



Handling Fault Seals, Baffles, Barriers and Conduits: Cost Effective & Integrated Fault Seal Analysis

15 - 17 November 2017

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Handling Fault Seals, Baffles, Barriers and Conduits: Cost-Effective and Integrated Fault-Seal Analysis

15 – 17th November 2017

Geological Society of London, Petroleum Group
Burlington House, London

Welcome to the Fault Seal Conference, which has been organized by the Petroleum Group of the Geological Society. Here, you will find the programme and the abstracts for all of the talks and poster presentations over the three days of the conference. Also, information on the meeting can be found using the Petroleum Group Conference Application, downloadable for free from all app stores.

The organizing committee would like to thank the corporate sponsors (BP and Statoil) and conference sponsors, Midland Valley, Badleys and Saudi Aramco for their support of this event. The Petroleum Group and the Geological Society would not be able to continue to organize events of this scale without continued industry sponsorship.

Faults are a key component of heterogeneity in reservoirs. They can trap/seal hydrocarbons or be barriers/baffles to fluid flow in a producing field. Whether or not they seal or act as a barrier to fluid flow is crucial in every part of the petroleum value chain – from prospect generation to development well planning. This meeting will cover all aspects of fault analysis starting with processes and definitions, through to laboratory & geomechanics-, field-, modelling-based studies, and finishing with application to hydrocarbon exploration and production. Despite these categories, there will be a big focus upon data integration, and fit for purpose workflows, to address the risks and uncertainties associated with fault related fluid flow in today's working environment. This does not solely apply to the hydrocarbon value chain as the topics have relevance to other industries such as water and nuclear waste disposal. Well established workflows (such as juxtaposition and shale gouge analysis) and gap areas (e.g., carbonates, geomechanics, and treatment of sand-sand contacts) will be identified.

Our thanks go to the Geological Society staff for their help and organization, particularly Sarah Woodcock for her hard work. We would like to thank all contributors for their abstracts, presentations and posters. Finally, a very big thankyou to all the conference attendees; we hope that you will find the meeting interesting and enjoyable, with plenty of opportunities to exchange ideas and learn something new.

Convenors:

Steve Ogilvie (Aker BP)
Wayne Bailey (Woodside)
Steve Dee (BP)
Woody Wilson (BP)

Reference:

Abstracts of 'Handling Fault Seals Baffles, Barriers and Conduits: Cost Effective and Integrated Fault Seal Analysis', Petroleum Group of the Geological Society of London, Burlington House, London, UK, 15-17 November 2017.

PROGRAMME

CONFERENCE PROGRAMME

Day One	
08.30	Registration
09.00	Welcome
Session One: Value, Classification, Processes	
09.05	Keynote: Strategies and Challenges in Fault Seal Russel Davies, <i>RDR/Schlum</i>
09.45	Invited Speaker: Fault Seal analysis techniques and current industry problems Scott Wilkins, <i>Anadarko</i>
10.15	New insights into fault rock forming processes & exceptions to commonly applied fault seal methodology Robert Worthington, <i>Statoil</i>
10.35	Break
11.00	Invited Speaker: Fault Fictions: how do mental models of faults condition the utility of predictions? Zoe Shipton, <i>University of Strathclyde</i>
11.30	Revisiting fault geometry and architecture Anita Torabi, <i>Uni Research CIPR, Bergen, Norway</i>
11.50	3D Characterisation of microstructures & porosity in damage zones of siliclastic rocks Hannah Riegel, <i>Univ Camerino</i>
12.10	Efficient Handling of fault properties using the juxtaposition table method Tors Anders Knai, <i>Statoil</i>
12.30	Lunch
Session Two: Carbonates	
13.30	Invited Speaker: Predicting sealing/baffling in faulted carbonates John Solum, <i>Shell</i>
14.00	Impact of Faults on Fluid Flow in Carbonates Emma Michie, <i>Badleys</i>
14.20	Architecture & Permeability of fault zones in tight carbonates Antonino Cilona, <i>Shell</i>
14.40	Break
Session Three: Lab & Geomechanics 1	
15.10	Keynote: Geomechanics & Microstructure of Faults: an experimental perspective David Dewhurst, <i>CSIRO</i>
15.40	Recent advances in lab measurements of flow properties of fault rocks Quentin Fisher, <i>University of Leeds</i>
16.00	Pore-Scale Imaging of Cross Fault Flow in High Porosity Sandstones using High pressure-T Fluid Tomography Thomas Seers, <i>Texas A&M</i>
16.20	Variation of uniaxial compressive strength in different architectural elements of fault zones. Cayo César Cortez Pontes, <i>University of Campino</i>
16.40	Finish Wine Reception

Day Two	
08.30	Registration
Session Four: Lab & Geomechanics 2	
09.00	Invited Speaker: Fault permeability evolution with clay smears in hybrid failure – insights from analogue models and flow simulations <i>Michael Kettermann, RWTH Aachen University</i>
09.30	Comparative influence of normal and shear stresses on the hydraulic conductivity of thin cracks in a tight quartz sandstone, a granite and a shale <i>Ernest Rutter, University of Manchester</i>
09.50	Methodology for improved prediction of fault properties using data from the CO2CRC Otway CCS Project <i>Eric Tenthorey, CO2/GRC Geosc Aus</i>
10.10	Adding probability to the prediction of fracture stability by quantifying the influence of in-situ stress, cohesion & friction angle <i>Sarah Weihmann, University of Aberdeen</i>
10.40	Break
Session Five: Integrated Outcrop 1	
11.00	Keynote: Internal Structure of fault zones and its impact on fault seal Conrad Childs, UCD
11.30	Evaluating & improving fault seal workflows using outcrop analogues <i>Yannick Kremmer, University of Strathclyde</i>
11.50	Implications of cataclasis for fluid flow across normal faults in a weakly lithified multilayer <i>Andy Nichol, University of Canterbury</i>
12.10	Lunch
Session Six: Integrated Outcrop 2	
13.10	Invited Speaker: Fault Zone Deformation & Fluid History in mechanically layered mudstone & chalk <i>David Ferrill, SRI San Antonio</i>
13.40	3D Anatomy of a composite shale smear: along strike variations of fault zone architecture & deformation mechanisms of normal faults in poorly lithified sediments (Miri, Malaysia) <i>Silvia Sosio de Rosa, University of Strathclyde</i>
14.00	Fault injectites: Implications for fluid flow along and across faults <i>Dave Healy, University of Aberdeen</i>
14.20	Shale Smear Continuity in a poorly lithified turbidite; implications for fault seal potential <i>Gabrielle Watson, University of Canterbury</i>
14.40	Break
Session Seven: Modelling	
15.20	Reservoir modelling strategies for intra-reservoir faulting <i>Simon Oldfield, University of Leeds</i>
15.40	Stochastic Modelling of Fault Zone Permeability: Implications for Seal Analysis <i>Neil Grant, Conoco Phillips</i>
16.00	Representation of small-scale fault displacement partitioning in reservoir modelling <i>T. Manzocchi, UCD</i>
16.20	The Impact of deformation bands in fault zones on permeability; an upscaling approach <i>Hayley Vosper, BGS</i>
16.40	Discussion

