdsworth[2], Richard R. Jones[1]
[1] *Geospatial Research Ltd., Durham, UK*
[2] *Dept. of Earth Sciences, Durham University, UK*
[3] *Independent*

Production from Zechstein carbonates in the UK, Norway, Poland and Netherlands is significant today and has been important since UK offshore oil production began in 1975. Fracture permeability is commonly significant for production from such Zechstein carbonate reservoirs. Sometimes fracture permeability is higher or lower than anticipated, with significant impact for well (and field) productivity. This can also be associated with early water production, a relatively common occurrence for Zechstein carbonate reservoirs. Understanding the fracture stratigraphy, in particular identifying any units which have pronounced fracture properties (either a tendency to retard fractures and act as a mechanical barrier, or units with a tendency to be highly fractured) will be useful in optimising development.

A study of fractures in Zechstein carbonates from outcrops in NE England was completed in 2016. The Zechstein carbonates are a complex reservoir, and have been subject to a multitude of complex processes that began during deposition, and continued through burial and exhumation. A simple structural study of the fractures would not have been sufficient to provide a useful understanding. To unravel the fracture stratigraphy it was necessary to have a comprehensive understanding of the processes that affected the study sites, before being able to clarify the impact they have on fracture behaviour. The study builds on extensive multi-disciplinary analysis of these world-class Zechstein carbonate outcrops, with collaboration across the disciplines of sedimentology, sequence stratigraphy, fracture network characterisation, and structural analysis.

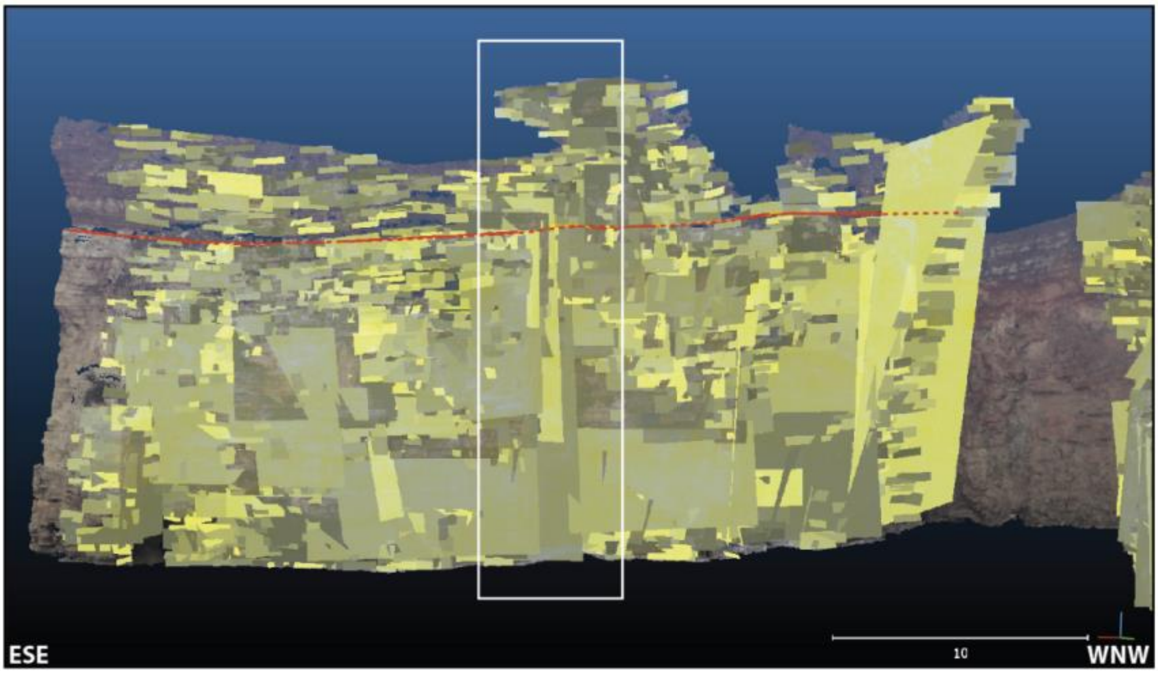


Fig.1 Lidar point cloud with interpreted fractures (auto-picked and manually validated). White box delineates the same area of outcrop as the box in Fig. 2.

The outcrop fracture study of Zechstein carbonates (Z1 - Z3) from was organised by facies, diagenetic history, tectonic setting and lithology. Understanding the facies within the sequence stratigraphic context enables application of the predictive fracture model across the basin. Outcrop fracture characteristics were evaluated alongside subsurface core and production performance to better understand how these factors impact permeability and well performance.

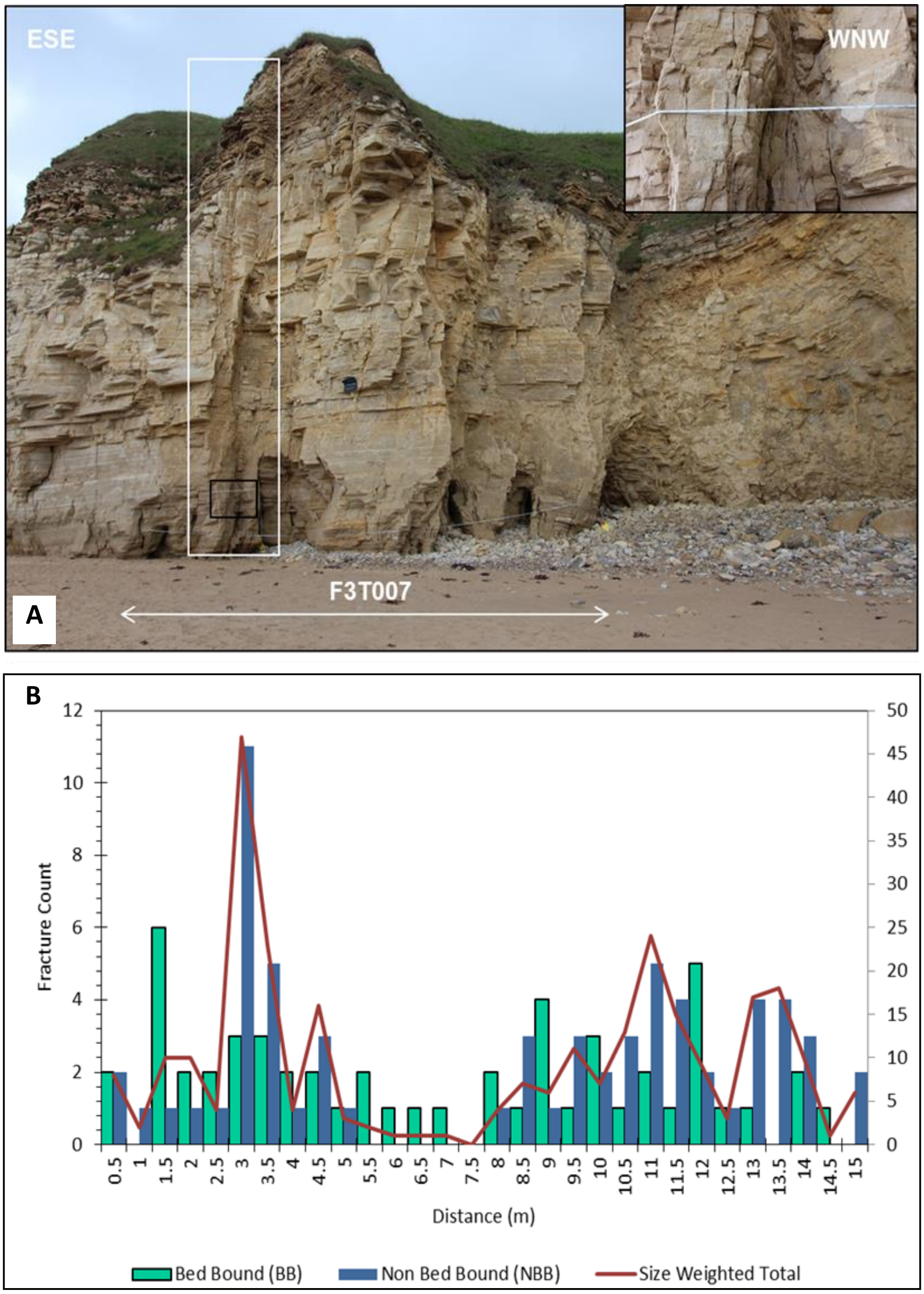


*Fig.2 Fracture corridor within the Roker slope facies. **A** white box shows area of vertically persistent fractures. Black box shows the location of the inset image. **B** Fracture density per 0.5 m bin (along transect 'F3T007'). A peak in intensity of non-bed-bound fractures occurs at the point at which the inferred fracture corridor intersects the transect at 3 m.*

NOTES:

Day Two:
Session Four: Fractured Basement Reservoirs

KEYNOTE: Characterising the fracture properties of Lewisian Gneiss basement reservoirs Rona Ridge, West of Shetland

Robert Trice[1], Mathew Thompson [1], Bob Holdsworth[2], Ken McCaffry[2] , Kristian Hardman[2]
Steve Rogers[3]
[1] Hurricane Energy Plc ,
[2] Rock Mechanics Unit Dept. of earth Sciences Durham University
[3] Golder, Suite 200 - 2920 Virtual Way, Vancouver, British Columbia

Fractured basement reservoirs are a globally known, but underexploited type of hydrocarbon resource with producing fields worldwide. They are still poorly understood by industry in the UK which has historically focused on clastic reservoirs that proliferate the UKCS. With increasing basin maturity explorers are evaluating new UK exploration plays of which the fractured basement play of the Lewisian Gneiss Complex (Lewisian Gneiss) is an example.

Lewisian Gneiss is a naturally fractured formation of Archean crystalline crust that outcrops in Scotland and the Outer Hebrides and underlies most of the offshore Faroe-Shetland Basin. The Lewisian Gneiss has been penetrated by several exploration and appraisal wells West of Shetland, especially along the NNE-SSW trending Rona Ridge, which lies in the uplifted footwall of a series of Mesozoic normal faults. These penetrations have led to hydrocarbon discoveries of which Lancaster is the first UK fractured basement field to be approved for development. There have been a series of material technical challenges that have needed to be overcome before the final investment decision, to fund the field development, was granted. Of these challenges the identification and quantification of effective fracture porosity and permeability was of particular significance. This significance is rooted in the nature of the reservoir which is considered to be a Type 1 Fractured Reservoir, in that all effective porosity and permeability is attributable to a hydrodynamic natural fracture network.

This presentation considers how the hydrodynamic fracture network has been identified and quantified at Lancaster. These observations will be compared to geological processes seen elsewhere along the Rona Ridge and in onshore analogues in Scotland and elsewhere to explain how effective fracture porosity has been preserved, distributed and modelled within the Lancaster reservoir. A selection of wireline, logging whilst drilling, core and drill stem test data sets from Lancaster and other West of Shetland basement discoveries will be presented and compared to outcrop data from Scotland and the Outer Hebrides, to convey the presentation’s observations and conclusions. The presentation will conclude with a summary of the fracture characteristics that are considered to be representative for the hydrodynamic network so far penetrated in the Rona Ridge Lewisian basement.

NOTES:

Fault Void Fills: Internal architectures of near-surface faults and implications for hydrocarbon reservoirs

Kit Hardman[1], Bob Holdsworth1, Ken McCaffrey[1], Eddie Dempsey[2]
[1]*Durham University*
[2]*University of Hull*

During early rift development, major basin-defining faults may be connected upwards into open fissures that are subject to near-surface processes, such as sedimentation, surficial fluid circulation and in some cases, hydrothermal mineralisation. The way in which such fault voids are influenced by these processes can have major implications for their fills and long-term fluid transport properties of their associated fracture systems in the subsurface. These partially filled systems can be particularly significant in otherwise low permeability carbonate and crystalline basement fractured reservoirs and are strikingly common in the uplifted footwalls of large basin-bounding normal faults.

Recent numerical and analogue modelling studies have shown how near surface (<1-2 km depth) fracture cavities and their fills collapse, grow, and deform as fault systems develop. By examining natural examples of these fault void fills from a variety of locations and comparing them to examples sampled in sub-surface cores, we aim to test some of the predictions of these models. The fault voids studied here vary in scale from micro-cracks, to decametre-wide fissures and in-fills. Despite the variety of different aspect ratios and apertures, fault voids consistently demonstrate interconnectivity and pervasive (total to partial) infilling of materials. For example, sedimentary material that is passively deposited into open cavities, has been shown in some cases to occupy up to 45% of the total rock volume, profoundly altering the expected mechanical and fluid transport properties of the host rock unit.

The fault void fills themselves record valuable information on the regional structural evolution and preserve fault-rock textures that can give important clues regarding fluid migration processes. Many existing models of mineralised void fills assume that a fault-valving mechanism is predominant, but widespread observations of cockade and partial cavity-filling mineralisation textures demonstrate that in the near-surface environment, cementation rates do not keep pace with fracture opening, so that open cracks can remain permeable to fluids in the long-term. The preservation of injected sediment slurries is also widely recognised suggesting that active seismicity may also be important in controlling fracture development and fluid migration and redistribution in the subsurface.

In this talk we will illustrate these features using 2 key onshore study areas: fractured Devonian limestones in SW England hosting Permo-Triassic sandstone fissure fills and carbonate mineralisation, 2 and Late Carboniferous tonalites hosting Miocene sandstone fissure fills in Calabria, Italy. These areas are then compared to sub-surface examples of cores recovered from fractured Precambrian Lewisian basement from several locations along the crest of the Rona Ridge, west of Shetland. Fracture fills from both study areas, and the offshore cores show very similar geological relationships and textures. The Rona Ridge examples are known to host significant volumes of oil related to the Clair and Lancaster fields, two of the largest remaining oilfields in the UKCS. The implications for other fractured basement and carbonate reservoirs in the UKCS and worldwide will be discussed.

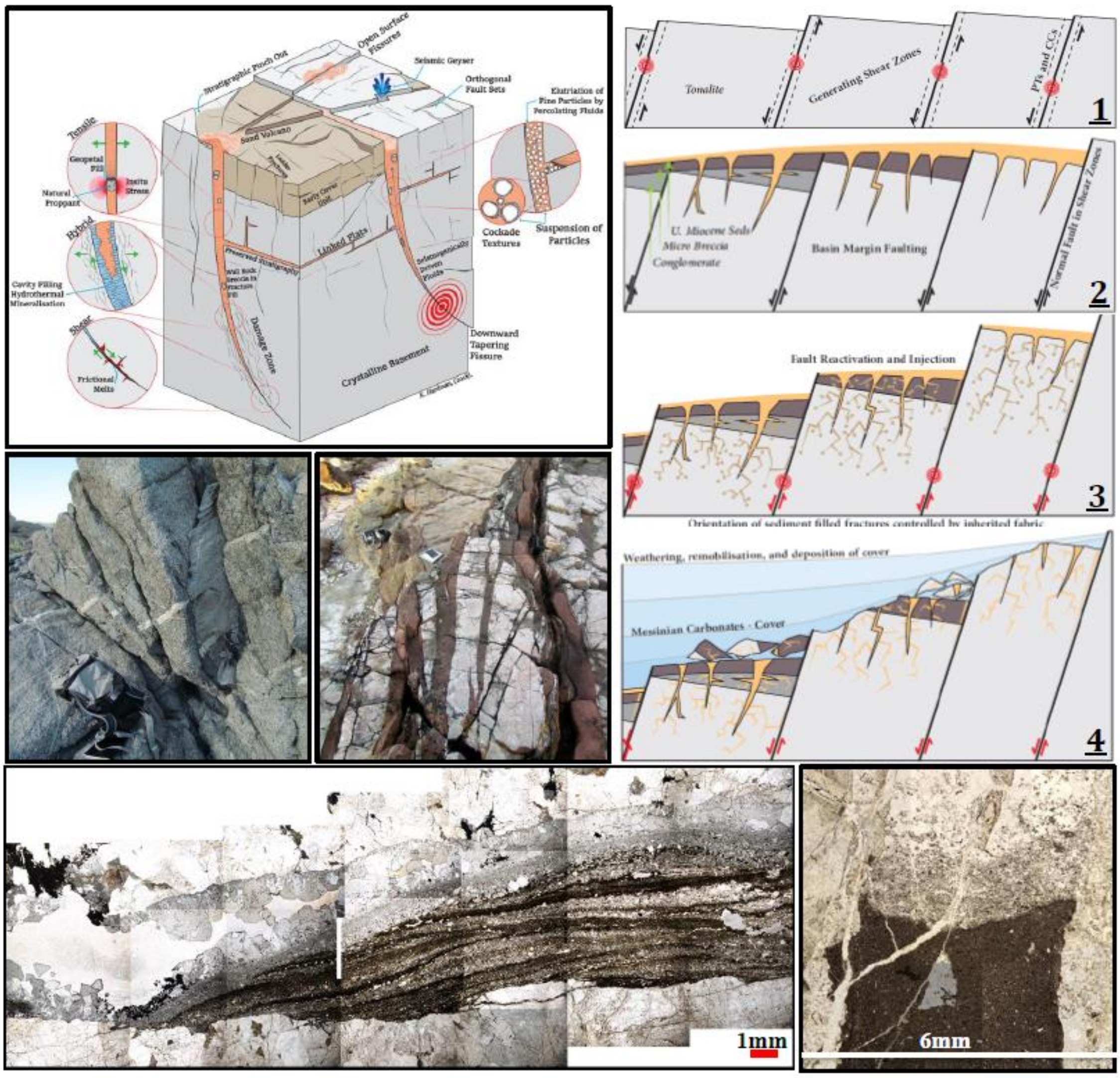


Figure: Conceptual models, field photographs, and photomicrographs of natural examples of near-surface faults. These faults repeatedly preserve large volumes of sediment within fracture hosted cavities, which have been shown to contain hydrocarbons.

NOTES:

Where is the fresh water coming from?

Carl Fredrik Gyllenhammar, PhD
CaMa GeoScience, Stavanger

In 2016 Hurricane drilled the pilot well 205/21a-7 and produced 6300 barrels of oil and water per day from the basement. The drilling brine was at 56 000 ppm salt concentration, while the water sample from the DST showed 18 500 ppm (RPS, 2017). The question is why the basement water is so fresh?