17.15	Finish Wine Reception
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Day Three	
08.30	Registration
	Session Eight: Exploration & Production 1
09.00	Keynote: Stochastic Trap analysis comparison of juxtaposition & SGR algoirhms. A global Review Titus Murray, <i>Fault Seal Ltd</i>
09.30	Using Trap Analysis to derive prospect-fill scenarios in fault-bounded traps: A Case Study from the Southern North Sea Pete Bretan, <i>Badleys</i>
09.50	The Application of existing fault-seal algorithms to fields in the greater Baram Delta, NW Borneo Arjan Brem, <i>Shell</i>
10.10	Modelling Shale Smear and its inclusion in Fault Seal Analysis Neil Grant, <i>Conoco Phillips</i>
10.30	Break
	Session Nine: Exploration & Production 2
11.05	Invited Speaker: Smears, holes, SGR, and fault seal prediction Graham Yielding, <i>Badleys</i>
11.35	Application of temporal fault seal analysis Cathal Reilly, <i>Midland Valley</i>
11.55	Evaluating risk of depletion of an Exploration Prospect from a neighbouring field and its impact on potential future drilling Kamanasish Dutta, <i>DONG Energy</i>
12.15	Lunch
	Session Ten: Exploration & Production 3
13.15	Keynote: A decade of progress and regress in flow simulation of faulted reservoirs Steve Davis, <i>ExxonMobil</i>
13.45	Permeability of faults in shale rich sequences: evaluating the risk of upwards leaking along faults of fracking fluids Yannick Kremmer, <i>University of Strathclyde</i>
14.05	High Resolution Borehole-Imaging of Faults Architecture and Scaling in Carbonate and Siliciclastic Shales, Saudi Arabia Mohammed Ameen, <i>Aramco</i>
14.25	Data sampling and the accuracy of fault models based on T/D and T/Z data Tiago Alves, <i>University of Cardiff</i>
14.45	Discussion
15.05	Closing Remarks
15.40	End of conference

POSTER PROGRAMME

<p>Predicting properties of faults in sand-shale sequences: case studies from the Rotliegend, Dutch Southern North Sea area A. Silvius, <i>EBN</i></p>
<p>Quantifying the effect of core plug edge effects on porosity and permeability under uniaxial and triaxial loading conditions Sophie Harland, <i>University of Aberdeen</i></p>
<p>Variations in porosity values by gas permeoporosimeter and digital methods in rocks affected by deformation bands. Cayo César Cortez Pontes, <i>Federal University of Campina Grande</i></p>
<p>Exploring the influence of fracture pattern attributes on fluid flow in a fractured reservoir analogue Dave healey, <i>University of Aberdeen</i></p>

Oral Presentation Abstracts (Presentation order)

Wednesday 15th November 2017
Session One: Value, Classification,
Processes

KEYNOTE: Strategies and Challenges in Fault Seal

Russell Davies, Rob Knipe, Alton Brown, Henry Lickorish, Steve Freeman, Simon Harris, Paul Wilson, Stewart Smith, Danny Povey, Graham Phillips, Anren Li

Fault seal studies have played a key part in oil and gas trap analysis since as early as the mid 1960's as evidenced from work published by Smith (1966) on the theory to differentiate sealing from non-sealing faults building on the seminal work on capillary trap seal of Hubbert (1953). These early studies identified that cross-fault control is not determined solely by rock type but by the capillary properties controlled by small pore throats in clay in siliciclastics. Smith recognized fault seal controls by both cross-fault juxtaposition and fault rock seal, which have been a foundation to fault seal analysis over the last 60 years. A fault seals as long as the sealing capacity is not exceeded across the fault rock or the lithofacies juxtaposed across the fault. Once the capillary seal is exceeded the rate of flow across the fault is controlled by the effective permeability of the fault rock or the juxtaposed lithofacies. The capillary control and permeability define the fundamental physics of cross-fault flow resistance.

Over the intervening years we have measured calibrated, characterized, and modeled these properties in the subsurface with varying degrees of success. Defining rock properties has been our major uncertainty. The capillary processes are required to estimate the columns of hydrocarbons supported across the faults in exploration and the flow rates controlled by the effective permeability in reservoir simulation and modeling. The type of fault rock, their properties and distribution have a high degree of uncertainty, which has only more recently been considered in the analysis.

Algorithms such as shale gouge ratio and clay smear factor for estimating clay content have been a primary concern, but these are essentially geometric approaches with questions about clay types and mechanical behavior more difficult to assess and incorporate into the analysis. Too often the properties of the cross-fault lithology juxtaposition are ignored or limited to an assignment as either sand-sand or sand-seal juxtaposition windows. Fault seal in carbonates is also not well understood where standard algorithms developed in siliciclastic reservoirs are more difficult to apply. The fault zone architecture including damage zones can also play a role in the flow but incorporating these characteristics usually requires data on a scale not resolvable in the subsurface. Estimating the mechanical properties of the layers at the time of deformation may provide an index to complexity that provides a calibration to the flow but the uncertainties are high and impact not well understood.

Modeling the fault rock distributions, stratigraphic variability, and fault zone architecture with calibrated capillary threshold pressures and effective permeability from laboratory or in situ measurements is the standard approach for characterizing the flow resistance in exploration and development. The controls on the flow, however, are also impacted by pressure differences in compartments, the relative permeability of the fault rocks and their changes with production as well as other often poorly resolved geological factors. In exploration trap analysis our goal is to understand the control on the hydrocarbon column. If faults are expected to be a primary seal, then the principal question is the evidence that supports the fault seal. Fault seal is a high risk as the expected behavior is more likely to leak than seal. Each fault study is unique, however, and the challenge for the interpreter is understanding the uncertainty in the input. Too often we rely on standard methods without adequately considering the range of uncertainties that influence fault behavior in exploration and development.



NOTES:

Invited Speaker: Fault Seal Analysis Techniques & Current Industry Problems

Scott J. Wilkins

Anadarko Petroleum Co. The Woodlands, TX. 77380

Fault seal analysis techniques rely on many approaches that were developed 20-30 years ago, with minor modifications since then. As all fault seal analyses rely on an accurate structural and stratigraphic model, viable interpretation is essential, including consideration of associated uncertainty. Fundamentally different questions arise during exploration and production phases of hydrocarbons extraction. In this contribution I will review common techniques employed during fault seal analysis in both exploration and production phases, illustrating both successful and unsuccessful approaches, and areas that require development of improved analysis techniques.