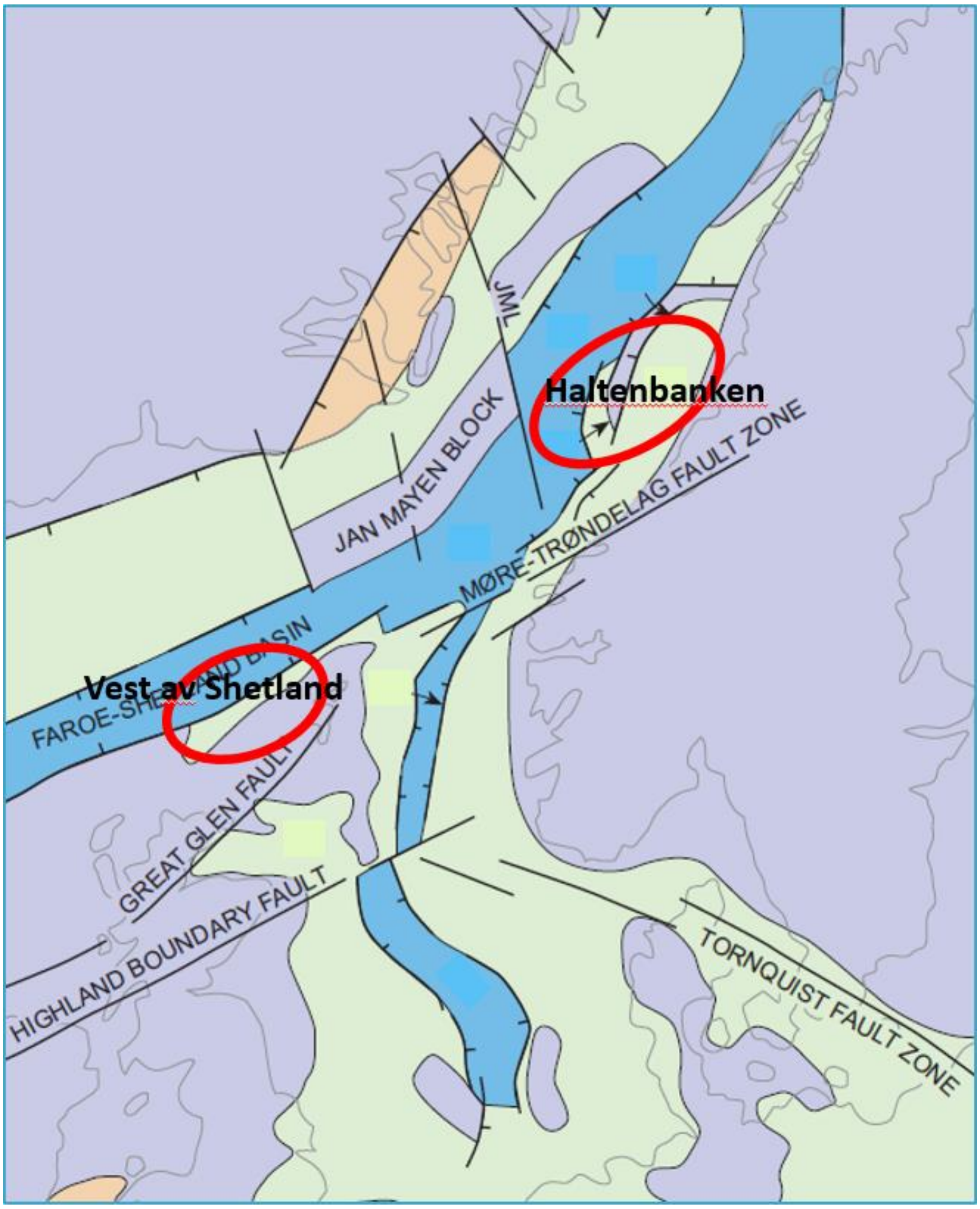
Many studies have discussed the large variation observed in the salinity of the formation waters in the North Sea, Norwegian Sea and in the Barents Sea. In the Barents Sea the formation waters vary from close to fresh in the Pingvin well (7319/12-1) and up to up to 440 000ppm only 300km south east in well 7220/5-2.

Common sea water has about 35 000 ppm salt. There is much written about the salinity of the paleo seas. Very likely, it has not changed much. In periods without any icecaps, the salinity may have been reduced by about 10% compared to today. It is therefore expected that the sea water from Triassic times until now have varied between 30 000 to 35 000 ppm. After deposition the formation water have been exposed to mineral dissolution and precipitation, but more important to large salt deposits such as salt diapirs, salt walls and salt layers. The maximum salt saturation is a function ion composition and temperature. If only NaCl is in the solution the saturation point is about 440 000ppm. NaCl solution is quite unique as the saturation vary very little with changing temperature. In most formation waters there are at least one salt pair with a common ion such as KCl and NaCl. In those cases, the saturation point will be less than 440 000ppm (Warren, 2016). One should therefore expect that the salinity in the formation water would vary from 30,000 ppm as the lower end and up to saturation at 440 000 ppm. The puzzle is how can the salinity get less than about 20 000ppm? Is there a fresh water source?

Hurricane has found a 1156m oil column in the basement, the Roan ridge, west of Shetland. The Roan sand onlaps the basement. A direct conduit between the fluid in the sediments and fluid in the basement fractures. Oil and gas can flow into the basement and the water trapped in the basement out into the sedimentary layers.

There are similar basement ridges and basement horst structures on the Norwegian shelf. The structural map show similarities between the area west of Shetland and Haltenbanken, specifically the Roan Ridge and Revfall fault complex, where the basement forms several horst structures (fig.1). Just west of the Revfall fault complex is the Alve field. The discovery well, 6507 / 3-1 where the Jurassic the formation water salinity is as low as 14 000 ppm. The calculation of the salinity is done by log analysis, not a water sample.

An interesting article in 2005 by McCartney, compiles all information published about the formation water in the Norwegian sector. They point out that low salinity water has been observed in some discoveries such as, Fram, Ormen Lange, Edda, and Veslefrikk. These observations are based on analysis of sampled water. Previous work suggest that the salinity vary from 2 500 to 212 000 ppm (McCartney and Rein, 2005). Their analysis of water shows that where an input of ancient methoric water. Fresh water that cannot have been sourced from overlying glaciers during the last 2.4 million years.

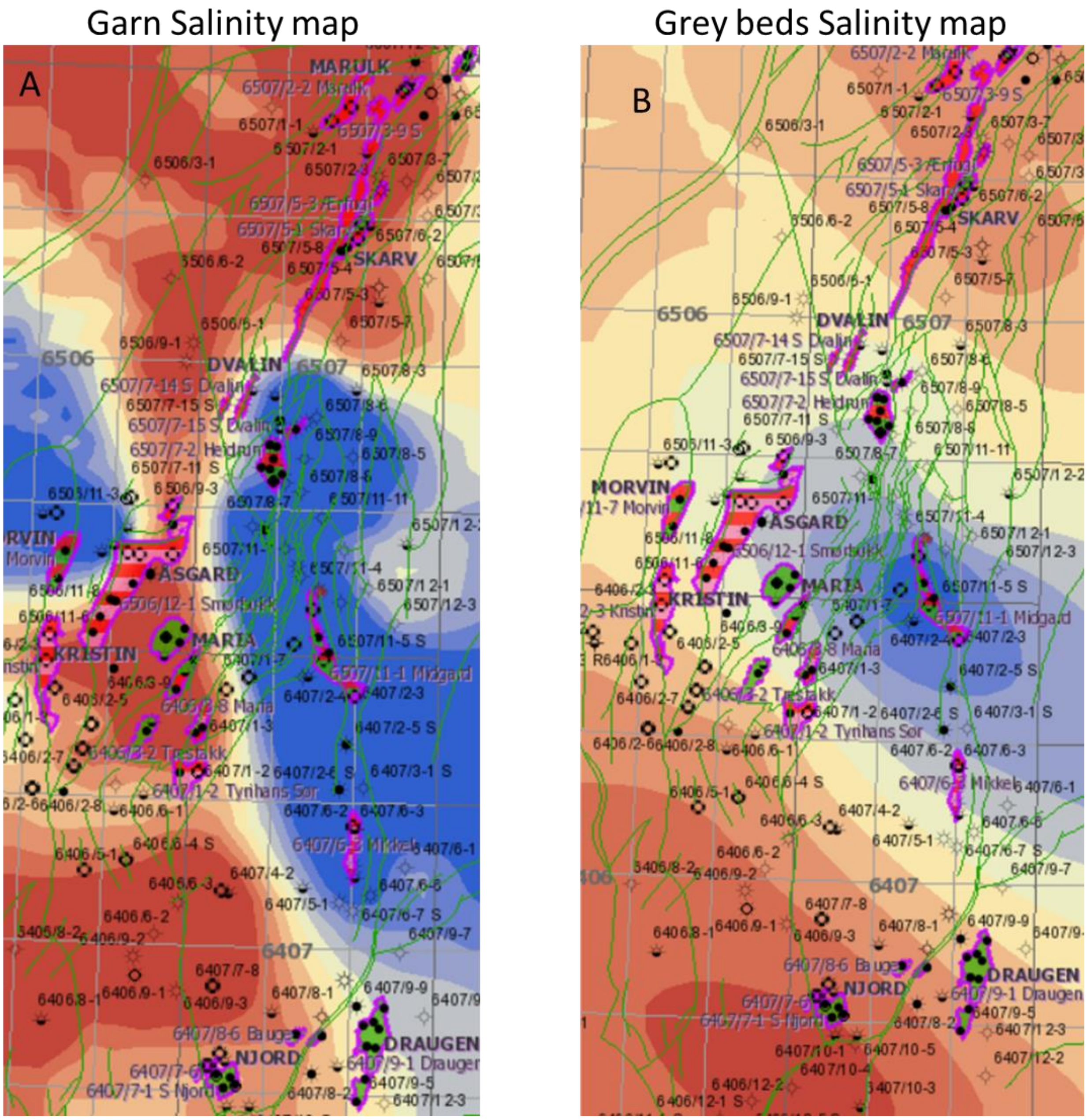


Figur 1. Structural relationship between Roan Ridge west of Shetland and the Revfall fault complex at Haltenbanken.

The challenge with using water sample analysis is that it is very few sample points. Most pressure test samples such as RFT samples are too contaminated by drilling fluid. Only samples form full production tests (DST) gives a close to contaminations free sample.

The alternative method is to calculate the resistivity of the water (Rw) using wireline logs. The petrophysical method. In this study more than 600 exploration wells have been analyzed which have enabled generation of detailed salinity maps (fig 2). Some petrophysical software's calculate the Apparent Rw (Rwapp). Rwapp is the resistivity of the formation water (Rw) that will make the formation 100% water saturated (Sw = 1). The corresponding equivalent concentration of NaCl (salinity) is then calculated. The salinity data was loaded into ArcGIS and contoured using a simple Kriging equation.

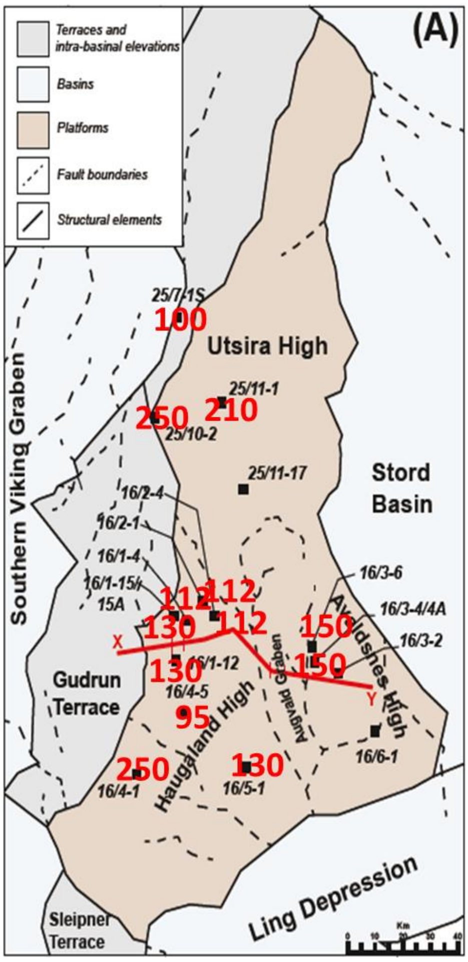
In many cases it is difficult to pick the correct Rw for one zone. The salinity map is a good guide but must be based on a dense grid. The Haltenbanken salinity map is based on 204 interpreted wells. It is in particularly where the salinity is very low, it is difficult to find the correct Rw. Based on this study not only the Alve field, but Dvalin (Zidane) and Åsgard field have a quite fresh water zone (fig.2).



Figur 2. Map A to the left is the Jurassic salinity map and map B is the Triassic salinity map. Blue is high salinity while dark brown is is lower salinity.

On the Norwegian Continental Shelf bedrock of pre-Devonian age are regarded as basement in a petroleum-geological context (www.npd.no). 72 Norwegian exploration wells have penetrated basement (56 wells in the North Sea, 8 in the Norwegian Sea and 8 in the Barents Sea). Most of these were drilled on structural highs with depth to top basement quite evenly distributed between 1200 and 4000m. The thickness drilled have generally been in the order of a few meters. Several wells have however drilled more than 100m of basement rock: 2/6-3 (142m), 16/1-4 (146m), 16/1-5 (195m), 16/2-5 (488m) 35/3-2 (233m) and 6306/10-1 (207m).

In 2009 Lundin found oil in the basement with 16/1-12 within the Edvard Grieg field. 16/1-15 drilled at the Tellus prospect found good reservoir in altered and fractured crystalline rocks. This was followed by a study of 18 basement cores from the Utsira High (Riber et.al., 2015). At 12 of the well locations it was possible to date the sedimentary layer onlapping the basement. The oldest sediment cover dates to 250 m.y while the youngest at 95 m.y (fig.3). Showing and age span from 250m.y. to 95m.y. This is time equivalent to the onset of the Permo-Triassic rifting. Suggesting that the basement between Norway and the UK was exposed to rifting as well as being airily exposed to meteoric water and weathering. The result being a fractured basement initially filled with mostly meteoric water and mixed with sea water.



Figur 3. In red is the age (m.y.) of the sedimentary layer that onlaps the underlying crystalline basement.

This study shows a correlation between deep to basement and salinity (fig. 2). The salinity is clearly lowered with depth. The fields that have quite fresh water sits either on or laterally close to a basement high. I therefore claim that there is a powerful freshwater source in the North Sea, the Norwegian Sea, the Barents Sea and the West of Shetland and the source is mainly the fluid trapped basement fractures. That is what McCarter referred to as "Ancient Meteoric Water."

The Barents Sea is somehow different as there is probably a freshwater source from the ice cover during the last 2.4 million years as well.

Low saline waters are found in reservoir rocks that are in direct contact with the basement. It is also likely to find hydrocarbons accumulated in the basement highs where gas, oil and water can flow freely between a permeable sedimentary layer that onlaps the basement. There are several opportunities for new discoveries in the basement. Not only along Revfall fault complex, but also east of Agat, Dvalin, Åsgard and several places in the Barents Sea, and in the area of Edvard Grieg and Johan Sverdrup.

It is important to realize that oil and gas have migrated into the basement. No new source concept is postulated! And finally, the basement heights that contain low salinity water and/or hydrocarbons must be the best storage space for CO_2 and a freshwater source for water injection in EOR projects.

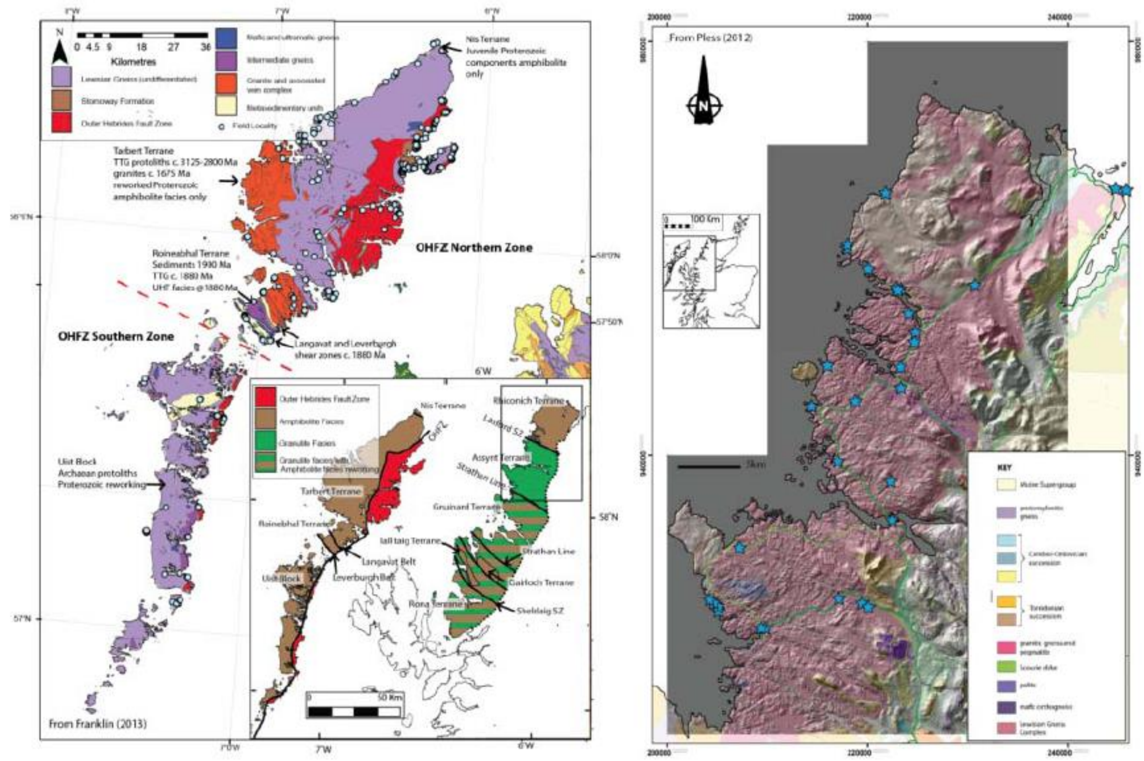
NOTES:

It’s a wee bit cracked: characterization of basement-hosted fracture systems, NW Scotland

Ken McCaffrey & **Bob Holdsworth**
Department of Earth Sciences, Durham University, Durham, UK, DH1 3LE.

Oil reservoirs hosted in fractured Neoarchean crystalline rocks might seem an unlikely target to pursue but recent successful appraisal of the Lancaster and Clair fields and associated parts of the Rona Ridge shows that there are significant accumulations in the basement offshore in the Faeroe-Shetland basin. This growing evidence has spurred a need to understand the nature of basement-hosted fracture systems in the nearest onshore analogues systems exposed in NW Scotland. Structural analysis of onshore-offshore fracture fills suggests that near-surface, rift-related fissure formation and sesimogenic faulting in strong basement lithologies of the Rona Ridge allowed pervasive influx of sediment fills into fracture systems as well as driving fluid flow and triggering hydrocarbon migration. Here, a recent reanalysis of fracture attribute datasets collected from the onshore Lewisian Complex is presented and their implications for basement reservoir development is discussed.

Figure



Datasets were collected in the field from a variety of natural exposures (mainly in well exposed coastal settings) using 1D line, 2D area sampling and 3D virtual outcrop sampling methods. The initial studies focused on orientation, size (aperture, length) and spatial characterization whereas more recent work has concentrated on the topological characteristics of the fracture systems. Our database contains c. 100 individual datasets which were chosen because they sample the various fracture systems that formed from Proterozoic to Mesozoic times in a range of transtensional, transpressional and rift settings (see Pless (2012) and Franklin (2013) Durham U. PhD theses).

Aperture/Intensity data for all regions are best described by power-law scaling. In general, fracture aperture, length and spacing attributes from onshore analogues compare well to Clair seismic, well log and core data. The best match to Clair basement comes from datasets from regions to the north of the Paleoproterozoic Canisp shear zone. This part of the Assynt terrane has limited pervasive Paleoproterzoic overprint and is thus likely to be the part of the mainland Archean that is most similar to the Neoarchean basement in the Rona Ridge where Proterozoic (Laxfordian) overprinting is largely absent (Holdsworth et al. submitted). 40 topology analyses were carried out on a range of onshore and offshore samples including drillcore, outcrop images, seismic attribute and regional datasets.

Figure 3 shows a summary of the topology values that have been obtained from Rona Ridge core and seismic attribute data, and the Assynt terrain. All basement samples show connected fracture networks with CB values >> 1 which is the threshold CB (connections per branch) for a connected network. Our study – which is based on the largest basement fracture attribute study ever assembled - shows that basement-hosted fracture systems are highly connected over at least 5 orders of magnitude length scale. Datasets of this kind help to reduce uncertainties in the development of subsurface models that are created to determine drilling locations and quantifying the likely economic returns in terms of hydrocarbon production and resource in fractured basement fields such as Lancaster and Clair.

Figure

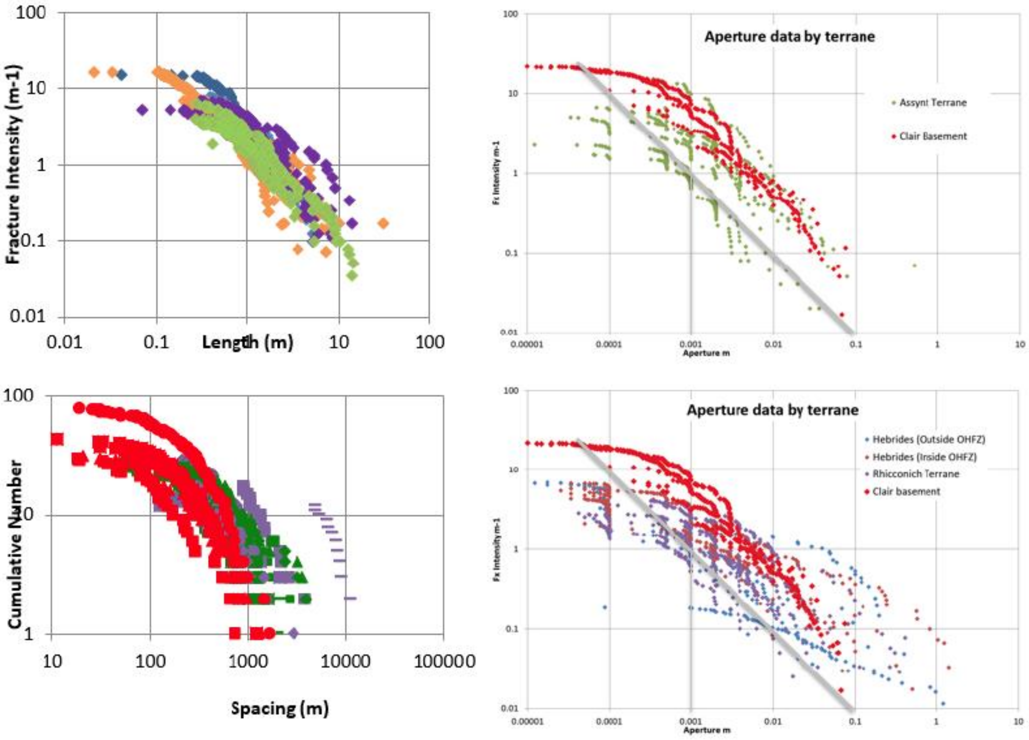


Figure 2 Clair basement cores datasets (red) show a good match to outcrop-scale datasets from Assynt terrane (green). Show a poorer match (in scaling) to Hebrides and Rhiconnich terrane on the Mainland (blue/purple). Attributes Length/Spacing/Aperture shown. Length data not available for Clair as samples came from drill core.

40 topology analyses were carried out on a range of onshore and offshore samples including drillcore, outcrop images, seismic attribute and regional datasets. Figure 3 shows a summary of the topology values that have been obtained from Rona Ridge core and seismic attribute data, and the Assynt terrain. All basement samples show connected fracture networks with CB values >> 1 which is the threshold CB (connections per branch) for a connected network. Our study – which is based on the largest basement fracture attribute study ever assembled - shows that basement-hosted fracture systems are highly connected over at least 5 orders of magnitude length scale. Datasets of this kind help to reduce uncertainties in the development of subsurface models that are created to determine drilling locations and quantifying the likely economic returns in terms of hydrocarbon production and resource in fractured basement fields such as Lancaster and Clair.

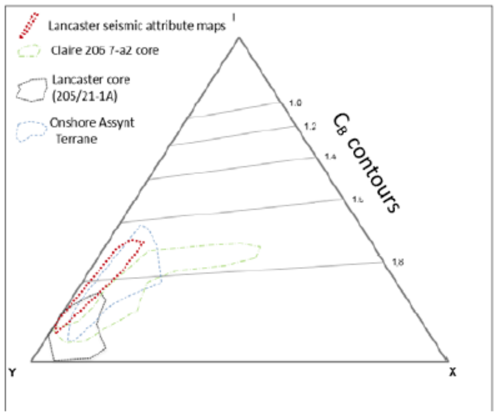


Figure 3 Topology analysis for onshore and offshore basement (n = 40 analyses).

NOTES:

Characterization of a basement fracture system, Cheviot field, North Sea

T. Needham[1], N. Odling[2], P. Whailing[3], P. Milner[3], J. Ridings[3], G. Phillips[2] & R. Knipe[2]
[1] Needham Geoscience Limited, Ilkley, UK
[2] School of Earth & Environment, University of Leeds, Leeds, UK
[3] Alpha Petroleum, Guildford, UK

The Cheviot field is a redevelopment of the Emerald field which was discovered in 1975 and initially developed in the mid-1990's. However, as a result of extensive, early water breakthrough, the Emerald field was abandoned when only 8% of the original oil in place had been produced. Water breakthrough was ascribed to the presence of a fracture system in the underlying basement and characterization of this was deemed crucial to the redevelopment plans. The field sits in on the western margin of the North Viking Graben. The main reservoir is the Middle Jurassic Emerald Sandstone which has a thickness of around 15m. The Emerald Sandstone variously overlies Lower Jurassic, Old Red Sandstone and, the main focus of this study, metamorphic basement of probable Dalradian affinity. The metamorphic basement subcrops the central part of the field and this is where most problems were encountered with early water breakthrough into producer wells.

Cored basement and Old Red Sandstone wells were described with fracture types ranging from fully cemented with phases such as calcite, dolomite and pyrite, through partially cemented fractures retaining some porosity, to uncemented fractures. Small, sand-filled fractures occur within a few feet of the top basement unconformity. These, along with the part-cemented and uncemented fractures, comprise the subset of fractures that are likely to be open and contribute to flow and storage in the subsurface.

The basement lithologies comprise biotite schist, metabasite, quartzo-feldspathic gneiss, pegmatite, calc-schist and marble. Pegmatites cross-cut the foliation at low angles and show oil-stained fractures. The dominant foliation dips moderately (20-40°) and is intermittently deformed by centimetre to metre scale asymmetric folds with a down-dip vergence. These and asymmetric feldspar porphyroclasts indicate a top-down-dip sense of shear, possibly associated with late-stage, postorogenic extensional collapse. Early steep-dipping fractures and foliation parallel brittle structures developed at this stage. Subsequent fracturing is attributed to Triassic and Jurassic extension and the basement was exposed prior to deposition of the Emerald Sandstone.

Potentially open fractures show an increase in density to about twice that of the 'background' level within 30-50m of a fault. The dominant control exerted by fractures in fault damage zones is indicated by tracer tests with rapid response times seen in wells along the mapped fault trends. Potentially open fractures, many showing oil staining, occur in a basement core which extends to c.60m below the unconformity. There is no oil staining, no host-rock alteration and far fewer partcemented fractures in an off-structure basement core which lies c.215m below the unconformity. Although a large range, the available data suggest that the effective fracture system extends <200m below the top basement unconformity.

Fracture densities in core can be used to calculate the average spacing between fractures and this, in turn is used to determine fracture porosity and permeability.The apertures of potentially open fractures measured in core range between c.0.1 and 20mm. Most fractures have apertures of <1mm. The apertures appear to follow a fractal scaling relationship. Deformation in the Emerald Sandstone itself is minimal. There are few clusters and individual occurrences of deformation bands and cemented fractures in the Emerald Sandstone but these are not thought to have a significant effect on fluid flow through the reservoir. The basement fracture model consists of different models for the metamorphic basement and Old Red Sandstone. The metamorphic basement and Old Red Sandstone models consisted of two components, a background level of fracturing and a fault related fracture component due to enhanced levels of fracturing in fault damage zone.

The background fracture density was mapped using the density of potentially open (part-cemented and uncemented) fractures as measured in core from the Cheviot wells. Permeability was derived using the fracture density/spacing data and the distribution of fracture apertures measured in core. Large apertures were not included as these were considered to be rare and unlikely to be widely distributed in the fractured basement. Fracture permeability was also degraded by a factor to account for partial cementation and roughness of the fractures. The maximum permeability is parallel to the dominant fracture trend.

The fault related permeability component was superimposed on this background permeability. Permeabilities were determined for the fault zones on the basis of the increased fracture density and then upscaled. The upscaling process combined background permeability and fault zone permeability into an individual grid cell. The basis for upscaling was the relative widths of fault zone and background in the cell. As fault throw increases so does the fault zone width and so it makes a greater contribution to the cell permeability.

NOTES:

Understanding the dynamic behaviour of the Lancaster Field, West of Shetland

Antony Harris[1], Lindsay Kaye[2], Dan Bonter[3], Bob Foulser[4]
[1]*Axis Well Technology, 24 Abercrombie Court, Westhill, Aberdeenshire, AB32 6FE*
[2]*Lindsay Kaye Ltd, Sawpits, Froggetts Lane, Walliswood, Dorking, Surrey, RH5 5RJ*
[3] *Hurricane Energy plc, The Wharf, Abbey Mill Business Park, Lower Eashing, Godalming, Surrey, GU7 2QN*
[4] *Decision Management Ltd, 9, Abbey Street, Cerne Abbas, Dorset, DT2 7JQ*

Lancaster is a large (486 MMboe 2C) fractured basement field, located West of Shetland in the UKCS. It is classified as a Type 1 naturally fractured reservoir (Nelson, 2001), meaning hydrocarbon potential is provided entirely by the fracture network, which comprises large discrete joints and an extended network of connected microfractures. The production potential of the Lancaster Field has been appraised through the testing of two 1km long horizontal production wells (205/21a-6 and -7Z), which both demonstrated high deliverability with production rates of 9,800 and 15,400 STB/d respectively. High quality pressure data was obtained during the tests, both downhole and on the seabed. The downhole tidal response proved the existence of a compressible component to the reservoir system, which can only be provided by the network of non-discrete microfractures, whilst the measured gauge data demonstrated a dual porosity response, showing that these microfractures contribute about two thirds of the storage available and are well connected to the system of joints.

A distinctive pressure response was observed in both horizontal wells, which cannot currently be replicated using a single, analytical model with standard pressure transient analysis software. In particular, a pseudo dual-storage response was observed in the early time data, where the major joint system contributes to the wellbore storage effects and is believed to be a characteristic signature of wells in this type of reservoir. Whilst this is unusual for 'standard' wells, it provides a framework for interpretation of further fractured basement wells along the Rona Ridge. The integration of the geological understanding and the pressure response through creative use of pressure transient analysis software has allowed a consistent interpretation of the dynamic behaviour of the wells for the duration of the tests and verified the pre-drill geological model. As the project moves forward towards first oil, the robust understanding gathered from the analysis of the well tests is likely to be critical in building a fully integrated tool for reservoir performance monitoring.

NOTES:

Basement Fracture Characterisation on the Liverpool Land Basement High, Central East Greenland

Graham Banks[1], Pierpaolo Guarnieri[1], Dennis K. Bird[2], Sara Salehi[1], and Stefan Bernstein[1]
[1] *Geological Survey of Denmark and Greenland, Copenhagen, Denmark*
[2] *Stanford University, California, USA*

Crystalline basement fracture networks are known to host economically viable mineral deposits, e.g. orogenic gold, non-magmatic copper and petroleum Reserves (fractured, basement reservoirs in >30 countries). Fractured basement reservoir has gained renewed interest after recent, giant, oil discoveries in North Atlantic region basement highs, e.g. Johan Sverdrup, Lancaster and Halifax. Characterising and predicting fractured basement reservoirs/mineralisation requires integrated 3D models spanning gravity survey- to core plug-scales. This has some challenges. Basement reservoirs are lithologically and structurally variable and complex, and their hydrodynamic fracture networks formed by one or more of: cooling, tectonism, weathering, chemical alteration, unroofing processes. Fieldwork-scale analysis of fracture generations are often under-represented. The nearest outcrops to offshore basement discoveries may be in distant tectonic blocks, so may not be appropriate stress history analogues, etc. Liverpool Land Basement High presents an ideal natural lab to discern basement fracture network evolutionary processes in 3D. This exposed 'basement' to the Jameson Land Basin, comprising Mesoproterozoic-Palaeozoic igneous and metamorphic terranes, is an extensively outcropping (2500km2) Jameson Land Basin rift shoulder. This basin-basement adjacency could enable direct comparison of some fracture system characteristics, at least of fracture network properties caused during their common unroofing and stress field history.

Reconnaissance sattelite imagery and field-based lithological and structural analysis on Liverpool Land Basement High in 2018 will range through: seismicscale lineament analysis; basin boundary related faulting; decametre-scale fracture system connectivity; metre-scale fracture fill/porosity; potential fault sealing and (re)opening mechanisms; relative timing of fluid-rock reactions. All at a span of scales not possible in covered basement highs.

NOTES:

A Review of the Yemen Fractured Basement Play

David M Hall
Sul Geology (Independent Consultant)

Yemen is well known as a successful example of the Precambrian fractured basement play which, to-date, has produced between 250 to 300 Mbo. Several fields, of which Kharir and Sunah are the largest, are located in the Masilah Basin, and one fields, Habban, is located in the central part of the Marib-Shabwah Basin.

Both basins were created by Upper Jurassic to Lower Cretaceous rifting and are characterised by complex fault geometries that were inherited in large part from from precambrian structural lineaments. The presence of multiple intersecting faults has been a key factor in determining the success of the Yemen basement play. Another important factor is the probably the reactivation and dilation of faults that occurred during the late Cretaceous and Tertiary. It can be inferred that this enhanced reservoir fracture porosity and permeability and also improved the efficiency of oil migration from the adjacent Upper Jurassic Madbi Formation source rock.

A frequent characteristic of the producing fields plus other discoveries in Yemen is that the hydrocarbon columns are greater than mapped top reservoir structural closure with no clearly defined field-wide oil-water contact. It is suggested that the term “fracture trap” (or frac trap) is a more appropriate classification for these types of traps. Fracture traps are defined as trap geometries that are controlled primarily by the extent and connectivity of the fracture network rather than local top-seal closure. It follows that application of this concept increases the recognition of exploration opportunities.

Operational experience emphasises the value of drilling penetration rate, fluid losses and gas-log ratios for the initial identification of fractured pay intervals prior to further characterisation by image and other wireline logs. The probability of by-passed pay in basement penetrations is higher than average as even slightly over-balanced mud-weights can mask these hydrocarbon indicators and also impair DST flow performance.

Basement production from the Yemen Fields is dominated by a relatively small proportion of the overall fracture network in which the larger proportion is characterised by lower permeability hydrocarbon storage fractures. A good illustration of the relative contribution of different fracture sets is provided by fluid flow and production data from the Kharir Field.

The uncertainty in predicting the location of commercially producing fracture zones is particularly significant during the exploration and early appraisal stage. To mitigate this it is therefore important to drill wells with lateral off-set trajectories that are long enough to maximise the chance of success.

About 350 exploration / appraisal wells have been drilled to the basement in Yemen, of which only 10%, mostly clustered close to existing production, have a lateral off-set greater than 200m. This emphasises the under-explored status of the play.

** Yemen Geoscience director and exploration manager for TOTAL from 2013 to 2018. The presentation will be given as an independent consultant following retirement from TOTAL in September 2018.*

NOTES:

Session Five: Fractured Reservoirs Data Integration

KEYNOTE: Characterising Fractured Reservoirs: insight from the movie "Life is Beautiful" ("La Vita e' Bella")

Raffaele Di Cuia
Delta Energy Ltd., Central Court, 25 Southampton Buildings, London WC2A 1AL, UK

Life Is Beautiful (Italian: La vita è bella) is a 1997 Italian comedy-drama film directed by and starring Roberto Benigni. Benigni plays Guido Orefice, a Jewish Italian book shop owner, who employs his fertile imagination to shield his son from the horrors of internment in a Nazi concentration camp.

The film was a critical and financial success, despite criticisms of using the subject matter for comedic purposes. It won the Grand Prix at the 1998 Cannes Film Festival, nine David di Donatello Awards, including Best Film, in Italy, and three Academy Awards, including Best Actor for Benigni.

The core of the story behind the movie is that the reality sometimes can be different from the story we build or we hear from others. The movie is presumably intended as a tribute to the powers of imagination, innocence, and love in the most harrowing of circumstances (T. Dawson, 2002). The movie is also about rescuing whatever is good and hopeful from the wreckage of dreams and about hope for the future.

The characterisation of fractured reservoirs has several similarities with the main messages of the movie.
The characterization of fractured reservoirs is a complex task because involves the use of different dataset and a mindset able to approach issues at different scale and build concepts and models using missing information.

Characterizing fractured reservoirs also means to build a reasonable static picture of the fault and fracture network at different scales that is validated by dynamic data and it is able to predict the movement of fluids within the reservoir.

The availability of new data often changes the picture we built of the fault and fracture network and shows how reality can be quite different from models that were initially proposed and this pushes to develop new concepts and new approaches to integrate the new data with the existing dataset and to be ready "to read the new reality with different eyes".

Using examples from subsurface and outcrop analogues I will try to highlighting some warnings about uncertainties related to the characterisation of Fractured Reservoirs

NOTES:

Fracture aperture in reservoir rocks: examples from the Shetland Chalk in the Gullfaks Field

Ole Petter Wennberg[1], Marcel Naumann[1], Sima Jounoud[1], Alexander Rozhko[2], Brita Graham Wall[3], Ellen Sæther[1]
[1] *Equinor Bergen, Norway.*
[2] *Equinor Stavanger, Norway*
[3] *Equinor Oslo, Noerway*

'Aperture' is a key parameter for the estimation of fracture permeability and fracture porosity. However, it is generally a challenge to quantify fracture aperture from core because long fractures cause the core to fall apart, core recovery is very poor in intensely fractured intervals and the stress release when the core is taken to the surface will affect the observed apertures.

In this study we have used core samples of chalk from the Cretaceous Shetland Group in the Gullfaks Field which contain preserved natural open fractures. Core observation, thin-section and CT data show that the open tensile fractures are partly filled with calcite cement. The precipitated calcite represents cement bridges between the fracture walls and/or lining on the fracture surfaces. The fracture density is controlled by matrix porosity and the occurrence and shape of the tensile fractures are often influenced heterogeneities in the host rock like bioturbations. Fractures are observed to terminate or reduce their mechanical aperture against burrows (Thallassinoides). The fractures may also follow the rim of burrows or connect between burrows.

Combined rock mechanical and flow tests were conducted on a preserved, partly calcite-cemented natural fracture at in-situ stress. The pressure was changed within the operational window of the reservoir i.e. the expected stress states during water injection and depletion. Fracture aperture changes were detected with a pair of specialized clip-on extensometers which measure the deformation normal and parallel to the fracture. The mechanical aperture was estimated by use of micro CT show a distribution of values skewed towards higher values (Figure 1a and b). The average is 183 µm and the standard deviation 24 µm at surface conditions. Measuring aperture changes during triaxial stress testing indicate that the average mechanical aperture at initial reservoir conditions is 161 µm. Modelling suggest that mechanical apertures approach a normal distribution at in-situ stress conditions (Figure 1c).