During exploration the primary goal is to estimate the hydrocarbon column height that faults are capable of trapping (i.e., fault seal capacity). Different approaches are typically employed when evaluating the fault seal capacity. A simple analysis of fault-juxtaposed stratigraphy (often determined from 1D logs, combined with 3D correlated seismic horizons) is useful as a first pass to identify possible leak points where permeable reservoirs are juxtaposed, although such analyses ignore the sealing properties, or more specifically, the capillary displacement pressure of fault rock to non-wetting hydrocarbons. Because core and outcrop exposures, supported by laboratory experiments, indicate fault rock properties are significantly different from undeformed surrounding rocks, most seal analyses includes a component of fault rock property estimation built upon the juxtaposition framework. Various fault rock property algorithms are typically employed at this stage, including averaging techniques that attempt to estimate the amount of shale entrained within the fault zone (i.e., "mixing" algorithms such as Shale Gouge Ratio) or continuity techniques that seek to determine the spatial distribution and/or thickness of ductile, low-permeability mudrocks smeared along the fault (e.g., clay smear potential or shale smear factor). Quantitative correlations between fault rock property estimates and capillary displacement pressures are then used to estimate hydrocarbon column heights for various fluid types, and compared with trap reliefs and leak points to estimate trapped hydrocarbon volumes. These techniques typically assume adequate hydrocarbon charge capacity. An alternative and increasingly common approach for evaluating fault seal capacity relies on an evaluation of the stress resolved along the fault as an indication of the tendency for faults to slip or become "reactivate". The basic tenant of this approach is that reactivation enhances the permeability of a fault zone and increases the likelihood for leakage, but quantitative estimates of leakage remains mostly untreated.

Most of these approaches are commonly employed in present day conditions (i.e., observed fault and juxtaposition geometries and present-day in-situ stress) without consideration of paleo-seal behavior that becomes important for older petroleum systems. Another extremely important topic for exploration concerns fault behavior during fluid migration from source rock intervals. However, there is little attention devoted to this topic in literature, and significant room for improvement exists in this category of fault analysis.

Fault transmissibility is the key question that arises during development and production of faulted traps. If fault transmissibility is low enough in densely faulted structures, the field may be compartmentalized enough that the amount of wells required deem the field uneconomic. A fault transmissibility evaluation includes many of the steps outlined for the exploration phase, although instead of evaluating seal capacity in terms of capillary displacement pressure, the key parameters are fault permeability, fault rock thickness, and contrast in permeability with surrounding undeformed reservoir rocks.

And finally, all of these methods rely to some degree on the resolution of data upon which interpretations are derived. As such, the omission of sub-seismic structures, such as intact relays or dense arrays of deformation bands, may have profound effects on how we approach fault seal analyses during both exploration and development.



NOTES:

New insights into fault rock forming processes and exceptions to commonly applied fault seal methodology

Robert Worthington¹ & Quentin Fisher²

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²Institute of Applied Geoscience, University of Leeds, Leeds, LS2 9JT, UK.

Two key processes are commonly considered when predicting the sealing behaviour of low-clay content (<ca.15%) fault rocks within siliclastic reservoirs. These are cataclasis (grain crushing) and any subsequent meso-diagenetic quartz cementation. Lacking local core observations this information can be interpreted from seismic constraints (i.e. latest fault timing and estimated depth of deformation) and an understanding of burial/temperature history. These methods may be sufficient to assess fault seal risk within more familiar reservoirs. However, we present a case from less familiar, deep marine reservoir, where fault seal predictions would have been greatly underestimated if it was not for the consideration of two underappreciated and poorly acknowledged sealing mechanisms.

The first is the disaggregation of soft, clay-rich lithoclasts, which together with a minor amount of cataclasis of quartz and feldspar (<20%) has contributed to a reduction in porosity (<ca.5% which is around 30% of the host rock porosity, Figure 1a). The pore space between the larger grain fragments within the fault rock is filled with small grain fragments produced by cataclasis as well as clays that comprised the soft lithoclasts (Figure 1b). Although these fine-grained fragments comprise only around 10 to 20% of the fault rock volume their presence along with the fine-grained clays has proved very effective at reducing permeability. Closer inspection of the clays revealed a delicate texture containing large amounts of microporosity that is extremely good at blocking pore throats within the fault rock (Figure 2). Further analyses of these clays indicate a mixture of illite and chlorite. Although these clays are present only in small volumes (ca.5% of the host rock) their unique texture appears to have had a significant impact on flow properties. Of course, the presence of these clays need not be exclusive to the disaggregation of soft lithoclasts and for this reason the recognition of clay type forms the second sealing mechanism that will be discussed in this presentation. Our observations indicate that even in small volumes, clays with such textures, that form part of a cataclastic matrix with only minor grain size reduction, are likely to significantly impact flow.

The observations on fault rock forming processes presented here derive from multiple fields and wells within a well-known, deep marine reservoir in production with high in-place-volumes. Implications are clear in that even where fault rock clay content predictions are low (e.g. <ca.15% SGR) and where the timing of faulting indicates an absence of significant cataclasis (i.e. shallow depth of deformation) faults can act as effective baffles and may even account for differences in pressure and oil column heights. Stressed permeability measurements for these fault rocks provided values up to about 3 orders of magnitude lower than those of the undeformed reservoir. Such permeability contrasts may not have a major impact on single-phase flow. However, effective oil permeabilities (absolute vs relative permeability) of these fault rocks are up to about 5 orders of magnitude lower than those of the undeformed reservoir. Estimates on capillary membrane sealing capacities (Hg-air injection, un-stressed) indicate the potential for ca. 50-80m oil column heights. The results of this work are extremely useful to further our understanding of compartmentalisation within this reservoir and how we risk future drilling targets. Prior fault seal predictions which had lacked such detailed core analysis work and a consideration of the fault sealing mechanisms outlined in this presentation, expected sealing only where faults have a large throw or where fault rock clay content is high. This recent work has however shown us the importance of low throw and subseismic scale faults. An appreciation that we hope can be incorporated within our structural seismic interpretation, reservoir modelling and flow simulation practice.

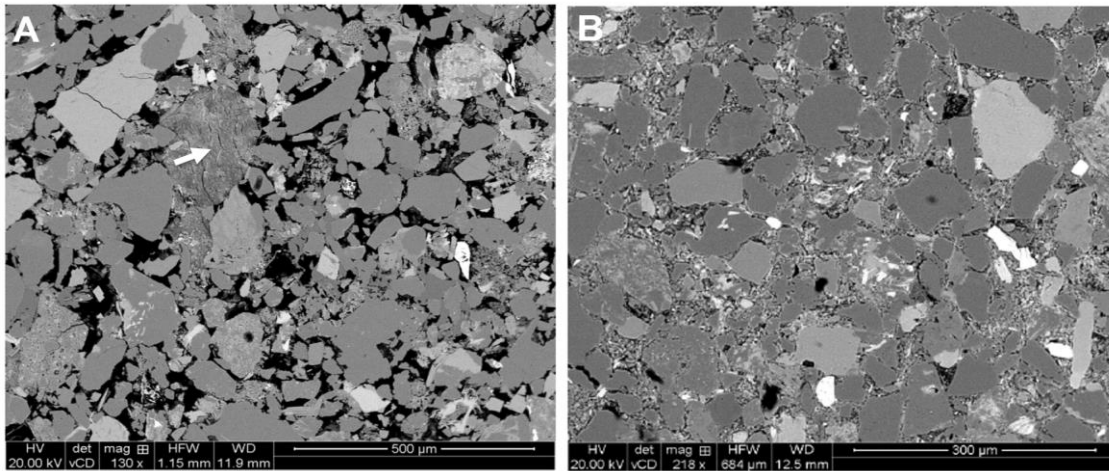


Figure 1. (A) BSEM image showing the undeformed reservoir rock within sample STAT2.1. (B) BSEM image showing the fault rock within sample STAT2.1. Note that the pore space between the large grains has been filled with grain fragments produced by cataclasis (both quartz and K-feldspar are present) as well as fine grained clay produced by the disaggregation of soft lithoclasts.

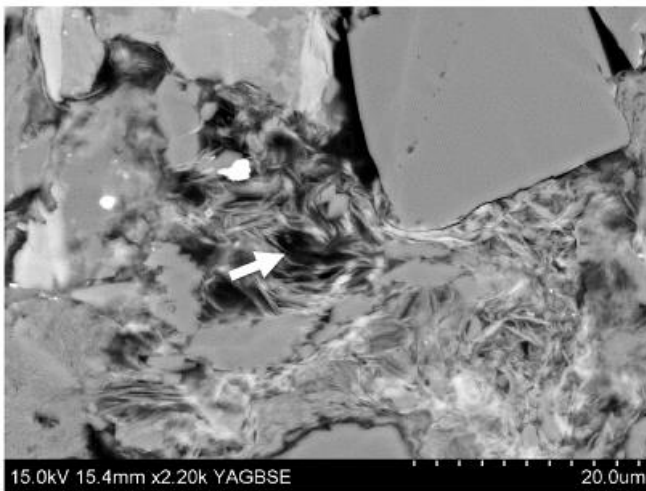


Figure 2. Ion beam polished BSEM image showing the very delicate clay texture (see arrow) containing large amounts of microporosity within the fault rock in sample STAT2.1.



NOTES:

Invited Speaker: Fault Fictions: how do mental models of faults condition the utility of predictions?

Z.K. Shipton, J.J. Roberts, Y. Kremer, R.J. Lunn and J. S. Caine

Geologists are tiny creatures living on the 2-and-a-bit-D surface of a sphere who observe vanishingly small and essentially 1D portions (boreholes, roadcuts, streams, beach sections) of complex, 4D tectonic-scale structures on and within the sphere on which they live. Field observations of fault zones are essential to understand fault growth processes and to make predictions of fault zone mechanical and hydraulic properties at depth. Fault zones are composed of many heterogeneously distributed deformation-related elements. Low permeability features include regions of intense grain-size reduction, pressure solution, cementation and shale smears. High permeability elements are open fractures and breccias. The highly variable nature of 1) the architecture of faults and 2) the properties of deformation-related elements, demonstrates that there are complex controls on the physical and chemical evolution of fault zones. There is no simple way of deterministically predicting the bulk hydraulic and mechanical properties of faults.

The aim of many field studies of faults is to provide data to constrain predictions at depth, however, for these data to be robust, data from multiple sites are required. Our ability to combine datasets from multiple studies is hampered by variability in the usage of fault terminologies. This occurs, at least in part, due to variations in what psychologists call the mental models held by individual field geologists. A mental model is a person's internal representation of an external system, and is the basis for how a conceptual or numerical model of a system is defined and parameterised. Mental models are constructed on the basis of a person's experience of the external system, and that experience is by its very nature incomplete and partial when compared to the complexity in the real world. "End-users" such as petroleum reservoir engineers, mining geologists, and seismologists of course have their own mental models of what a fault looks and behaves like. Arguments over the details of terminology baffle the "end users" of fault terminology and can dilute the importance of detailed fault studies and the resulting characterizations of heterogeneities.

Field geologists are comfortable knowing that if you walk along strike or up dip of a fault zone you will find variations in fault rock type, number and orientations of slip surfaces, variation in fracture density, relays, asperities, variable juxtaposition relationships etc. Problems can arise when "end users" of field structural geology try to apply models to general cases without understanding that these are simplified models. For example, when a simplified geological section (like the one in Chester and Logan 1996) gets projected infinitely into the third dimension to define the structure along a fault the size of the San Andreas, or Shale Gouge Ratios are blindly applied to an Allen diagram without recognising that sub-seismic scale relays may provide "hidden" juxtapositions that cause fluids to bypass low permeability fault cores. All too often end users use phrases like "low-permeability fault core and high-permeability damage zone" without fully appreciating complex along-strike relationships, or the likelihood of temporal variation in flow properties.

We argue that the field geology community needs to consider ways to make sure that we educate end-users to consider appropriate and cautious approaches to make best use of the data we provide, and gain an appreciation of the uncertainties inherent in our limited ability to characterize 4D, tectonic structures, at the same time as understanding the value of carefully collected field data.



NOTES:

Revisiting fault geometry and architecture

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Fault plane geometry, fault zone architecture (fault core and damage zone), and its properties are important factors in characterization of a reservoir and predicting fluid flow. Conventional methods such as SGR, clay smear and transmissibility multipliers (e.g. Fisher and Knipe, 1998; Manzocchi et al., 1999; Yielding, 2012) have been used for fault seal analysis, but the uncertainty in input parameters (such as fault geometry and properties) limits the accuracy of predictions (Ottesen et al., 2005).

Geological models for single faults assume simple geometric shapes such as circular and elliptical shapes with maximum displacement at the fault center, oversimplifying the fault 3D structure. There is uncertainty in defining fault plane (main slip surface) geometry (displacement, length, height, segmentation); as well as in the definition and dimensions of fault zone architecture. These uncertainties are partly related to the inconsistency in definitions by geologists and partly due to the methodological constraints, utilizing mostly biased data (1D or 2D data/ maps from 3D data) that are not fully representative of the fault 3D structure.

Utilizing fault seismic attributes (Torabi et al., 2016; Libak et al., 2017) and integrating them with data and knowledge from outcrops, we revisit the fault 3D structure and provide the details of fault plane internal structure and fault zone architecture. Our results show that an isolated fault plane can include many internal fault segment traces that interact and affect the fault length and displacement distribution (Fig. 1). The depths to the maximum displacement and length of faults can be significantly different and depend on the fault internal complexity. This will in turn affect the scaling relation between fault maximum displacement and length, resulting in a power-law relation rather than a linear relation (Torabi et al., 2016). Furthermore, our results reveal that the fault maximum displacement for an isolated fault is not necessarily located at the fault center as it is usually considered (e.g. Barnett et al., 1987; Nicol et al., 1996). The new findings motivate us to revisit the current fault geometric models and to raise a fundamental question as to where the fault center is actually located in a 3D fault structure.