The flow tests show that the hydraulic aperture is significantly smaller, almost one order of magnitude, than the mean mechanical aperture, which is explained by fracture rugosity and presence of calcite cement bridges within the fracture. Hydraulic aperture and single-phase fluid flow was dependent on the effective normal stress (Figure 1b). The ratio between hydraulic and mechanical aperture was constant during stress changes within the operational window of the reservoir.

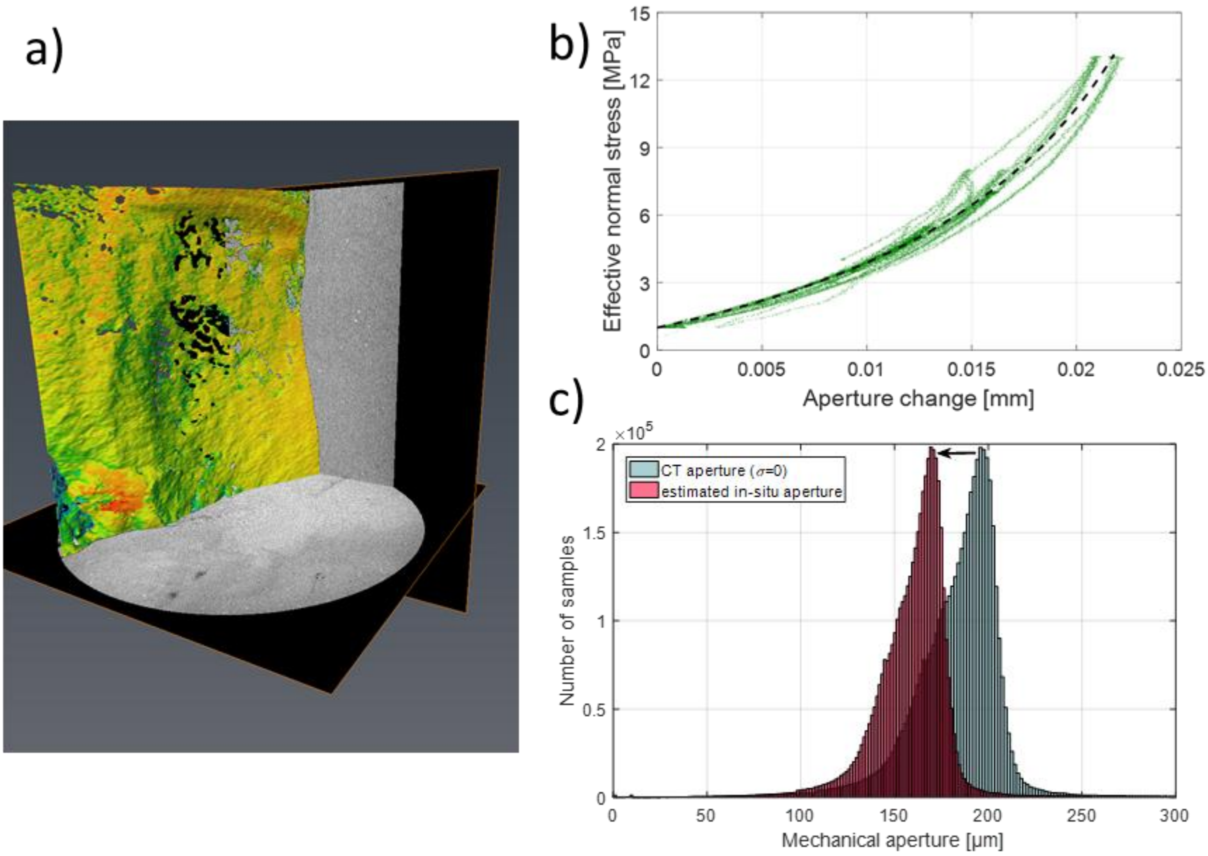


Figure 1. A natural fracture in a sample with 38mm diameter. a) CT image showing variation in mechanical aperture (max in red = 0.3 mm). b) Aperture change as function of effective normal stress. c) Distribution of aperture before and after stress correction.

NOTES:

Fractured reservoirs of Oman: Geological overview, challenges and opportunities for the development of hydrocarbon resources

Loïc Bazalgette[1], Shadia al Farsi[1], Salim al Shuaili[1], Said al Balushi[1], Said al Rahbi[1], Siham al Falahi[1] and Peter Swaby[2]
[1]*Petroleum Development Oman, P.O Box 81, P.C 100, Muscat, Sultanate of Oman*
[2]*Shell Projects and Technology*

Naturally fractured reservoirs have been developed in the Sultanate of Oman for nearly sixty years. They are mainly located in the northern region of the country where they are associated with Mesozoic carbonate formations and where they provide the largest part of the current oil production. To a much lesser extent, fractured reservoirs also exist in South Oman where they are more specifically associated with a local intra-salt formation.

Fractured reservoirs of Oman can be sorted into different types. The typology must take into account the petrology of the reservoir, its structural evolution during the regional tectonic history as well as the nature and properties of the hydrocarbon content. Different combinations of all these parameters lead to the occurrence of contrasted associations between matrix, fractures and fluid properties which influence drastically the dynamic behaviour. This results in the implementation of various production strategies due to very specific development challenges and opportunities.

This paper will present a selection of well-documented naturally fractured reservoirs examples in the Sultanate of Oman. Reservoir geology, fracture scales and fracture typologies will be discussed for each example, as well as the main characteristics in terms of fluid and dynamic behaviour. Based on this selection, a classification will be proposed, together with a dedicated list of development challenges and opportunities.

NOTES:

North Kuwait Carbonate Fields: Calibrating fracture model permeability and porosity using core and pressure transient analysis data

P. Richard[1], S. Lamine[1], C. Pattnaik[2], V. Kidambi[2], R. Narhari[2], P. Swaby[3], E. Van der Steen[4] and Q. Dashti[2]
[1]Shell Global Solutions International BV
[2] Kuwait Oil Company
[3]Swaby Software Limited
4Shell Kuwait Exploration and Production BV

Introduction

The North Kuwait Carbonate reservoirs (NKCR) are being developed by KOC (Kuwait Oil Company). The development of the NKCR offers challenges such as lateral variations in reservoir quality, tight to very tight reservoirs and natural fracturing to a varying degree spatially. The presence of open and connected fractures is one of the key elements to achieve a successful development. Also, the presence of fracture corridors increases the risk associated with drilling. To reduce the uncertainty inherent to the sub-surface natural fracture network, an invaluable set of core and well test data have been acquired. These have been the foundation of numerous fracture modelling studies (Richard et al, SPE 188135), supporting both appraisal and development strategies of the fields. A solid understanding of the fracture network has been developed based on a structural evolution model and detailed fracture characterization using static BHI (bore hole images) and core data as well as dynamic data. A wide spectrum of scales of discrete fracture network (DFN) models have been built to help business decisions.
This paper concentrates on the specific aspect of the calibration of the upscaled porosity and permeability properties from the DFN's.

DFN object fracture porosity calibration

Overall, the highest values of fracture porosities have been observed along wells located within inverted ridges (red square on Figure 1). However, some wells in the inverted ridges have also some lower values of fracture porosity. This can be attributed to the heterogeneous nature of the fracture networks in the sub-surface. The core values have been used to constrain the DFN fracture porosity. To obtain a match between the core and DFN model porosity, aperture of 1 and 5 mm have been assigned to the fracture sets to honour the observed fracture anisotropy along the long axis of the inverted ridges.

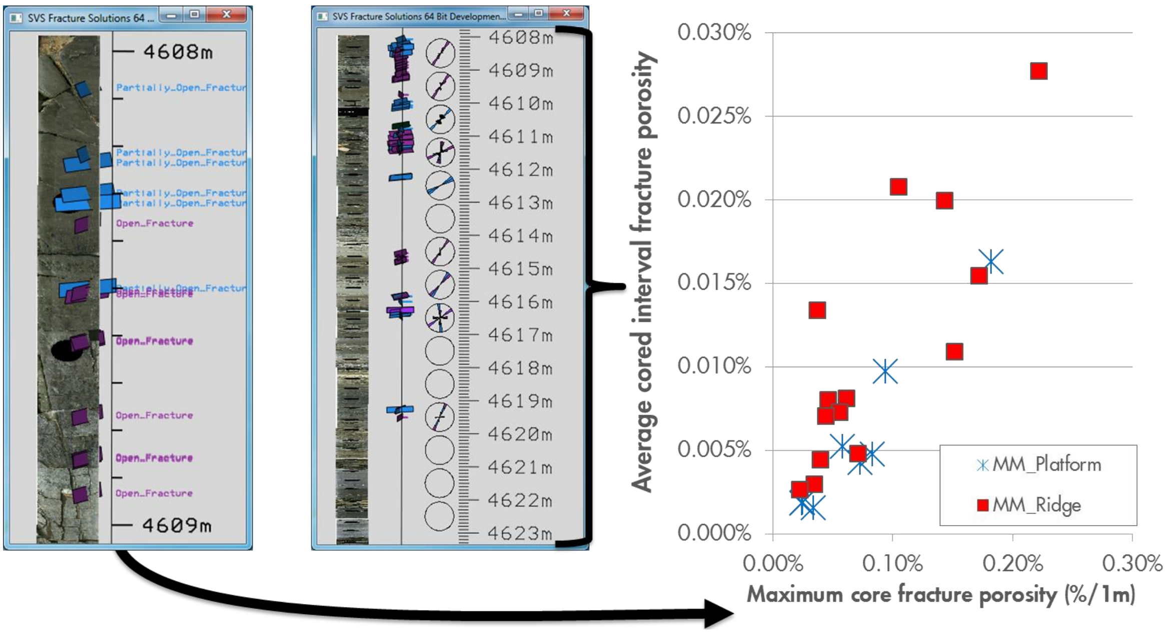


Figure 1: Fracture porosity observed on cored interval.

DFN object fracture permeability calibration

The key calibration for the DFN fracture permeability is the permeability estimated from the PTA (Pressure transient Analysis) data. The effective fracture permeability, constrained from PTA analysis, ranges between 50 and 200 md (Lamine et al, 2017, SPE 188835).

In order to pre-condition the static model to the PTA data, a series of models has been considered using a stepped approach. A 6 by 6 voxel sector has been carved out from the full field 3D grid with matrix porosity and permeability properties. The sector is approximately 1.2 km x 1.2 km. Fracture properties have also been computed from the DFN model and are the subject for calibration to match the data from the PTA. All models have been meshed with a 2D triangulation, using fine resolution around the well becoming coarser away from the well (see bottom left insert on Figure 2). The simplest model (A) is a matrix only model without fault. It only uses the matrix properties. Faults have been gradually added to the models (B and C). The faults are conductive and have been given a high transmissivity. The product of the permeability times the aperture is in the order of 1000 D.m. The simulated pressure derivative responses for these three first scenarios indicate that the model kh is underestimating the observed data around the well by more than 100 folds. We then added fractures into the models by mean of fracture properties or meshed representation of sector DFN models. In order to get a match, the well needs to be intersected by a fracture corridor. These can be achieved by simply multiplying the matrix permeability by 100, adding a corridor object to a coarse DFN fracture mesh or using the upscaled permeability from the full field DFN. It illustrates that the full field DFN is a potential valid representation of the sub-surface fracture network permeability and can be considered as input for the field development.

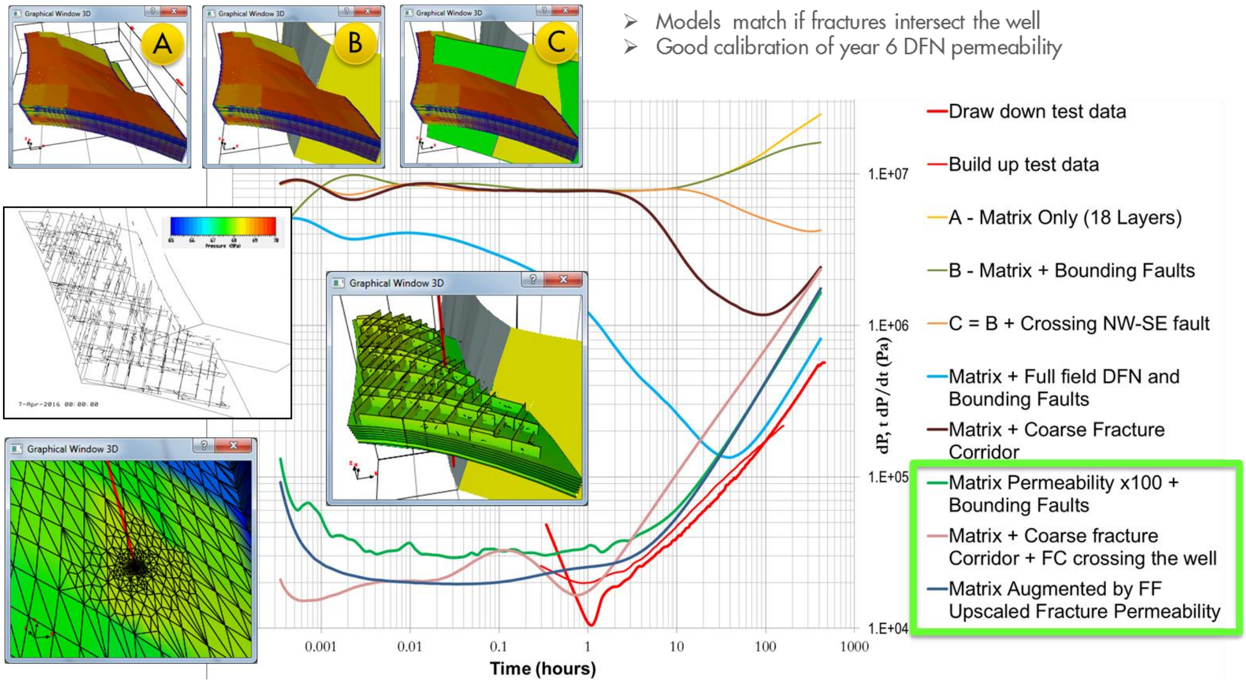


Figure 2: Example of detailed DFN calibration with PTA data.

Conclusions

These examples illustrate how core and PTA data can be used to calibrate DFN fracture object porosity and permeability. However, even with the use of this invaluable dataset of core and PTA, there is still a high uncertainty in the distribution and range of DFN porosity and permeability. These will be captured in the range of scenarios carried in the dynamic simulation for the history matching and forecast work.

NOTES:

Reservoir modelling challenges in naturally fractured tight carbonate reservoirs from the Potwar Basin, northern Pakistan

Ali, S[1^]., Raja, Z.A[1]., Roy, S.A[1]., Afzal, I[1]., Zafar, Z.A[1]., Kumar, S[1]. and Burley, S.D[1&2].
[1]*Ocean Pakistan Ltd, PTET House, G-10/4, Islamabad Basin*
[2]*Dynamics Research Group, University of Keele Department of Geology and Earth Sciences, Keele, UK.*

Abstract
The Potwar Basin in the foothills of the Himalayas, underlain by Cambrian salt which provides a regional decollement surface on which tens of kilometres of crustal shortening has taken place. The resulting compressional folds and thrusted anticlines in the Mesozoic and Tertiary cover sediments host important oil and gas fields (Figure 1). Many of the fields in this area have reservoirs in the Palaeocene to Eocene shelfal carbonates deposited on the northern leading edge of the Indian plate which are characterised by very low matrix porosity (~2%) and permeability (<10mD) systems. Hydrocarbon production is only possible from complex fracture systems associated with the large scale thrusts and folding. We are interested in fracture modelling in such tight carbonate reservoirs to identify areas of by-passed oil and isolated fracture compartments for infill well planning in mature fields.

We present as an example of the Potwar Basin fractured carbonate fields a case study of the Dhurnal Field, a triangle zone pop-up structure with a relatively simple thrusted anticlinal geometry (Figure 2). Seven wells have been drilled in the field with oil production almost exclusively from the extensive fracture network developed in stacked carbonate reservoirs of Permian to the Eocene age. Exposures of the reservoir sequences outcrop to the south of the field where steep thrusts bring the Palaeocene and Eocene limestones to surface and enable the association of fractures to thrusts and faults to be examined and used to relate fracture distributions to the 3D seismic fault-likelihood attribute in the subsurface. All available vintage dipmeter and FMS data has been rescued from hardcopy to digital format to make it usable for analysis and calibration of discrete fracture network (DFN) models.

The main technical challenges in modelling fractures in these fields are (i) building geocellular models with the correct geometry and multiple z values (ii) defining the distribution of fractures in relation to structure, faulting and lithology (iii) distinguishing open from closed fracture sets and (iv) up-scaling to capture realistic porosity and permeability properties to the dynamic simulator. Geological analysis of fractures at outcrop and in core and image logs gave an understanding of change in fracture orientation in each field compartment, fracture density variation by lithology, fracture relationship to faults and the relationship of fractures with losses recorded during drilling. Sets of discrete fracture networks were developed combining the well with seismic attribute data. Fracture modelling parameters including intensity, dip and azimuth were populated from well and seismic data using prior to input to DFN modelling using industry commercial modelling software (Figures 3 & 4). Sensitivities on fracture length, orientation, density and connectivity were investigated to test their impact on history matching in a dynamic simulator.

Computational limitations in commercial software in upscaling these large DFN models need to address dual porosity and permeability model properties and simulation times. Cloud-based simulations using optimised CPU clusters is a significant development for handling very large DFN models.