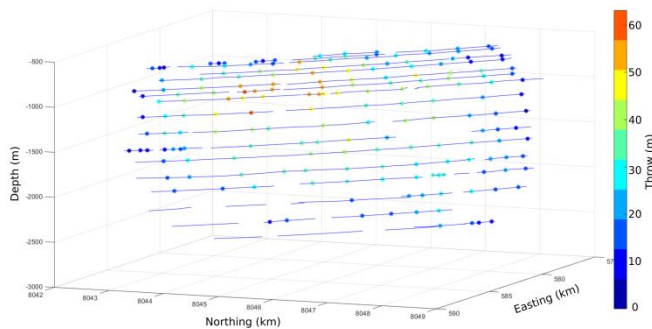


Figure 1. Blue lines present fault segment traces extracted from seismic attributes. Circles illustrate where the displacement measurements were conducted on seismic data along the segment traces. The colour bar indicates the displacement (throw) values.

Acknowledgement: Authors acknowledge support from Petromaks2 and NORRUSS programs at Norwegian Research Council (project 243628) and Russian Foundation for Basic Research (project 15-55-20004).



NOTES:

Three-dimensional characterization of microstructures and porosity in damage zones of siliciclastic rocks

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⁴ ENGIE Group, France

Faults in siliciclastic rocks are characterized by great variability of fault zone architecture and relative permeability properties. This is because siliciclastic rocks (i.e. turbidite successions) are commonly represented by alternating layers of various thickness and grain size, forming successions with contrasting mechanical properties. For example, the alternation of sandstone and mudstone layers is responsible for the simultaneous occurrence of brittle and ductile deformation. When a fault is present, the alternation of layers produces corresponding alternating fault cores, which influences the hydraulic behavior of the fault zone. By using the X-ray mCT microtomography images, we are able to give a quantitative analysis and characterize the micro-structural properties (i.e. grain/pore shape, size, roughness and connectivity) of rocks within the varying siliciclastic damage zones. The three dimensional pore network of a given rock takes into account porosity, pore connectivity, and specific surface area. When analysing samples from damage zones, these attributes can be used to determine the hydraulic properties of the rock, in relation to the surrounding, undamaged host rock. In the case of the damage zone, it is generally characterized by means of the fracture analysis and modelling implementing different approaches, for instance the discrete fracture network model, the continuum model, and the channel network model (Neuman, 2005). Conversely, the fault core is more difficult to characterize because it is normally composed of fine grain material generated by friction and wear (Aydin, 2000). The control exerted by the structural fabric on the hydraulic behavior of damage zones is well evidenced in high permeability anisotropy in the fault core.

The siliciclastic samples are taken from heavily faulted and fractured well-cemented sand and mudstones successions. These characteristics allow for observation of porosity, permeability, and fluid flow within the rocks. We can analyze the architecture of these fault and assess the factors (i.e. fault zone permeability) that determine whether or not the fault acts as a barrier or conduit. These results will be useful for understanding the deformation process and hydraulic properties depending on fault zones across meter-scale damage zones.



NOTES:

Efficient handling of fault properties using the Juxtaposition Table Method

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The Juxtaposition Table Method is a new technique that allows all known factors contributing to the fault rock properties to be accounted for in reservoir modelling and during matching to real reservoir behaviour. As observations of faults in nature show a rapid and unpredictable change in fault rock content and architecture, fault representation in reservoir models will necessarily be a simplification of the real fault structure and complexity. Therefore, it is important that the uncertainty range is captured in the input parameters, and the history matching is done using a method available to both geologists and reservoir engineers. The Juxtaposition Table Method provides a common interface that is easy to relate to for all petroleum technology disciplines, and it efficiently handles the probability distribution of the input parameters (Figure 2).

Traditional methods for fault rock type prediction and fault property distribution are based on Shale Gouge Ratio (SGR) and an established SGR - permeability relationship. The SGR algorithm assumes homogeneous mixing, while fault rocks are in reality created by a combination of shearing, mixing, reorientation, grain breakage and diagenetic alteration. A limitation to SGR based methods is that they predict similar fault rock type for juxtapositions with similar SGR, i.e. the same permeability value will be assigned regardless of any variations in deformation mechanisms related to differences in age and burial depth of the sediment at the time of faulting. Thin section analysis of fault rocks from different stratigraphic positions at faults that were active after reservoir deposition, has shown that cataclasites were developed at the deeper part of the fault at the same time as disaggregation zones were developed at shallower burial depths.

The fact that each reservoir zone juxtaposition has its own individual position in the Juxtaposition Table Method (Figure 2) represents a significant advantage compared to other methods.

Firstly, the fault rock permeability can be assigned to reservoir zone juxtapositions without being limited to one SGR - permeability curve. This allows for including conceptual knowledge regarding the deformation mechanisms that acted at different stratigraphic levels and the nature of the clay-sandstone mixing when the rock was deformed (i.e. homogeneous mixing or increased weighting of the nearby reservoir zones).

Clay smear modelling can be based on a conceptual understanding of source layers, which often would not be represented as individual reservoir zones in the simulation grid. Clay smears can be modelled in two principally different ways, either by probabilistic modelling of explicit smears (transmissibility=0), or by reducing the fault rock permeability for juxtapositions with clay smear present.

Further, all conceptual understanding of how the fault core thickness varies with the mechanical stratigraphy can be incorporated.

Finally, the fault properties can be efficiently tuned as new knowledge is gained during history matching of dynamic models. There is full flexibility for adjusting the values of individual juxtapositions within the context of the established fault permeability model and uncertainty range. This is particularly useful in assisted history matching. As the Juxtaposition Table Method is grid independent, the learning from history matching can be carried over to new vintages of reservoir models.

An important innovation is that the Juxtaposition Table Method extracts fault rock permeability from the table, while other methods calculate SGR by extracting the clay/phyllsilicate fraction from the 3D grid and apply an established SGR - permeability relationship. This is a strength rather than a limitation, as it allows for better control of input parameters without any significant geological information being lost.