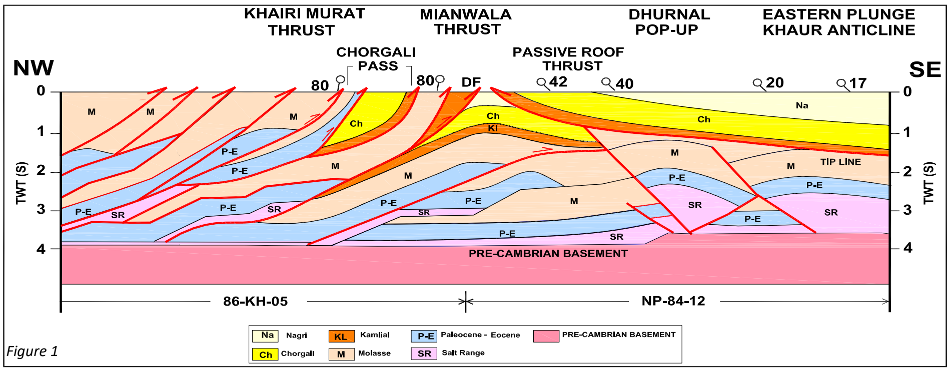


Figure 1

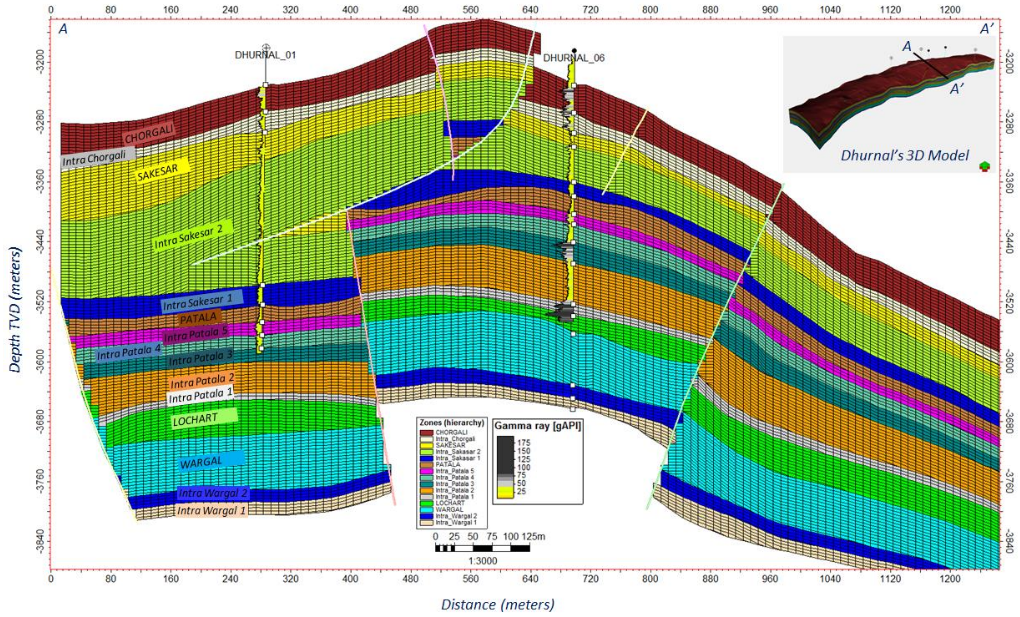


Figure 2: AA' X-section from 3D geological model of thrust fault passing through Dhurnal_01 and Dhurnal_02 wells

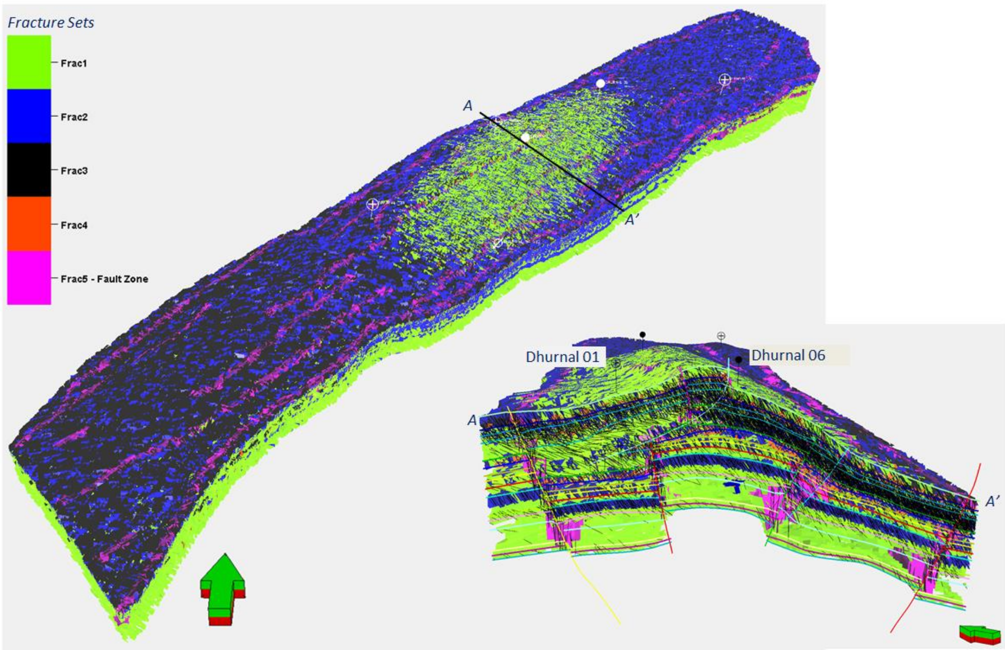


Figure 3: 3D View of Fracture Model

Figure 4: AA' X-section from 3D fracture model

NOTES:

An Integrated approach to develop a prospective sub-thrust model in the Sub-Andes, Bolivia, and comparison to analogues in Iraq and Italy

Tina Lohr[1], Jon Gutmanis[2]
[1] *ERCE*
[2] *independent consultant on behalf of Echo Energy and Pluspetrol*

We have taken a multi-disciplinary approach and integrate geological data, fracture and pore-pressure data, and structural modelling in order to understand the exploration history, and to investigate further the prospectivity at depth of an anticlinal structure.

The area of study is located in southern Bolivia, within the Sub-Andean fold and thrust belt, a highly prospective area for gas. The belt is characterised by elongated anticlines that strike NNE-SSW forming several continuous parallel ranges. The main detachment level is in Silurian Kirusillas shale, which is an efficient decollement level at depth, along which the fold and thrust belt propagates from west to east. Important intermediate detachment levels in Devonian shales generate lift-off structures and decoupling of the lower and upper structural levels.

Hydrocarbons are found in the tight sandstone layers of the Huamampampa, Icla and Santa Rosa formations. All are of Early Devonian age, and have low matrix porosity and permeability. Fracture enhancement is required for productivity. The Huamampampa formation is the main reservoir rock in all the deep gas fields in the Sub-Andes in southern Bolivia and northern Argentina.

Seven wells have been drilled into the surface anticline, evident in the area of study, but only a small gas accumulation has been encountered in the Huamampampa-Icla formations. Reservoir rocks were penetrated unexpectedly shallow, and are less overpressured than anticipated.

We have constructed several cross-sections tied to surface geology and well data. Through data integration and kinematic modelling we have developed a model that explains the current well results and proposes a deeper structure beneath the currently drilled anticline. This model suggests a large imbricated sub-thrust structure at depth greater than four kilometres, that involves Upper Silurian to Lower Devonian rocks which are detached via a roof thrust within the overlaying Los Monos shale.

The lack of adequate seismic data is a major limitation in defining the sub-thrust structure at depth. However, the presence of this structure is reasonable and consistent with the structural understanding of the region. There is an active petroleum system at present day, and several producing gas fields nearby where the reservoir rocks are at similar depths.

The development of naturally fractured reservoir is, of course, not limited to the Sub-Andean fold and thrust belt. We draw on our extensive experience with fractured reservoirs to compare the fractured sandstone reservoir in the Sub-Andes with other examples of fractured reservoirs from Kurdistan and Italy.

NOTES:

Characterization of fractured networks in geothermal reservoirs: from field outcrops to laboratory measurements

Catalina Sanchez-Roa[1], Thomas Mitchell[1], Giulia Magnarini[1], Lucy Cotton[2], Jon Gutmanis[2], John Browning[1], Philip Meredith[1], Adrian Jones[1], Eric Oelkers[1], Lydia Pridham[1] and Phoebe Chappell[1]
[1]*University College London, Earth Sciences, London, United Kingdom*
[2]*GeoScience Limited, Falmouth, Cornwall.*

Fault zones and their associated fracture networks control the permeability of the subsurface. Fault and damage zones in the crust are areas of high stress, where mechanical and chemical processes provoke the development of particular types of rock (fault rocks). Fault rock properties are often well differentiated from the properties of the original wall rock including cohesion, fabric, grain size, mineralogy and, as a consequence, a well differentiated permeability. Active faulting allows interconnected cracks to act as fluid conduits on a temporary timescale. However, fluid-rock interactions and changing physico-chemical conditions of the system lead to the precipitation of new minerals in the fractures, which can be responsible for a significant decrease in permeability (or sealing effect) in mature or fossilised faults. The chemistry, mineral paragenesis and microstructures recorded in fractured rocks contain valuable information about the processes that have taken place as well as revealing important characteristics about the current and future state of the fractured system, considering fluid-rock interaction, mechanical stability and permeability. The study of fracture networks is fundamental to the successful exploitation of rock reservoirs for several commercial uses as is the case of the oil and gas, waste storage and geothermal industries. In the UK, Cornwall is one of the areas with highest geothermal gradient due to the ongoing radioactive decay of its granitic intrusions, making the area a potential candidate for the production of geothermal energy. In this project, we aim to characterize the fracture networks and rock properties of potential reservoirs for geothermal energy generation in Cornwall, UK, using a combination of laboratory measurements and georeferenced spatial datasets acquired by an unmanned aerial vehicle (UAV).

Two fault zone outcrops in the Cornwall area were mapped using UAV-acquired aerial photography. The images acquired in Rinsey Cove and Perranporth Beach were used to construct photogrammetric and digital elevation models in order to identify structural orientation and quantification of vain and fracture systems. The results of the structural analysis will then be used as a basis for experimental tests, through which we aim to determine rock strength, permeability and anisotropy of the reservoir rock, as well as their response to hydraulic fracturing, using a new true triaxial loading system. The true triaxial loading apparatus in the Rock and Ice Physics Laboratory at University College London is equipped with a confining pressure vessel and six axis pore-fluid pressure system that can pressurise samples to reservoir conditions and permits permeability measurements in three orthogonal directions. Three pairs of servo-controlled hydraulic rams provide the loading, whilst loading platens interposed between the rams and the sample faces provide the contact surfaces and distribute the pore fluid. Measurements will be carried out on Cornish granite from the Carmenellis formation, which will be deformed in three orthogonal directions with independently controlled stress paths where: $\sigma 1 > \sigma 2 > \sigma 3$. The experiments will measure strain, acoustic emissions and changes in permeability as a function of polyaxial stresses to identify the opening of pre-existing cracks and the formation of new cracks. True triaxial testing permits simulation of the natural differential stress conditions found within the Earth's crust, thus providing reliable data of fracture propagation, healing and mechanical stability, which is essential in order to assess fluid flow paths in the crust. The comparison between naturally and experimentally fractured reservoirs can provide a strong basis to validate and extrapolate laboratory results to natural settings, which can significantly contribute to the design and optimization of geothermal reservoirs.

NOTES:

"An application to field development of permeability conduits characterization and distribution using geological scenario calibrated with pressure transient analysis data - A Brazilian pre-Salt lacustrine carbonate field example"

R. Micheli Clavier, P. Richard, S. Lamine, A. Barnett, L. Erriah, D. de Verteuil; M. Bolton, T. Whatling et al.
Shell E&P

The Pre-Salt successions in the Santos Basin host some of the largest discoveries in the last decade. The mainly lacustrine carbonate reservoirs show excellent matrix properties reflected in very high well productivity. Locally, matrix porosity is further enhanced by fracturing and karstification. The subjected field complex comprises 3 tilted fault blocks, with bounding faults oriented NW-SE. The subjected methodology focused on the Western accumulation.

The whole structure is an extensional dominated rift system influenced by the geometry of pre-existing structural framework, where main faults show more significant extensional component. The field has a peculiar tight and high relief structural configuration within the Rift and Sag sequences; while there is an abundance of faults trending NW-SE, some NNW- to NNE-trends are also found as wells as minor evidences of mild positive structural inversion.

The studied area has been interpreted as a transtensional structure developed into the extensional dominated rift system. A series of en-echelon faults have been interpreted as kinematic indicator of dextral or right lateral displacement. Lateral displacement has led to complex fault geometries with local transtension and transpressional deformation generating complex 3D fault and fracture networks. Additionally, the fault and fractures network have been exposed to combined action of leaching from deep seated fluid and superficial karstification. According to the well data and the developed geological model, this occurrence is preferentially happening along narrow and elongated structures; often associated with anomalously thick occurrences of high quality depositional facies.

Available well data (well losses, core and image log data) have been analyzed showing evidence of fracturing and karstification, as well giving indication of amount of fracturing. Two families of fractures were identifiable in cores: a set of syn-deposition solution-enhanced, irregular fractures and another made by planar tectonic fractures with little evidence of dissolution. Many of the fractures identified with some crestal wells are potentially associated with early deformation syn-deposition. Tectonic fractures appear to be proportional to vicinity of faults. The impact of karstification intimately relates and enhances the effects of the fractures, although is unclear whether the dissolution is locally focused around faults and fractures or more widespread in the pore system.

For the purpose of this study no a priori differentiation is made between the fractures' origin. Karstification as such, it is not as well explicitly modelled as it is here accounted for by either pervasive fracturing and/or enhanced matrix properties. The resulting fault and fracture network, locally enhanced by karstification is heterogenous, with several orders of magnitude of fracture permeability variation. This complex permeable system and its associated uncertainty have been addressed by an in-house study; subsequently implemented to perform production forecast sensitivities and development scenarios.
Conceptual, simplified fault and fracture network models constrained with dynamic data have been required to aim reducing the range of uncertainty of the plausible solutions. The geological components chosen to represent and simplify the actual fault and fracture networks (and possibly karstification) are the following:

- Single/Multiple Corridors – Fault and Fracture corridors;
- Explicit DFN Models – Pervasive Discrete Fracture Network;
- Static Properties - Matrix or enhanced matrix only.

The screening and calibration of simple or combined geological components with the dynamic well data generated a range of fracture models and properties which were then simulated in DPDP. Such DPDP suite of models, combined with structural end-members and geological scenarios are instrumental to explore the wide range of uncertainty associated with the focused accumulation, optimizing its on-going appraisal and development. At this stage of the development, without continuous production and with a substantial scarcity of dynamic data, a large number of DPDP sensitivity cases are necessary to quantify the impact and uncertainty around the potential fracture systems. The DPDP modelling has been fully utilized in production forecasts, development scenario, well placement.

NOTES:

Old oil discoveries in tight fractured carbonates with limited fracture information: how to build a Discrete Fracture Network Model to help the appraisal strategy

Raffaele Di Cuia[1] & Paolo Pace[2]
[1]Delta Energy Ltd., Central Court, 25 Southampton Buildings, London WC2A 1AL, UK
[2]G.E. Plan Consulting, Petroleum Geosciences, Via Ariosto 58, 44121 – Ferrara, Italy

The standard tools (image logs, multi azimuth acoustic log, high resolution 3D seismic, multi-azimuth downhole seismic) to detect the presence and to characterise fracture networks in borehole drilled in 70's and 80's were not available. Therefore, the characterisation of fractured reservoirs was very complex and at the same time very limited and sometime lead to the poor understanding of the reservoir behaviours and the underestimation of the discovery potentials.

Nowadays, to appraise or re-develop old discoveries made in fracture tight reservoirs it is necessary to deal with the lack of information regarding the fracture network characteristics and to use alternative approaches.

This study shows the examples of two oil discoveries in tight fractured carbonate reservoirs made in the early 70's and early 80's respectively and not developed. These discoveries have been re-evaluated and need to be correctly characterised before the new development drilling phase take place.

The two discoveries lie in a complex tectonic setting and despite similar present day petrophysical properties have reservoir age and facies different. The two structures are part of a larger arcuate structure (more than 100Km wide) and they lie on the lateral ramp of the structural arc. This fact adds more complexity in term of orientation of the present day stress field and orientation of critically stressed fractures.

The dataset is composed of 5 wells with cores and vintage well-logs, 2D seismic lines, drilling and test data. Regional geological information from wells in the surrounding and from regional seismic is also available together with data from present day seismicity.

In this framework it was decided to use an integrated approach to extract the maximum amount of fracture information from the available data and to use a multiscale and multi-scenario approach to produce realistic drivers for the discrete fracture network modelling.

Restoration and forward modelling were also used to produce a several 3D strain distribution scenarios used to drive the fracture modelling.

The results of the fracture modelling were used to populate a dual porosity, dual permeability reservoir model and to help planning the design of horizontal development wells.

Poster Presentation Abstracts

The Detection, Classification and Impact of Stylolites and Associated Fractures in Carbonate Reservoirs

Alexander Foote
Structural Geologist at Badley Ashton

One of the most common structural features observed in carbonate reservoirs around the world are stylolites and the fractures directly associated to their development. The role of stylolites, often considered as barriers and baffles to flow, can actually be much more complex with certain morphologies contributing to flow within a reservoir as a result of brittle deformation. It is therefore important to detect, identify and classify varying stylolite morphologies within a reservoir to understand their impact on fluid flow. Classification can be done broadly by splitting stylolites into brittle or ductile, describing the degree to which the seam of the stylolite is compromised through shear and tension gashes that commonly affect the plane. Beyond this simple characterisation, accurate measurements of stylolite amplitude, seam thickness and tooth frequency are key to understanding the potential three dimensional morphology and the impact on fluid flow.

Fracturing associated to fractures also needs to be considered carefully in terms of their positioning on the stylolite (within the plane or external to the stylolite on one side or both) and as well as mineralisation that may impact secondary porosity around the stylolite. No straight forward relationship between the intensity of associated fractures and stylolite morphology can be attempted without first realising that these are dictated by the rheological control of the rocks in which they are formed. This means that the impact of stylolites may vary significantly from reservoir to reservoir requiring detailed analysis of their distribution.

Detection methods across scales dictate the accuracy in which the reservoir impact of stylolites can be assessed in terms of stylolite count and morphology. By far the most accurate is direct core observation enabling precise identification and measurement of morphological features including amplitude, tooth frequency, seam thickness and degree of fracturing. Where core is not available, high resolution borehole images can be used to investigate larger stylolites to varying degrees given good image quality, however, stylolite occurrence is significantly underrepresented and morphology is very difficult to ascertain. Log responses from gamma ray can be used but will only detect stylolites with thick seams and can indicate their presence, therefore reducing predictability of fluid flow impact.

High Resolution Mechanical Characterisation of Mudstones: A Comparative Atomic Force Microscopy Study

Samuel P. Graham[1], Mohamed Rouainia[1], Andrew C. Aplin[2], Dr Pablo Cubilas[2]
[1]*School of Engineering, Newcastle University*
[2]*Department of Earth Sciences, Durham University*

The surge in the exploitation of shale gas resources in recent years has required an increased understanding in the geomechanics of these self-sourcing reservoirs. Detailed characterisation of the mechanical properties of conventional hydrocarbon reservoirs by traditional laboratory-based methods is routine, however the difficulty in obtaining good quality core from mudstones leads to reduced resolution in geomechanical models. In recent years, much effort has been expended to apply numerical and laboratory based micromechanical methods to determine material responses, the most prevalent being nanoindentation. Despite its name, nanoindentation can only sample the bulk response of a region a few microns across. Although techniques exist for retrieving individual component responses from such tests exist, determination of the properties of organic components remain difficult, consequently the mechanics of organic components remain poorly constrained. Constraining this value is of particular importance for numerical upscaling models to accurately account for the contribution from this component. Important fracture governing material parameters such as fracture toughness and stress intensity factors can all be expressed as functions of Young's modulus. The ability to better constrain material properties of individual components will allow for better prediction of bulk moduli through numerical homogenization routines, leading to better estimation of these parameters.

Atomic force microscopy (AFM) offers the potential for much improved resolution in mapping mechanical properties and has been widely applied in the assessment of biological materials and polymers. Recent advances in data acquisition rates have led to increased resolution of AFM based mechanical mapping, where it is now possible to obtain resolutions of up to 512x512 measurement points on regions as small as 10μm x 10μm. So far a limited number of studies have applied AFM to the characterisation of organic matter in mudstones, with the results illustrating a more complex mechanical response than that revealed by nanoindentation. Subject to suitable calibration, it has been demonstrated that various high-speed AFM modes can give comparable results for samples with Young's Moduli of c.500kPa. It has also been demonstrated that the calibration standard chosen needs to be comparable to the expected stiffness of the material to be characterised, with deviation between the AFM based value and expected value observed as material property deviates from that of the standard. In order to be applied more widely to mudstone characterisation, the repeatability of AFM based measurements across various high-speed modes (not just the PeakForce™ mode that has been used so far) needs to be demonstrated for Young's moduli on the order of GPa, furthermore, the magnitude of drift in the measured value relative to that of the standard needs be assessed for the graphite standards. This study provides the results of the first systematic evaluation of AFM modes on materials with expected moduli of several GPa.