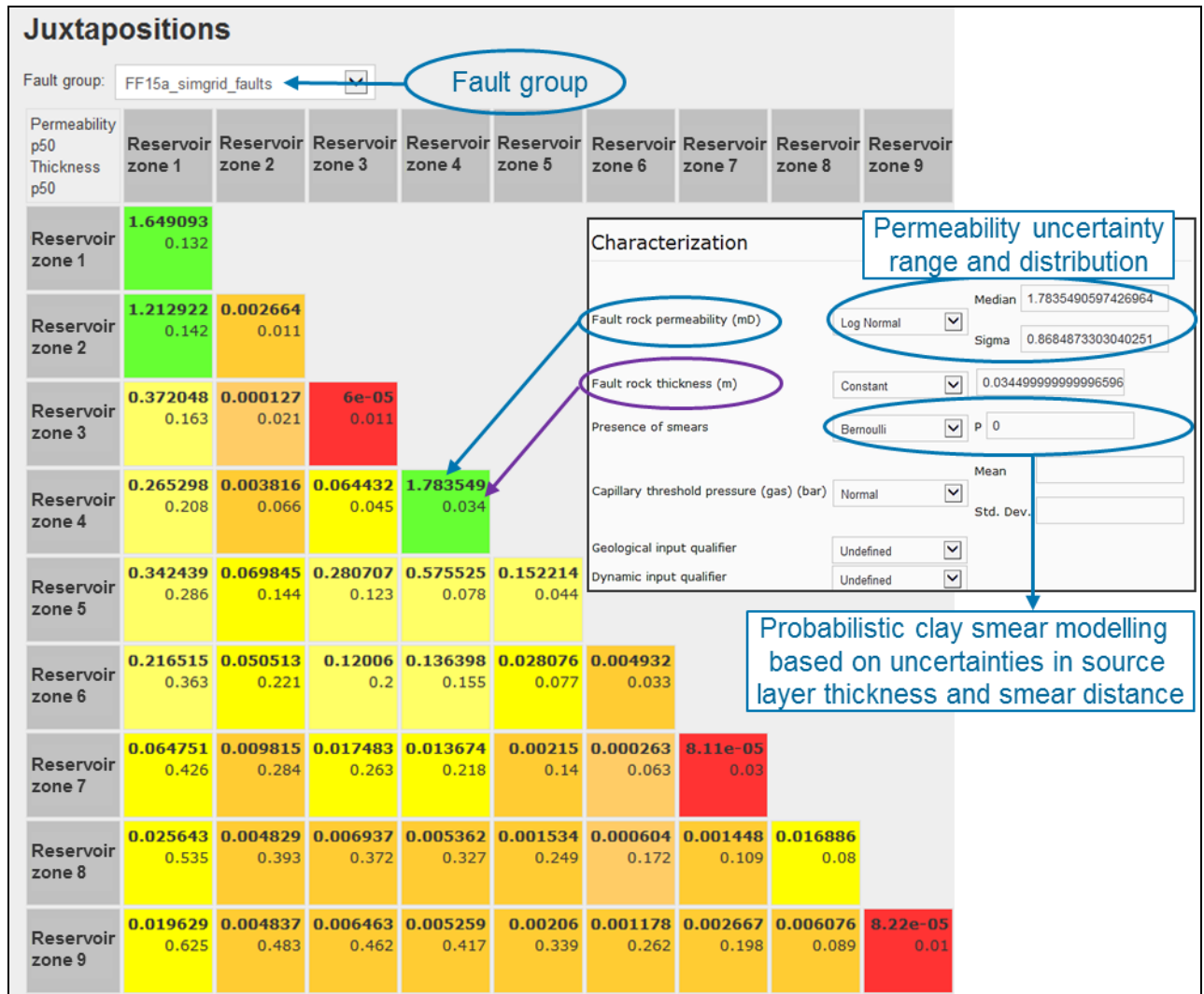


Figure 2. The Juxtaposition Table Method; a table of all possible juxtapositions of reservoir zones with assigned values for fault rock permeability including probability distribution and fault rock thickness defined as a constant or as a ratio of the fault throw.



NOTES:

Wednesday 15th November 2017
Session Two: Carbonates

Invited Speaker: Predicting sealing/baffling in faulted carbonates

John Solum

Shell

Fault dependent column heights and intra-reservoir fault compartments occur worldwide. The lack of rules to predict sealing/baffling in faulted carbonates makes it difficult to accurately risk fault-defined carbonate prospects (is a fault likely to increase the size of a trap by supporting a hydrocarbon column?) or to identify infill drilling targets in more mature carbonate fields (is a fault likely to have a permeability that is sufficiently low to prevent a fault block from being drained by an existing well?).

Documenting the effects of faults on flow on a production time scale (very roughly less than 20-50 years) is the first step to developing general rules to predict the behavior of faults in carbonates. Cross-fault differences in water table elevations or pressures and sealing behavior inferred from well tests or from history-matching exercises show that faults in carbonates are capable of sealing on a production time scale. Moreover, observed permeabilities of faults in carbonates are sufficiently low that the time needed for re-equilibration of production-induced cross-fault pressure differences can easily exceed 20 years and can reach a near geological time scale (100,000 years +). The capability of some faults in carbonates to seal on a geological time scale is indicated by examples of carbonate reservoirs with cross-fault column height differences that are not due to variations in reservoir or fluid properties, hydrodynamic tilting, or post charge deformation.

The development of models to predict static or dynamic fault seal in carbonates will be more difficult than in clastics as seal can be due to a larger variety of mechanisms (diagenetic alteration, cementation, mechanical incorporation of sealing non-carbonate lithologies, cataclasis, etc.). Further, in addition for seal potential to exist, a continuous layer of fault rock/fault core material will also be needed, and the conditions needed for such a layer to develop are likely to vary with geologic setting, lithology, and displacement. A successful model of fault seal potential in carbonates will likely require combining predictions of fault rock continuity with a number of mechanism-specific probabilistic column height distributions.



NOTES:

Impact of faults on fluid flow in carbonates

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Faults have been shown to exert significant control on fluid flow within the subsurface. Research determining the conditions in which faults act as conduits, barriers or partial barriers to flow in siliciclastic reservoirs has been widely documented. This understanding can help to reduce uncertainty when estimating the hydraulic properties of fault zones in the subsurface. However, limited research has been undertaken on the impact of faults on fluid flow in carbonate reservoirs despite their importance in global hydrocarbon reserves; around 60% of global oil reserves and 40% of global gas reserves are stored in carbonates. To assess across-fault flow potential, and consequent reservoir compartmentalisation, the distribution and petrophysical properties of fault rock within a fault zone must be determined. Accordingly, this research works towards a predictive method to estimate fault rock generation in carbonate rocks based upon key lithological and fault parameters. To this goal, samples of faulted carbonates with a variety of carbonate lithofacies, diagenetic histories, fault kinematics and fault displacements have been studied from both outcrop and core. Localities of examined faulted carbonates include: Malta, Italy, Oman, Abu Dhabi and Germany. Fault zone mapping is used to assess the continuity of fault rocks and how their spatial distribution can be controlled by displacement, fault zone architecture and structural irregularities along fault-strike. The deformation mechanisms that form such fault rock fabrics are determined using microstructural analyses. Combining this knowledge with petrophysical properties measured in the lab, trends can be observed showing the impact of carbonate lithotype, juxtaposition and fault displacement on fault rock production, and hence the consequent across-fault fluid flow potential. These trends are used to predict the transmissibility multipliers that should be used within a geocellular model of a carbonate reservoir. Further to this, the fault rock permeability and transmissibility can be calculated on triangular juxtaposition diagrams, allowing for a quick 2D analysis of carbonate fault seal. Understanding the controls on deformation style during faulting of carbonate sequences aids prediction of the types of fault rock formed, their hydraulic properties and influence during reservoir simulation.



NOTES:

Architecture and permeability of fault zones in tight carbonates

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Predicting whether a fault enhances (conduit) or reduces (baffle, seal) reservoir properties can be the difference between a discovery and a dry hole. While rules for predicting both static and dynamic fault seal potential are well-established for clastics, similar rules are lacking for carbonates. In carbonates, the fault architecture, distribution of different types of fault rocks (e.g., breccias, cataclasites), and the interplay between deformation and diagenesis must be considered to predict the seal vs. conduit behavior of a fault zone.

Characterizing the architecture of fault zones in subsurface is extremely challenging, thus outcrop analog studies represent a valuable resource. We present the results of an integrated study (i.e., structure, diagenesis, and petrophysics) of two carbonate outcrop analogs in central Italy, where faults are known to act as dynamic seals at depth causing approximately 100m of hydraulic head drop in an aquifer with both porosity and permeability depending on fractures and karst features (Celico *et al.*, 2005).

The internal architecture of these faults is very well-exposed, thus allowing for detailed mapping of the along-strike distribution and continuity of fault cores and associated fault rocks. The fault rock bodies (cataclasite and breccia), which are 10s of meters wide, have been extensively sampled. More than 150 samples, comprising several fault architectural elements and carbonate host rocks, were collected in transects orthogonal to the fault zones. Fault rock petrophysical properties were measured on 1-inch plugs and then linked to characteristic microstructures and fault rock textures.

We consistently documented increasing comminution and decreasing pore size from the outer toward the inner portions of fault cores (Fig. 1). Three types of breccias (crackle, mosaic and chaotic) and various types of cataclasites (proto- to ultra-cataclasites) were identified. For each architectural element, permeability ranges (not including large fractures) were measured (Fig. 1). Crackle breccias reach the highest permeability (up to 100s of mD), whereas the ultra-cataclasites have the lowest permeability (down to 0.01 mD, which is roughly equivalent to unfractured host rock). Breccias have heterogeneous pore networks and low capillary entry pressures (<10 psi), cataclasites display very narrow pore throat distributions and high capillary entry pressures (up to 15000 psi).

Fault zone architecture and properties vary in 3D as functions of lithology and displacement. These outcrop observations are combined with literature-sourced statistics on fault architecture and displacement to construct rules for predicting the presence of conductive vs. potentially sealing fault rocks. Along-strike variations of displacement result in a varying sealing potential along the fault: below a displacement of approximately 200 m fault cores commonly contain only permeability-enhancing breccias. Above that value they can contain cataclasite in addition to breccias, and therefore have a higher probability of sealing.

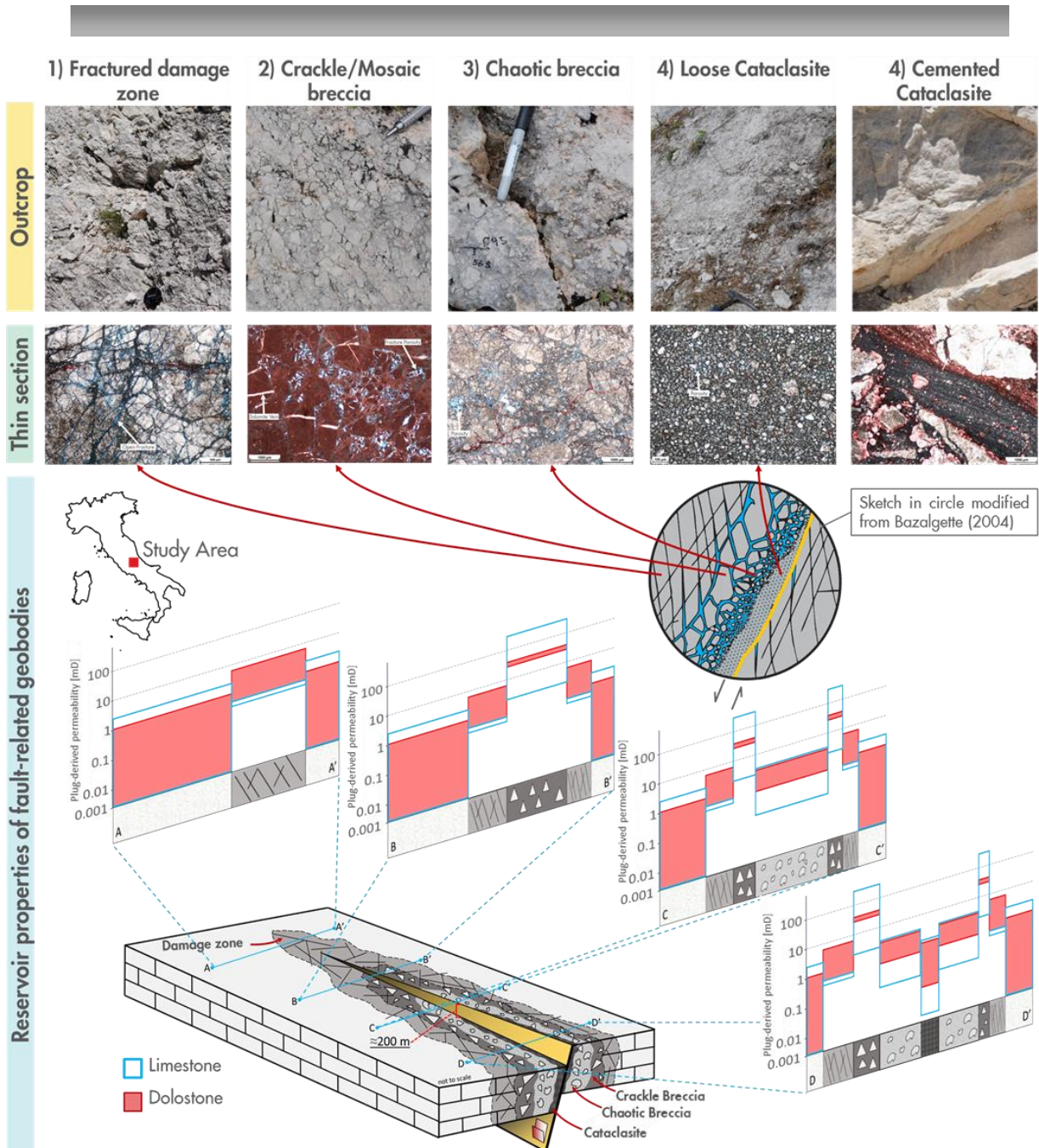


Figure 1. Along-fault distribution of fault rocks, and their ranges of permeability. Overview of outcrop images (first row), microstructures (second row), and permeability ranges (not including large fractures) in limestones and dolostones (third row).