Subsurface Fracture Flow Evaluation - A Review

M. Johansson
Geode-Energy

Fractures are omnipresent in most geological formations and are a result of brittle rock failure under various states of stress. Fractured reservoirs, which are often characterized by low porosity and high permeability, have a substantially different behaviour and flow pattern than conventional reservoirs. Fractured reservoir classifications are usually based on the matrix contribution to the recoverable reserves, and therefore they can be described as either porous or non- porous. Porous fractured reservoirs are the most common type, with the majority of oil in place being trapped within the matrix and the flow of fluid takes place inside the fracture network.
However, the impact and significance of fractures in the reservoir vary depending whether the fractures enhance fluid flow,or are detrimental to the borehole conditions such as (i) forming a conduit for mud losses, (ii) creating a drilling hazard such as forming ledges, (iii) producing water into a hydrocarbon well, and/or (iv) allowing drilling fluids to leak into a water reservoir, to name only a few. Determining the importance of fracture flow in a reservoir is critical to reservoir management and because of the complexity of any fracture flow evaluation, there needs a holistic approach incorporating and integrating all data from all aspects of acquisition.
There are four main controls to characterising and modelling fractures in the subsurface:

i i) Mechanical and Facies Control
ii ii) Porosity Control
iii iii) Permeability Control
iv iv) Flow Efficiency

Mechanical and Facies Control
The fundamental starting point of any fracture study would be to understand the regional stress regime and to determine the proximity of the borehole to a fault system. During drilling, the primary data source indicating fractures in a reservoir are the drill cuttings, which are often angular and mineralized. The presence of fractures are often associated with mud losses, increased rate on the bit and spikes on the gas shows. These spikes of are often powerful gas surges emitted from the fractures but are short lived, with gas production returning to a nominal base line over time.
One of the enigmas of understanding subsurface fractures is whether they are induced, enhanced or natural. Enhanced and Induced fractures are often indicative of an over pressured well and although they tend to have large apertures, they are considered to have short fracture lengths. The presence and density of natural fractures can be difficult to ascertain from log data as their occurrence in a well are often related to the angle of deviation and orientation of the borehole. In vertical wells with high angle fractures the wells will intersect only a few fractures, whereas in high angle wells, obviously more fractures will be intersected, with the majority of the fractures being perpendicular to the drilling orientation. Therefore assessing fracture density and orientation from log data is often greatly biased by the borehole trajectory and angle of deviation.
The formation lithology is a major mechanical control on fracture attributes. Major fracture swarms can be identified from LWD and Wireline Image logs, as well as from high resolution seismic data. However, the key measurements needed to model fracture flow are aperture, length and connectivity, and all three measurements are difficult to ascertain and are often derived indirectly. Often in the absence of data, fractures are often used in production simulation and history matching to account for the disparity of permeability of log/core date to production data. Even though during facies studies, these high production spikes are actually ‘super-k’ horizons which are facies driven and not caused by fractures. In addition, in carbonates or calcareous sediments, if logging takes place after stimulation, fractures apertures are enlarged due to acidification and therefore accurate fracture characterisation is compromised.

Porosity Input Control
Well log derived porosity measurements techniques derived from conventional reservoirs, cannot be applied to fractured reservoirs. Accurate measurements of fracture porosity is a challenging task, as the volume of fractures is normally smaller than the accuracy of the measurement tools. However attempts have been made to calculate fracture porosity from image data, and this is defined as the percentage of the borehole wall which is represented by the fracture. This porosity is derived from the fracture aperture, trace length, and the borehole coverage from

borehole images. It should be noted that these fracture porosity values apply only to the fracture void space and not with matrix porosity. In practice, where data is not always available fracture characteristics such as porosity can be derived from the relationships between fracture and matrix dimensions and can be calculated from theoretical equations.

Permeability Input Control

Porosity and permeability are independent rock properties. Total permeability in fractures is a function of fracture porosity, fracture permeability and matrix permeability. Permeability depends on the structure of the entire pore space of a rock including the pore throat size, and there are well established empirical relationships between these rock properties. This link is very well established in conventional reservoir rocks, and several equation exist in literature that link permeability to porosity, however in fractures reservoirs the relationship is much more complex. In homogenous formations, the flow of fluid towards the production wells can be simplified into flow within a channel, since the intrinsic of fracture permeability is independent of surrounding rocks.

Core analysis is conventionally used to determine matrix permeability rather than fracture permeability. It is usually difficult to distinguish between matrix permeability, fracture permeability and total permeability on core samples. Moreover, preparing a representative core sample in fractured zones is almost impossible, because the in situ properties are subjected to a greater change compared with non-fractured reservoirs.

Permeability derived from petrophysical evaluation is also generally matrix permeability. However, the sonic tool, that acquires Stonely waves, not only shows fluid inside the fractures on the borehole (indicating open fractures), but can also be used to have measurement of fracture permeability. Another direct measurement is from the well test analysis. If the dual porosity response is observed on the pressure derivative plot, then ratio between matrix and fracture permeability can be obtained. Permeability also can be calculated from the relationships between the fracture and matrix dimensions in the same way as porosity.

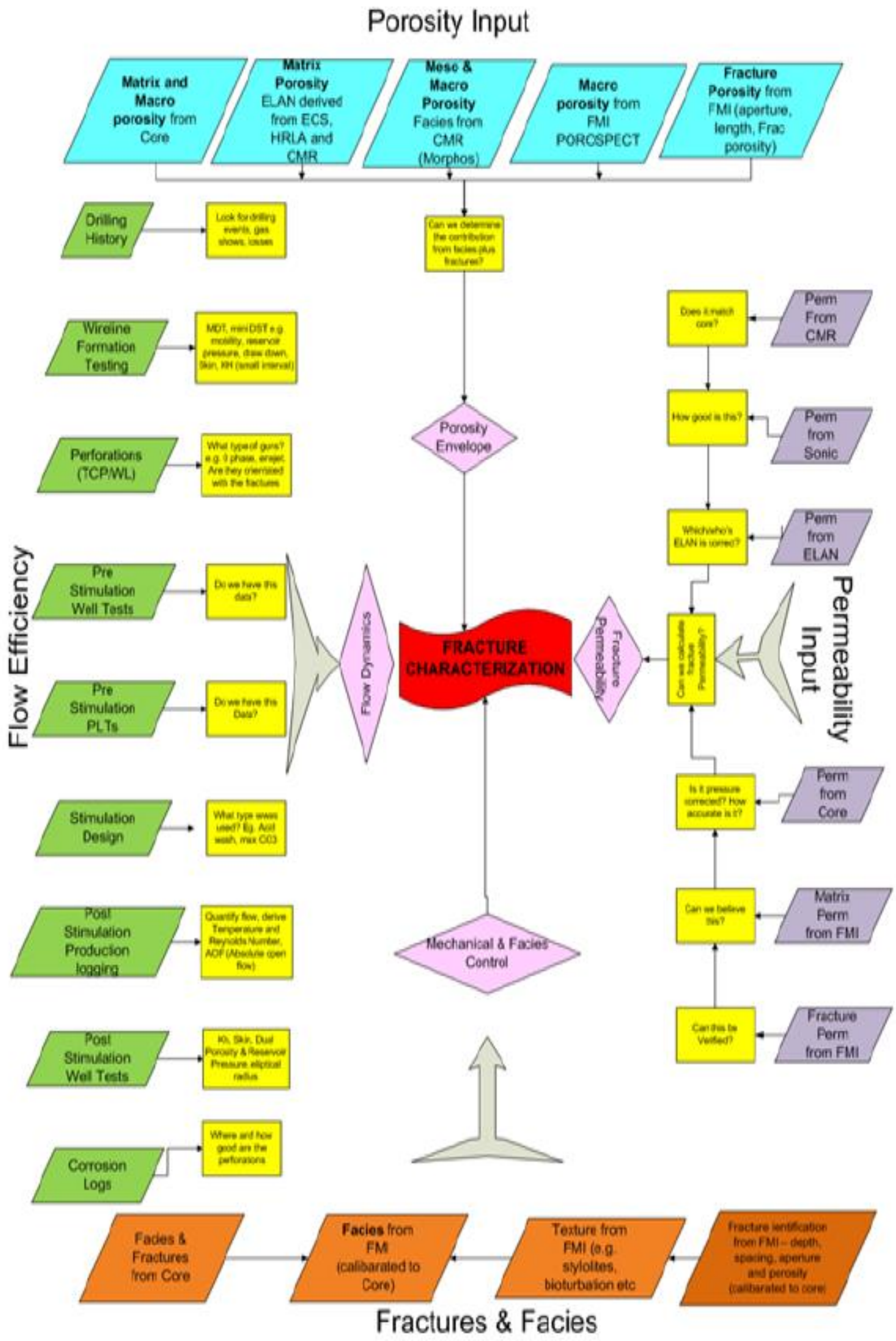
Flow Efficiency Control

As discussed, the flow efficiency in fractured reservoirs are related to the fracture characteristics such as aperture, length, density, connectivity and matrix porosity. Adding to an already complicated geological scenario, wells are often completed differently either as open-hole or cased-hole and perforated and produced co-mingled. During the analysis of flow data, it is often difficult to find a conclusive connection between fracture attributes and production. As matrix porosity can also play an important role and that production actually occurs from both matrix and fracture especially in carbonates or intercalated shales and sandstones.

Often it is observed that not all fractures were seen to contribute to flow, and this can be related to the effectiveness of the stimulation treatment. The main objective in stimulation is to create a conductive flow path and bypass the formation damage. Bypassing formation damage, therefore, improves connectivity between the well and the reservoir rock. This increases the well’s productivity or injectivity index by reducing skin. Accurate placement of any stimulation is critical, as the fluid tends to flow preferentially through high permeability zones, further increasing permeability and leaving the low permeability regions of rock untreated. In some cases, huge increases in water production are observed after a stimulation job because of the preferentially stimulated the high-permeability sections associated with water. To understand fracture characterisation it is important to understand whether the logging was post stimulation or pre, especially in a multiwall study.

Summary

It is clear that subsurface fracture evaluation is highly complicated and requires a holistic cross discipline approach to project management. Often the single failure of a fracture study is the lack and sporadic nature of the acquired data as well as the poor integration of the existing data. Clear objective well planning is needed, and often poor stimulation of the wells is the cause of poor production. Much work is needed to understand fractures especially in the light of the future of basement and shale gas exploitation.


Porosity Input
Matrix and Macro porosity from Core
Matrix Porosity ELAN derived from ECS, HRLA and CMR
Meso & Macro Porosity Facies from CMR (Morphos)
Macro porosity from FMI PORCSPECT
Fracture Porosity from FMI (aperture, length, Frac porosity)
Drilling History
Wireline Formation Testing
Perforations (TCP/WL)
Pre Stimulation Well Tests
Pre Stimulation PLTs
Stimulation Design
Post Stimulation Production logging
Post Stimulation Well Tests
Corrosion Logs
Flow Efficiency
Porosity Envelope
Flow Dynamics
FRACTURE CHARACTERIZATION
Fracture Permeability
Mechanical & Facies Control
Perm From CMR
Perm from Sonic
Perm from ELAN
Perm from Core
Matrix Perm from FMI
Fracture Perm from FMI
Permeability Input
Facies & Fractures from Core
Facies from FMI (calibarated to Core)
Texture from FMI (e.g. stylolites, bioturbation etc
Fractures & Facies

Storage and Fluid Flow Properties of Outcropping, Fractured Limestones of the Inner Apulian Platform, Southern Italy

La Bruna V.[1], Giuffrida A.[2], Castelluccio P.[2], Panza E.[3], Rustichelli A.[4], Tondi E. [4], Giorgioni M.[5], Agosta F.[2,3]

[1]*CEREGE-UMR, Aix-Marseille University, France*

[2]*Department of Science, University of Basilicata, Italy*

[3]*Geosmart Italia, Potenza, Italy*

[4]*School of Science and Technology, University of Camerino, Italy*

[5]*Shell Italia E&P, Rome, Italy*

This work defines the fracture stratigraphy of Lower Cretaceous, well-bedded, shallow-water limestones exposed at the Monte Alpi, southern Italy, and pertaining to the Inner Apulian Platform realm. These limestones are characterized by a wide spectrum of calcareous facies, pointing to a variety of depositional environments within a back-reef inner platform / platform margin of a vaste rimmed platform.

Fracture distribution is consistent with a prominent stratigraphic, and minor lithological controls on the development of Strata Bound (SB) and Non Strata Bound (NSB) fractures in the studied limestone succession. SB fractures are made up of bed perpendicular joints and sheared joints which terminate against bed interfaces and bed package interfaces. Differently, as documented by previous authors, NSB fractures formed by shearing and subsequent linkage of pre-existing features, and formation of new fracture sets. In fact, during burial diagenesis and subsequent tectonic evolution, bed interfaces and transgressive prominent surfaces related to transients of platform emersion affected the vertical growth of SB and NSB structural elements, respectively.

Furthermore, this study is aimed at deciphering the dimensional and geometric properties of the fracture network present within a nicely exposed footwall fault damage zone developed within the Lower Cretaceous limestones. Fault damage zone consists of a thick rock volume characterized by fractures and small faults that do not completely obliterate the original host rock features such a bed interfaces, but determine a higher fracture intensity with respect to the flanking host rock. Damage zones generally include structural elements that not only give information about kinematics and deformation history of faults, but also may play a fundamental role in the geofluid storage and fluid flow properties of carbonate rocks at shallow crustal levels.

Previous DFN-modelling based work conducted on the Outer Apulian Platform cropping out at the Murge Plateau and Gargano Promontory of southern Italy showed that primary heterogeneities (e.g. bedding) played a fundamental role in the compartmentalization of SB fractures, which profoundly impact the computed values of fracture porosity and permeability of the carbonate matrices away from major fault zones. Differently, the fault damage zones are mainly crosscut by NSB fractures. The computed analysis highlighted the significant role played by NSB fractures on the amount of fracture porosity computed for the Highly Fractured Damage Zone (Fig. HFDZ), in fact there is an increase of up two orders magnitude from the host rock to the fault damage zone. Hence the highly fractured fault damage zone flanking the fault core forms the main repository for subsurface geofluids, as already documented for other limestone-hosted normal faults of central and southern Italy.

The present work is hence focused on the computation of both fracture porosity and equivalent fracture permeability by DFN modelling of ca. 350 m^3 geocellular volumes, which are representative of the study outcrops. In order to gather the required information on the dimensional and scalar properties of individual fracture sets, both away from major fault zones, and within the study fault damage zones, two different methods were taken. First, traditional scanline analysis, oriented parallel to the bedding analysis, was carried out in several outcrops. Then, a digital scanarea method was also applied by using a FracPaq through digital images analysis for the unstable and sub-vertical outcrops. Application of these two techniques allows us to compare and contrast the results of DFN modelling in light of the input data.

As a result, the mean value of computed fracture porosity spans between ca. 0.013% and 0.13% for the host rock considering input data after scanline and scanarea methods, respectively. Similarly, the mean, equivalent, horizontal fracture permeability varies between 10^{-4} and 10^{-3} mD considering the same data input, respectively. Considering the studied fault damage zone the mean value of computed fracture porosity spans between ca. 0.85% and 0.5% for the host rock considering input data after scanline and scanarea methods, respectively. Differently, the mean, equivalent, horizontal fracture permeability shows a very small variation, being all in the range of 10^{-2} mD for the two data sets considered as input data for DFN modelling.

A similar trend was documented by other authors for the high-angle fault zones crosscutting the Cretaceous platform limestones of the Altamura Fm. exposed in the Murge Plateau (southern Italy), and within the Oligocene-Miocene ramp carbonates of the Bolognano Fm. exposed in the Majella Mt. (central Italy), both pertaining to the Apulian Platform paleogeographic realm.

Finally, results of DFN modelling also suggest the importance of the field structural methods employed for quantitative fracture analysis of SB fractures. In fact, a difference of about 1 order of magnitude is computed for both fracture porosity and equivalent permeability by considering fracture intensity data obtained after scanline and scanarea methods. Since no difference was found for NSB fractures, we also conclude that the methods chosen for a quantitative field fracture analysis might affect the results of computed fracture intensity values only when fractures are strongly compartmentalized within discrete mechanical units. At the scale of m-wide outcrops, these units may correspond to individual limestone beds, which do not affect the computed NSB fracture intensity values within the fault damage zones.

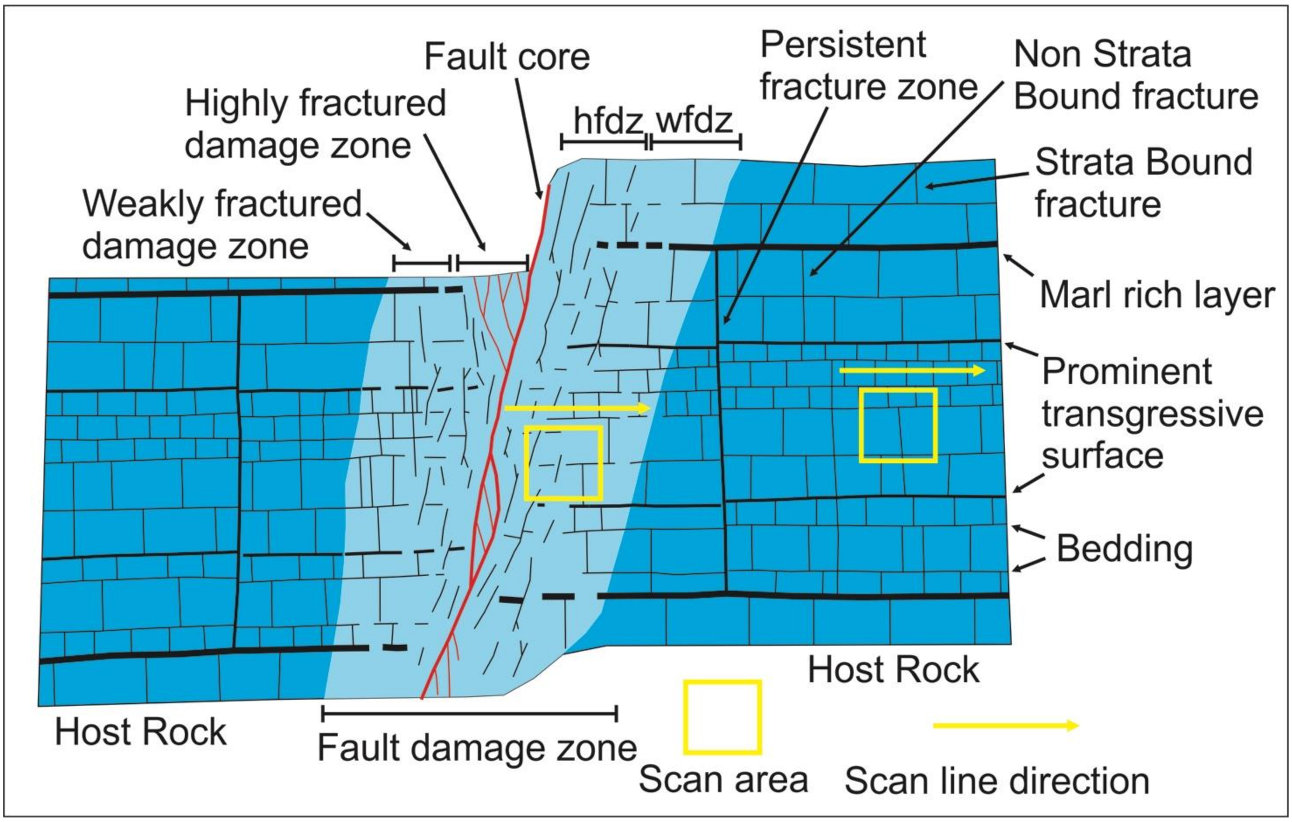


Fig.1 – Schematic representation of the studied rock volume and the main structural elements collected alng the scan areas and the scan lines.

Practical experiments on modelling the connectivity of fracture networks

Oscar Fernandez
Independent consultant

Fracture network connectivity is one of the key parameters controlling the permeability in fractured reservoirs. It is commonly understood that a well-connected fracture network will have better permeability to water and hydrocarbons. In reservoirs where fractures are sealed, fracture network connectivity will lead to overall permeability reduction. It can also be assumed that connectivity is a function of fracture intensity, fracture orientation and fracture dimensions. However, characterizing and quantifying fracture network connectivity exclusively from subsurface data is often not stratightforward. On the one hand, fracture intensity and orientation can be calculated at the wellbore scale and extrapolated with relative confidence, but fracture dimension is normally highly unconstrained. On the other, tortuosity in connected fracture networks is also an important factor that cannot be quantified easily. Finally, representing fracture connectivity in functional reservoir models that can be run and matched in reasonable time frames requires simplifying fracture network complexity to parameters such as permeability and porosity, in which the nuances of connectivity and tortuosity can be easily lost.

In this presentation I will discuss three case studies. In these examples the fracture network connectivity has been characterized and quantified from different data sources: wellbore images, well tests, and outcrop analogues. To represent each one of these fracture networks, three different approaches were used. In one, gridding was the key element to model fracture network anisotropy. In another mechanistic modeling was used to estimate equivalent fracture network properties, including the impact of connectivity on both conductive and sealed fracture networks. And in the last example, geostatistical modelling was used to represent the variability in fracture network connectivity throughout the reservoir.

The influence of structure, stratigraphy and observation-scale on fracture attributes: a case study from Swift Anticline, NW Montana

Adam J. Cawood[1*], Clare E. Bond[1], Hannah Watkins[1], Mark Cooper[1,2] and Marian J. Warren[3]
[1] *School of Geosciences, University of Aberdeen, UK*
[2] *Sherwood GeoConsulting, Calgary, Canada*
[3] *Jenner GeoConsulting, Calgary, Canada*

Swift Anticline is a thrust-related frontal structure of the Sawtooth Range, NW Montana. Excellent exposure of fractured Mississippian Madison Group carbonates across this reservoir-scale structure make it a suitable outcrop analogue to fractured carbonate reservoirs in fold-thrust belts, particularly of the laterally-equivalent Western Canada Sedimentary Basin. The frontal anticlines of the Sawtooth Range have been important sites for field-based appraisal of fracture patterns, particularly with respect to the link between folding and fracturing. Several of these outcrops have provided field data for work on predicting fracture orientations in folded strata (e.g. Stearns, 1964). Observed fracture patterns at Swift, however, are complex and vary significantly in 3D. Further, they do not appear to conform to existing models of fracture orientations in contractional settings. In this study we adopt a combination of field-based and digital interpretation approaches: we supplement field measurements of fracture attributes with virtual outcrop derived data. This approach allows fracture attributes (orientation, intensity and length) to be extracted at a range of scales, through several structural, stratigraphic and along-strike positions.

Results show that measured fracture attributes at Swift Reservoir are primarily influenced by structural position: bedding-normal Mode I fractures are dominant in strongly deformed zones of high curvature while mode II fractures record increases in intensity and length-scale on gently dipping back-limb positions. Along-strike variation in fracture orientations records asymmetry along the anticline axis and highlights several fracture corridors which serve as lateral accommodation structures in the fold. Variation in fracture orientations through the stratigraphy are impacted both by mechanical properties of units, and by the presence of discrete mechanical boundaries along which strain was apparently localised during deformation. Finally, data derived from a range of scales (field-based; high-resolution virtual outcrop; satellite imagery) record significant variation in measured fracture attributes as measurement scale changes.

The combination of detailed digital mapping and fieldwork allows characterisation of fracture patterns at multiple scales, stratigraphic levels and structural positions. This approach highlights complex and variable fracture patterns at Swift Anticline which do not wholly conform to existing models of fracture development. Based on our data, we suggest that predicting fracture patterns in folded strata is not straightforward. The influence of multiple factors, including mechanical stratigraphy, structural position and scale-of-observation should be accounted for when attempting to make predictions of fracture patterns in the subsurface.

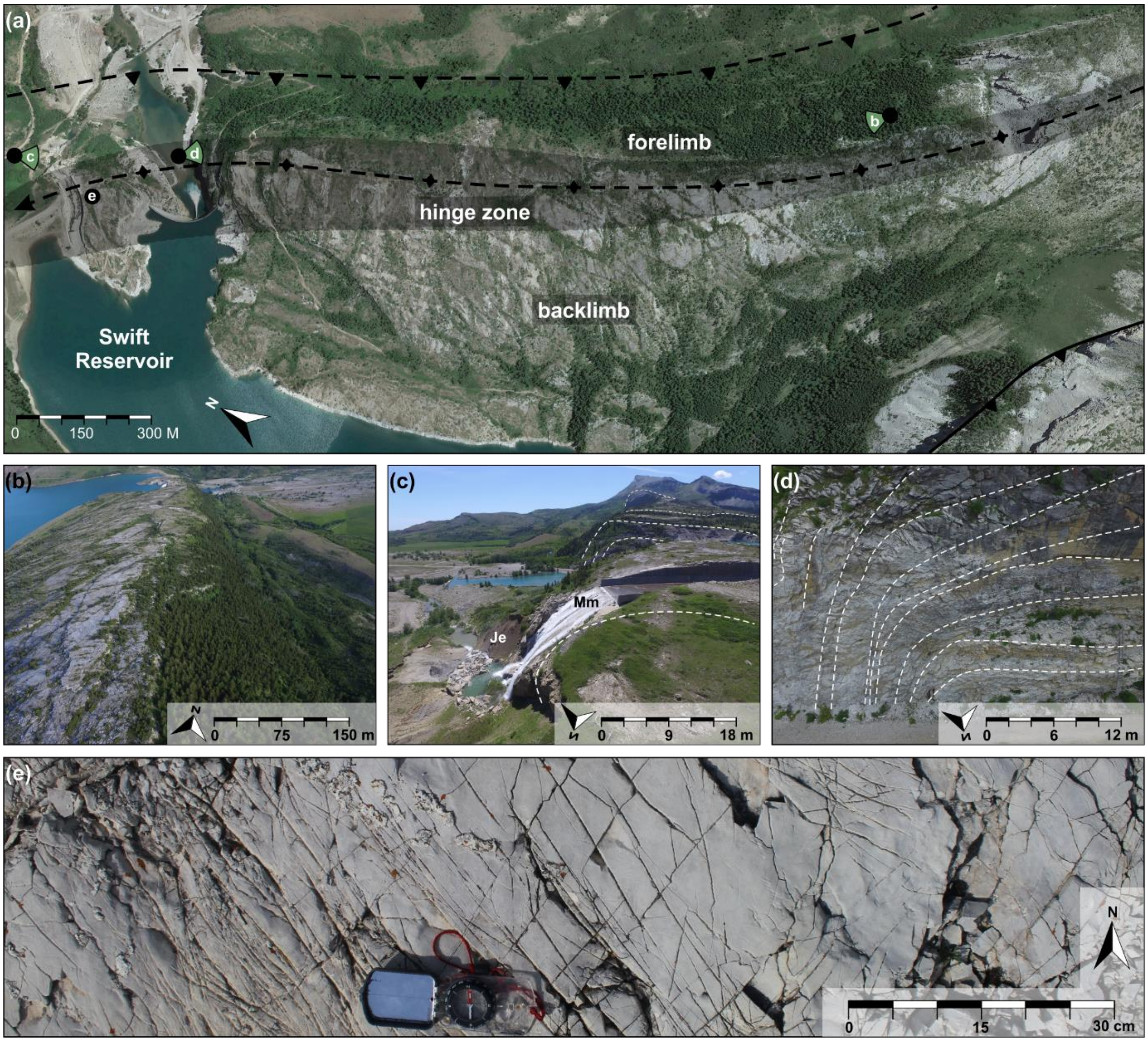


Fig. 1: Satellite, UAV and ground-based imagery of fractured bedding surfaces, Swift Anticline, NW Montana

3D model of a km-scale outcrop analogue of fractured hydrocarbon reservoirs: the Gozo Island

Mattia Martinelli[1]**,** Andrea Bistacchi[1], Fabrizio Balsamo[2], Marco Meda[3]
[1] Università degli Studi di Milano Bicocca, Piazza dell'Ateneo Nuovo, 1 - 20126, Milano
[2] NEXT- Natural and Experimental Tectonics research group, Università di Parma, Dipartimento Scienze Chimiche, della Vita e della Sostenibilità Ambientale, Padiglione Scienze della Terra, Campus Universitario, Parco Area delle Scienze 157/A, 43124 Parma, Italy
[3] ENI Spa, Upstream and Technical Services - San Donato Milanese – Italy.

Outcrop analogues have an important role in hydrocarbon exploration and reservoir characterization because they can help filling the gap between seismic and borehole scale. In this work, we present results from our project in the Gozo Island (Maltese Archipelago). Here, a Late Oligocene-Early Messinian carbonatic sequence, composed by different types of carbonates, was affected by two main extensional tectonic events leading to the formation of a complex fracture pattern: i) E-W extension during the Aquitanian ii) N-S extension from the Middle Miocene onwards. We have reconstructed a 3D geological model covering all the Gozo Island (15 x 8 km) using detailed geological maps and borehole data. The geological model has been populated with data regarding the distribution of fracture networks (from photogrammetric DOMs), mechanical stratigraphy and petrophysics using different geostatistical approaches.

Fracture attribute characterization in outcrop analogues by a combined field and multiscale photogrammetry approach: insights from platform carbonates folded in the Pag anticline, External Dinarides of Croatia

Andrea Succo[1], Silvia Mittempergher[2]*, Andrea Bistacchi[2], Mahtab Mozafari[1], Pierre Olivier Bruna[3], Marco Meda[4] & Fabrizio Storti[1]

[1] *NEXT – Natural and Experimental Tectonics research group, Università di Parma, Dipartimento di Scienze Chimiche, della Vita e della Sostenibilità Ambientale, Parco area delle Scienze 157/A, 43124 Parma, Italy*

[2] *Università degli Studi di Milano Bicocca, Department of Environmental and Earth Sciences, Piazza della Scienza 4, 20126 Milano*

[3] *TU Delft, Department of Geoscience and Engineering, Applied Geology section, Stevinweg 1, 2628 CN Delft, The Netherlands*

[4] *ENI Spa, Upstream and Technical Services – San Donato Milanese - Italy*

Field analogues allow detailed studies of fracture networks to improve fracture pattern predictions in reservoirs. Different type of fractures and their patterns at different scale exert a fundamental influence on the mechanical (e.g. strength) and transport (e.g. fluids) properties of rocks. Quantitative studies on outcrop analogues, for understanding the relationships between the origin of fractures and their geometrical attributes and spatial distributions, are fundamental for obtain scaling laws as a function of mechanical stratigraphy and the evolution of folding and/or faulting mechanisms.

In this contribution, we describe the preliminary results of a structural study carried out in the Pag anticline, a 30 km-long fold that is very well exposed in the homonymous island, in the External Dinarides (Croatia). The Pag anticline represents a good field analogue for folded and faulted tight platform carbonates where integrating field-based structural and stratigraphic analysis, microstructural and petrographic observations, and digital-mapping techniques on Digital Outcrop Model (DOMs) based on “close-range” photogrammetry, to obtain large and robust datasets of fracture attributes.

The Pag anticline involves about one km of Cenomanian to Senonian layered rudist-bearing platform carbonates, overlain by about 250 m of early-Eocene Foraminiferal limestones and by an late-Eocene to Miocene thrust-top basin succession consisting of about 250 m of siliciclastic Dalmatian Flysch. In cross section, the anticline shows an asymmetrical box-type geometry, with high angle to overturned limbs and a wide flat crestal zone. The fold is dissected by major backthrusts and forethrusts, and by two compartmentalized main sets of strike-slip faults, striking respectively N-S and E-W. Along-strike fold shape, deformation style, and deformation patterns, shows an important variability that can be explained with a progressive differential fold tightening offset by cross-fold strike-slip fault systems. At meso- to micro-scale, the deformation pattern consists of a complex array of veins and stylolites that formed before, during, and after folding and faulting. Petrographic and microstructural analysis helped to unravel the timing of different deformational stages and to reconstruct the fracturing history. To characterize the fracture network at multiple scales, we integrated field surveys with satellite imagery and DOMs reconstructed from drone to ground-based photogrammetry. DOMs were used to obtain 3D fracture networks and to create virtual bedding-parallel and bedding-perpendicular planar sections. Field and virtual linear scanline and scan area have been carried out in different tectonic domains of the anticline. A hierarchical organization of fractures is observed, including (1) hectometer-scale fracture corridors crosscutting the whole folded succession, (2) through-going fractures cutting several mudstone beds, (3) strata-bound fractures and (4) a pervasive network of fractures shorter than bed thickness. Our preliminary results suggest that this multidisciplinary approach combining field and lab data with multiscale photogrammetry provides reliable results to better understanding the structural framework and fold evolution and can effectively increase the statistical strength of field-based fracture quantification studies.

Fracture analysis of Qara Chauq outcrops as analogue to support Qara Chauq subsurface model, Zagros Fold and Thrust Belt, Kurdistan Region, Iraq

Abdullah Awdal[1,2] Mohammed Ibrahim[2]
[1]Department of Natural Resources Engineering and Management, School of Science and Engineering, University of Kurdistan Hewlêr, 30 Meter Avenue, Erbil, Kurdistan Region, Iraq
[2]Kar Energy, Building J, Apartment 8, 1st Floor, Naz City, Erbil, Kurdistan Region, Iraq

Most hydrocarbon reserves are stored in naturally fractured reservoirs and such fracture systems can therefore have a significant impact on reservoir performance. Fractures are one of the most important paths for fluid flow in carbonate reservoirs, and industrial geoscientists and engineers therefore need to understand and study fracture patterns in order to optimise hydrocarbon production. The observed fracture patterns in outcrops may have implications on fluid flow and reservoir modelling in subsurface reservoirs, and we have therefore undertaken a case study of fracturing associated with folding in Iraqi Kurdistan. Qara Chauq Central (QCC) and Qara Chauq North (QCN) anticlines are the studied structures which are located nearby Kirkuk Field. Butmah Formation of Lower Jurassic is the main reservoir and considered as a Type-II fractured reservoir, where the matrix provides oil storage and the fractures provide the flow pathways. Based on surface field work and review of dynamic data, both small-scale fractures (diffuse fractures, joints) and large-scale fractures (corridors, faults) could be present at the Butmah level. Small-scale fractures are responsible for matrix-fracture fluid exchanges (water imbibition and/or gas gravity drainage), whereas large-scale fractures are often responsible for early water breakthroughs when the contrast in permeability between the matrix or diffuse fracture on the one hand, and the corridors on the other hand is large.

Fracture attributes such as orientation and density are collected from Qara Chauq outcrops. These outcrops of Oligocene age are the main reservoir units in the nearby Kirkuk and Bai Hassan oil fields. Fracture orientations show a clear relationship to the local fold axis in both Qara Chauq Central and North anticlines, although in some cases they appear to relate more to the present day *in-situ* maximum horizontal stress direction or local faulting. At the QCC structure, 2 major sets (N30 and N80) and 1 minor set (N140) are observed in the NE flank, and 1 major set (N90) and 1 minor set (N00) are observed in the SW flank. These preferred fracture orientations (N30 & N80 for NE flank and N90 for SW flank) will introduce a certain degree of anisotropy in the resulting fracture permeability.

Project Title: Analysis of Critically Stressed Fractures in the Shaikan Field, Kurdistan Region of Iraq

Callum J. Gilchrist[1] (Supervisors: Prof. John W. Cosgrove[1] and Kevin Parmassar[2])
[1]Imperial College London, [2]Gulf Keystone Petroleum (UK) Ltd.

Critically stressed fractures can make up a significant proportion of the fracture systems of many fractured reservoirs around the world. There is currently no consensus regarding the significance of these fractures within reservoirs and their effects on production performance. This thesis calculates the present-day stress regime within the Shaikan Field, in the Kurdistan Region of Iraq. Wireline logs and Leak-Off Test (LOT) data are utilized to produce one dimensional mechanical earth models (1D MEMs) for eight wells. With fracture orientations measured from formation micro-resistivity image (FMI) logs, those that are critically stressed are calculated using the present-day stress regime. The results show that the present-day stress regime within the Shaikan Field is strike-slip, and *c.*5-20% of fractures are critically stressed. Further analysis shows that the proportion of critically stressed fractures varies with stratigraphic formation, spatial positioning and with depth. Two possible models are presented for determining how the stress regime behaves during production, reservoir pressure change and poroelastic response. One predicts that the fracture system remains critically stressed and the other that it becomes more stable. Possible reasons for these differences are discussed. Critically stressed fractures may enhance permeability or impede fluid flow connectivity within the reservoir, and thus may have positive or negative effect on reservoir performance.

Burlington House
Fire Safety Information

If you hear the Alarm

Alarm Bells are situated throughout the building and will ring continuously for an evacuation. Do not stop to collect your personal belongings.

Leave the building via the nearest and safest exit or the exit that you are advised to by the Fire Marshal on that floor.

Fire Exits from the Geological Society Conference Rooms

Lower Library:
Exit via main reception onto Piccadilly, or via staff entrance onto the courtyard.
Lecture Theatre
Exit at front of theatre (by screen) onto Courtyard or via side door out to Piccadilly entrance or via the doors that link to the Lower Library and to the staff entrance.
Main Piccadilly Entrance
Straight out door and walk around to the Courtyard.

Close the doors when leaving a room. **DO NOT SWITCH OFF THE LIGHTS**.

Assemble in the Courtyard in front of the Royal Academy, outside the Royal Astronomical Society. Event organizers should report as soon as possible to the nearest Fire Marshal on whether all event participants have been safely evacuated.

Please do not re-enter the building except when you are advised that it is safe to do so by the Fire Brigade.

First Aid

All accidents should be reported to Reception and First Aid assistance will be provided if necessary.

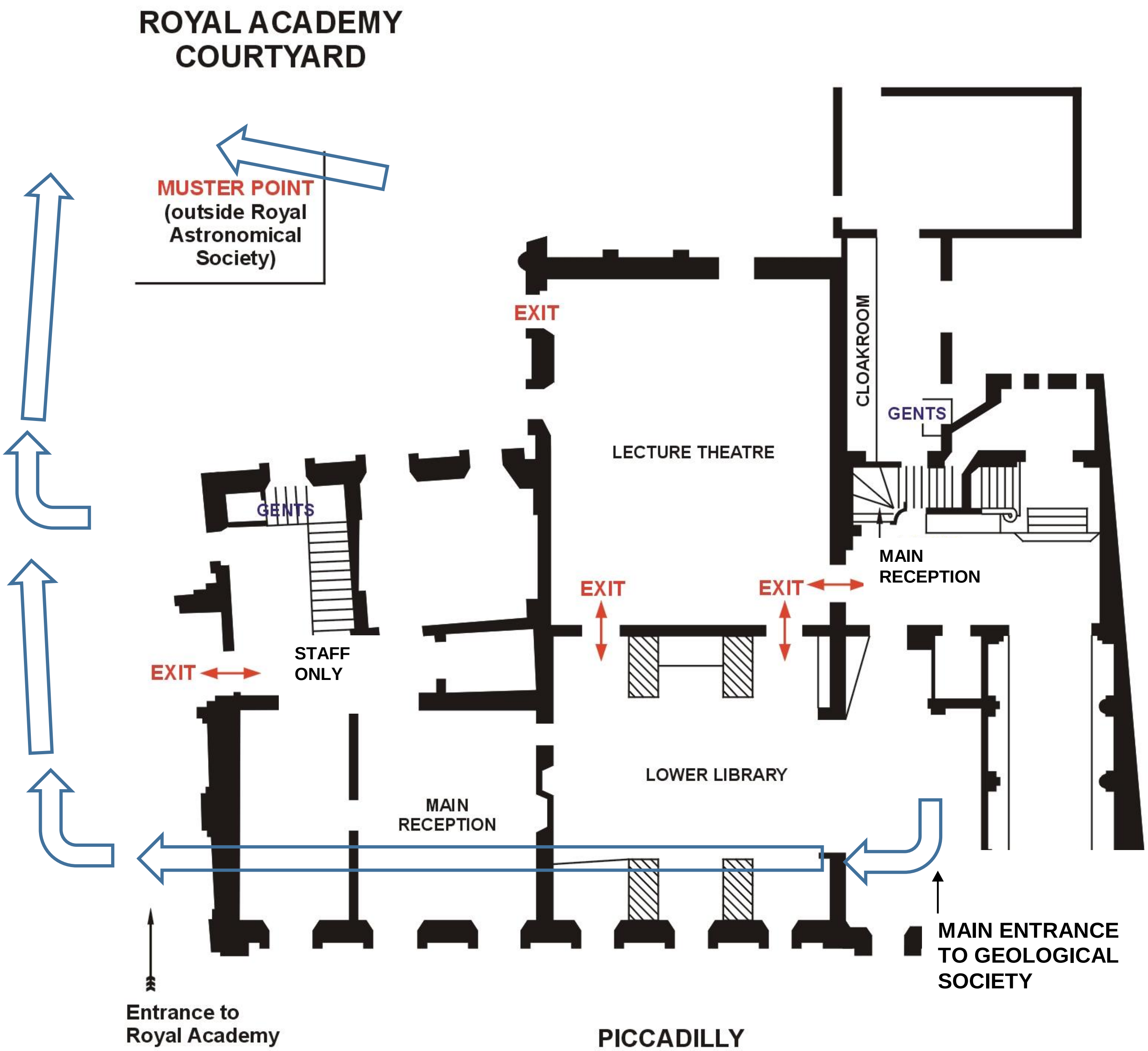
Facilities

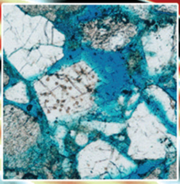
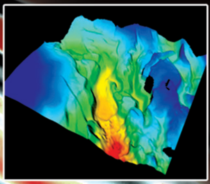
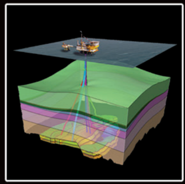
The ladies toilets are situated in the basement at the bottom of the staircase outside the Lecture Theatre.

The Gents toilets are situated on the ground floor in the corridor leading to the Arthur Holmes Room.

The cloakroom is located along the corridor to the Arthur Holmes Room.

Ground Floor Plan of the Geological Society, Burlington House, Piccadilly



The Geological Society

serving science & profession

Corporate Supporters:

bp

equinor

Convenors:

Richard Diggens
BP – Chairman

Chris Samson
Independent – Secretary

Hozefa Godhrawala
Centrica

Chris Hayes
RPS

Tim Herrett
Independent - Co Chair

Rachael Horton
BP

Maxim Kotenev
Sasol

Christine Telford
Independent

Event Sponsors:

Gaia

HRH GEOLOGY

petrolink

STAG Geological Services Limited

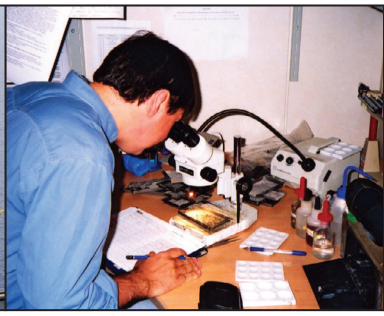
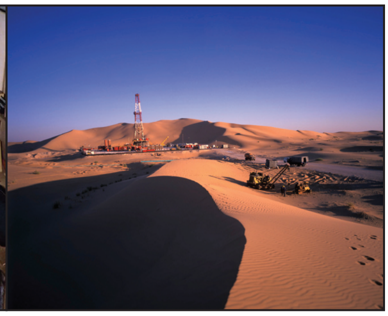
RPS

Registration now open

Operations Geoscience Adding Value

7-8 November 2018

The Geological Society, Burlington House, Piccadilly, London

The main focus will be on the value operations geoscientists deliver and the pivotal role they play via the following topics:

- **The value of learning lessons well** – what is a lesson?; how are lessons learned and managed (e.g. avoiding non productive/invisible lost time)?; practical examples of lessons with demonstrable change; personal willingness to share failure/sub optimal performance
- **Risks and safety of operations** – identifying, managing, communicating risks and planning contingencies effectively
- **Formation pressure and geomechanics** – sharing good practice, techniques and knowledge, prediction and detection methods
- **The value of managing and interpreting data** – effective data management for field life, examples of cross company collaboration

Overarching themes:

- Value of these themes to **well life cycle**
- Sharing real world **examples and case studies**
- Importance of **personal behavioural skills** throughout (leadership, communication, relationship building and influencing others)
- Share good practice, showcasing **innovative approaches and technologies**

We look forward to active participation from our colleagues across subsurface, drilling and engineering disciplines to significantly broaden the main conference themes.

There will be a parallel poster session in the library.

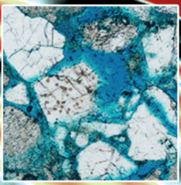
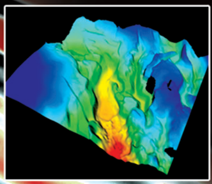
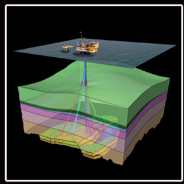
For further information and registration please contact:

Sarah Woodcock, The Geological Society, Burlington House, Piccadilly, London W1J 0BG.
T: +44 (0)20 7434 9944 or email: sarah.woodcock@geolsoc.org.uk

PETROLEUM GROUP

At the forefront of petroleum geoscience

www.geolsoc.org.uk/petroleum
#PGOpsGeo18

The Geological Society

serving science, profession & society

Call for Abstracts: 14 December 2018

Celebrating the life of Chris Cornford (1948-2017)

Petroleum Systems Analysis 'Science or Art?'

24-25 April 2019

The Geological Society, Burlington House, London

Approaches to tackling the scientific and practical questions in the fields of Petroleum Geochemistry and Petroleum Systems Analysis range from the entirely theoretical to the empirical. Chris Cornford embraced both in his working life. The integrated approach he espoused will form the basis of the technical programme for the Conference covering two themes:

- Recent developments in the use of data including integration of models and (big) data; use of visualisation and data exploration or mining techniques.
- Topical issues & controversies ranging from mass balance approaches, petroleum migration to specific modelling studies and practical applications.

The Conference will be inspired by Chris' ethos of innovation, encouragement of youth and challenging received wisdom.

Call for Abstracts:

Please submit abstracts for oral and poster contributions that cover any of the above themes to sarah.woodcock@geolsoc.org.uk before 14 December 2018

For further information please contact:

Sarah Woodcock, The Geological Society, Burlington House, Piccadilly, London W1J 0BG.
Tel: +44 (0)20 7434 9944 or email: sarah.woodcock@geolsoc.org.uk

Corporate Supporters:

bp

equinor

Convenors:

Steve Lawrence
Subsurface Resource Consulting

Dan Cornford
IGI Ltd

Elin Rein
Equinor

David Gardiner
IGI Ltd

Abhen Pather
RPS Energy

Mark Groves Gidney
Energetical

Richard Bray
Subsurface Resource Consulting

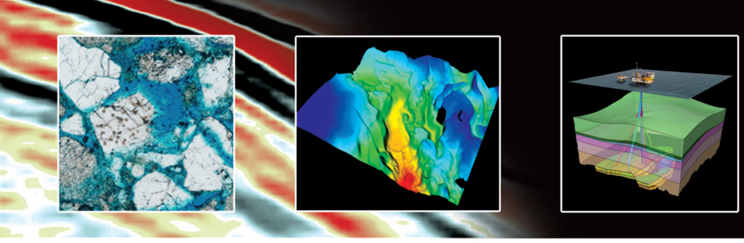
John Argent
Sound Energy

Mark Osborne
BP

PETROLEUM GROUP

At the forefront of petroleum geoscience

www.geolsoc.org.uk/petroleum



The Geological Society

serving science, profession & society

Corporate Supporters:

bp

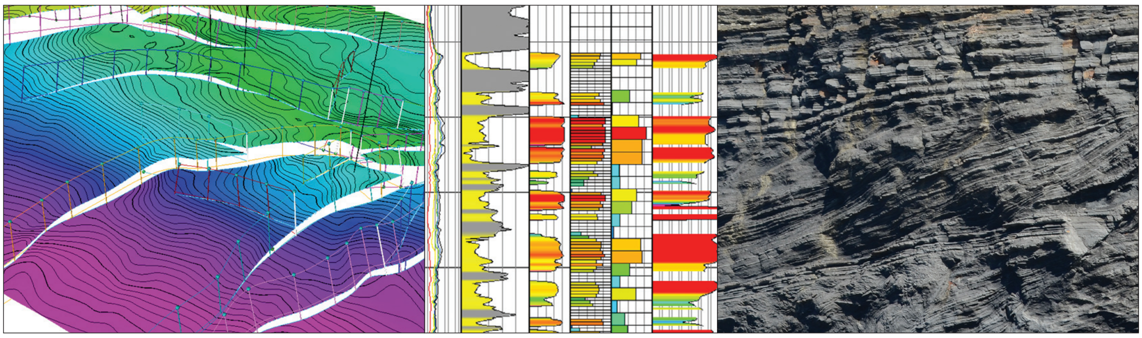
equinor

Call for Abstracts – Deadline: 29 March 2019

Capturing Geoscience in Geomodels

26-27 June 2019

Robert Gordon University, Aberdeen



Over recent years the construction of 3D static and dynamic reservoir models has become increasingly complex. With the availability of extensive tools and technology it is important not to forget the objective of the modelling process.

As we develop our hydrocarbon fields it is essential that 3D Static Models be built with fit-for-purpose geological models, honouring the geological, geophysical and petrophysical data that they are created from.

This two-day conference will explore how geoscience information should be used to best effect, and how to identify when geoscience data may no longer add value. Sessions will include the following themes:

- Data integration: seismic, well log, sedimentological, core dynamic data and beyond
- Capturing conceptual geology in reservoir modelling for different settings and depositional environments
- Scale: geology vs model vs data
- Uncertainty: dealing with geological uncertainty in modelling and understanding its benefits and limitations
- Embracing new modelling technology and approaches.

Call for Abstracts:

Please submit talk or poster abstract to sarah.woodcock@geolsoc.org.uk by 29 March 2019.

For further information please contact:

Sarah Woodcock, The Geological Society, Burlington House, Piccadilly, London W1J 0BG.
Tel: +44 (0)20 7434 9944

Convenors:

Matt Jameson
Glencore

Gwilym Lynn
Shell

Leigh Truelove
Schlumberger

Ingrid Demaerschalk
Tullow

Alun Griffiths
Rockhopper

Catherine Tonge
Shell

David Hulme
Equinor

Tom Marsh
Rock Flow Dynamics

James Aguas
Halliburton

Sponsored by:

RFD Rock Flow Dynamics

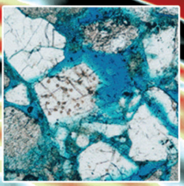
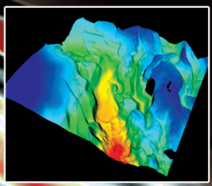
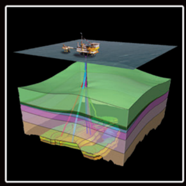
Schlumberger

HALLIBURTON

PETROLEUM GROUP

At the forefront of petroleum geoscience

www.geolsoc.org.uk/petroleum

The Geological Society

serving science, profession & society

Corporate Supporters:

bp

equinor

Call for Abstracts – Deadline: 1 December 2018

Hydrocarbons in Space and Time

9-11 April 2019

The Geological Society, Burlington House, Piccadilly, London

Convenors:

Owen Sutcliffe
Halliburton

Frans van Buchem
Halliburton

Mark Houchen
Shell

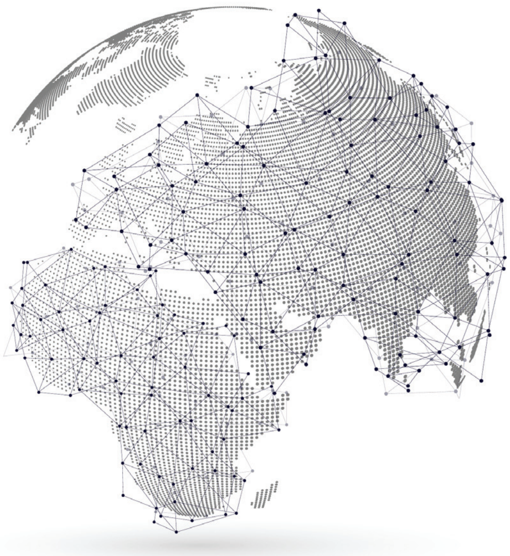
Bruce Levell
Oxford University

Hannah Steaggles
BP

Mike Simmons
Halliburton

Keynote Speakers:

A diverse set of keynote speakers are being solicited from across the community



The global endowment of hydrocarbons is markedly uneven both spatially and temporally. In the 1990s, several key papers recognised that distinct stratigraphic and paleogeographic trends exist and that this knowledge was an important guide to successful exploration. So, what has changed in 30 years?

The industry has moved into new frontiers and basins, drilled deeper, found new plays and gone through a revolution that has brought unconventional resources to the fore. It is therefore timely to consider how our knowledge of the distribution of hydrocarbons in time and space has changed. What new insights have we gained? Can this new understanding be used to be better at predicting new hydrocarbon discoveries?

This 3-day conference will seek to share recent advances and case studies and will be built around four main themes:

- The known global heterogeneity of hydrocarbon resources – including source rocks
- The controls on heterogeneity – including palaeoclimates and geodynamics
- The geological and data science tools to aid prediction
- What our present understanding means for future exploration

Event to be accompanied by a post-conference field trip to the Wessex Basin.

For further information please contact:

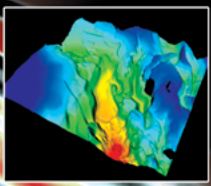
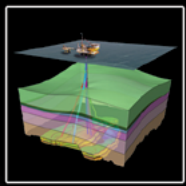
Sarah Woodcock, The Geological Society, Burlington House, Piccadilly, London W1J 0BG.
Tel: +44 (0)20 7434 9944 or email: sarah.woodcock@geolsoc.org.uk

For Abstract Guidelines, please download a copy from the website:
https://www.geolsoc.org.uk/PG-Hydrocarbons-in-Space-and-Time

PETROLEUM GROUP

At the forefront of petroleum geoscience

www.geolsoc.org.uk/petroleum

The Geological Society

serving science, profession & society

Corporate Supporters:

bp

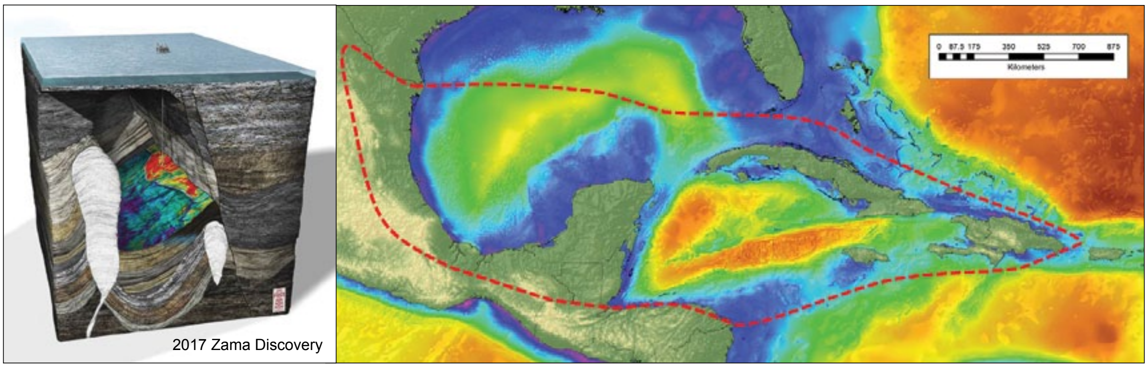
equinor

Call for Abstracts – Deadline: 30 November 2018

Petroleum Geology of Mexico and the Northern Caribbean

14-16 May 2019

The Geological Society, Burlington House, Piccadilly, London



2017 Zama Discovery

The Gulf of Mexico is a world class prolific hydrocarbon system. As a result of recent energy reform the Mexican sector of this basin has been open to international companies for the first time through a series of competitive licence rounds. The first phase of drilling on these newly awarded permits has resulted in the discovery of giant hydrocarbon accumulations in the Mexican offshore sector. Geologically, the offshore and onshore basins of Mexico offer a diverse range of play types with multiple source / reservoir pairs and are characterised by complex tectonic evolution with associated halokinesis and shale tectonics.

More widely within the Northern Caribbean region, exploration activities are ongoing in several countries targeting both proven and frontier petroleum systems. Some of these play elements are potential extensions of the proven systems in Mexico. While geologically complex, these areas have the potential to emerge as major hydrocarbon basins.

This regional conference aims to bring together both academic and industry geoscientists together to discuss the current state of understanding of the geology and petroleum systems in these geologically complex, but prolific hydrocarbon basins.

The committee now invite submissions of abstracts along the following themes

- Regional Plate Tectonic Evolution
- Basins of Mexico and the Northern Caribbean
- Onshore Basins and the Laramide and Chiapas Fold Belt effects
- Petroleum Systems
- Exploration & Production History
- Neogene Clastic Depositional Systems
- Carbonate Depositional Systems
- Salt Tectonics
- Controls on hydrocarbon habitat – seal capacity
- Relevant GOM Analogues

Call for Abstracts:

Please submit talk or poster abstract to sarah.woodcock@geolsoc.org.uk by 30 November 2018.

For further information please contact:

Sarah Woodcock, The Geological Society, Burlington House, Piccadilly, London W1J 0BG.
Tel: +44 (0)20 7434 9944

Convenors:

Jonathan Hull
Ophir Energy – Chair

Matthew Bowyer
Cairn Energy

Ian Davison
Earthmoves

Mike Hohbein
Ophir Energy

Aruna Mannie
Premier Oil

Chris Matchette Downes
CaribX

Adrian Neal
Badley Ashton

Mark Shann
Sierra Oil & Gas

Sponsored by:

Cairn

earthmoves

ERCE
Independent Energy Experts

ophir

PremierOil

PETROLEUM GROUP

At the forefront of petroleum geoscience

www.geolsoc.org.uk/petroleum