NOTES:

Wednesday 15th November 2017
Session Three: Lab & Geomechanics1

KEYNOTE: Geomechanics and Microstructure of Faults: An Experimental Perspective

David N. Dewhurst¹, Silvio Giger, Bozkurt Ciftci, Ausama Giwelli, Claudio Delle Piane, Jeremie Dautriat and Ben Clennell

¹CSIRO

Geomechanics and microstructure of faults are intimately linked due to both physical and chemical processes which can have a significant effect on rock strength and flow properties. This presentation summarises the controls on fault rock strength, shale smear continuity in siliciclastic rocks, fault transmissibility in carbonates and the links between microfabric and permeability anisotropy development in sheared clays. These conclusions have been reached through the use of multiple geomechanical and microstructural techniques, including triaxial, ring shear and direct shear box testing supplemented by optical and electron microscopy and measurements of petrophysical properties such as porosity and permeability.

Examples using such approaches are used to highlight how kinematic and diagenetic histories control rock strength. Cementation is shown to generate stronger fault rocks, but continued reactivation indicates that the cementation results in a competency contrast which promotes failure along the boundary of the cemented fault zone and reservoir rock. In contrast, alteration of load bearing feldspars to kaolinite resulted in reservoir and fault rocks having similar geomechanical properties but friction coefficients for a granular rock are low as a result of the alteration of the rock load bearing framework.

Direct shear tests were used to evaluate fault zone development and clay smearing in siliciclastic rocks. A large shear box was used and variables tested included displacement (up to 10x clay layer thickness), bedding dip, plus sand and clay properties (porosity, water content and consolidation state) with fluid flow across the clay being measured. The breakdown of the clay seal was linked to its clay content while the smear continuity was related to increased effective normal stress during shearing but not to the stiffness or ductility of the clay layer. The formation of clay smears was governed by brittle processes (segmentation, abrasion and grain crushing), rather than by drag, plasticity or clay injection. Seal breach by fluids was not always achieved even in the case of discontinuous smears due to abrasion and grain crushing of the reservoir sand.

The direct shear behaviour of carbonates was also investigated, testing porous, vuggy travertine samples. Tests were performed in both static and dynamic mode, monitoring fluid flow both during and after deformation stages. The mechanical behaviour of the travertine was similar for slip between 20-120 mm, with low strains dominated by fracturing and high strain by gouge development. Irrespective of the effective stress level, dynamic fault transmissibility decreased for all samples. Cylindrical core plugs were taken across the developed fault zones to reactivate them in triaxial tests. Frictional hardening was noted in these tests while permeability continued to decrease due to further development of fault gouge. Once gouge develops, transmissibility is permanently decreased and reactivation has no impact. Finally, deformation to very high strains can be achieved using ring shear devices. A sealed ring shear permeameter was used to deform pure clays and remoulded clays. Comparisons of porosity and permeability were made to oedometer tests to simulate the same sediments undergoing one-dimensional compaction. In all cases, shear parallel static permeability was found to be similar to the permeability of one dimensionally consolidated sediments, while shear normal permeability was one to two orders of magnitude lower. Microfabrics observed in optical and scanning electron microscopy showed the development of flattening fabrics, Riedel shears and shear parallel through-going fractures, which were interpreted to obstruct the shear normal flow.

Overall, geomechanical experiments combined with microstructural observations and petrophysical measurements can shed light on meso- to micro-scale fault zone processes and aid us in evaluating more complex situations observed in the subsurface. Accepting that challenges with scaling exist, the intermediate scale of the large shear box experiments starts to provide some data that can be evaluated in terms of larger scale bulk fault seal algorithms as well as enlighten us as to fault zone processes and products with their concomitant effect on rock properties.



NOTES:

Recent advances in the laboratory measurement of the flow properties of fault rocks

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Over the last 30 years the petroleum industry has collected a large amount of data on the microstructure, absolute permeability and mercury injection characteristics of fault rocks. The measurements have been widely used to calculate petroleum column heights and transmissibility multipliers that may be incorporated into production simulation models to take into account the impact that faults have on fluid flow. Unfortunately, many of these measurements were made under inappropriate laboratory conditions such as ambient stress and using brines that were not compatible with the formation fluids. During this time, significant advances have been made in the laboratory analysis of the properties of unconventional reservoirs such as shale resource plays and tight gas sandstones. These advances have been recently applied to the analysis of fault rock samples to provide a more robust understanding of how fault rocks impact fluid flow in the subsurface. This paper will explore some of the key advances and assess the implications for fault seal analysis.

Permeability analysis

Most permeability measurements used by industry were collected using the steady-state method at ambient stress conditions using distilled water as the permeant. The steady-state method used generally meant that permeabilities below around 0.001 mD could not be measured. Measurements are now routinely conducted at in situ stress conditions with a formation compatible brine using the pulse-decay method that can measure permeabilities down to around 10 nD. Measurements can also be made on lower permeability fault rocks using specialized transient techniques that are capable of measuring at the sub-nD level.

Measurements on around 100 fault rocks in clean and impure sandstones (i.e. 0 to 40% clay) indicate that measuring at ambient stress resulted in an overestimation of permeability by a factor of five whereas measuring using distilled water as oppose to formation compatible brines resulted in an underestimation of permeability by a factor of five. In other words, two poor laboratory practices used in the past have partially cancelled each other out. Although it is not recommended that the old laboratory practices are applied when making new measurements, the results do indicate that legacy data collected by industry is still usable.

Recent measurements indicate that clay smears may have permeabilities that are at least two orders of magnitude lower than many previous measurements have indicated.

Relative permeability measurements

Industry has tended to only collect single-phase (i.e. brine or gas) permeability measurements of fault rocks and have neglected to conduct two-phase flow experiments. We have attempted to fill this knowledge gap by conducting gas relative permeability measurements as well as oil-brine relative permeability measurements at a range of wettabilities (i.e. strongly water wet, intermediate/mixed wet and oil wet). These results indicate that applying transmissibility multipliers calculated from single-phase permeabilities can result in an overestimation of fault transmissibilities above the free water level by several orders of magnitude.

Threshold pressure measurements

The petroleum height that fault rocks can seal has often been estimated from mercury injection porosimetry results conducted on unconfined samples. This has two drawbacks. Firstly, the threshold pressure is simply estimated from the shape of the injection curve and therefore is very subjective. Secondly, the only stress applied to the sample is from the mercury itself before it enters the pore space. To overcome these issues, we have built a state-of-the-art mercury injection porosimeter that can inject mercury at up to 55,000 psi while maintaining a net confining pressure of 15,000 psi. The instrument also always an electrical measurement to be made so that the threshold pressure of the sample can accurately measured instead of being inferred from the shape of the injection curve. Results from the new porosimeter indicates that threshold pressure of fault rocks, and hence the petroleum column heights that they can seal, are between 2 and 16 times greater (average 3) than estimated from the traditional unconfined instrument.

Conclusions

Recent advances in the laboratory analysis of fault rocks indicate that:-

- 1) Previous measurements of single-phase fault permeability made under ambient stress and using low salinity brines may still be usable because making measurements at in situ stresses reduces permeability

by an average of five fold but using formation compatible brines increases permeability fivefold (i.e. two wrongs partially make a right). However, new measurements such be made at reservoir conditions.

- 2) Clay smears are likely to have permeabilities that are in excess of two orders of magnitude lower than many previous measurements have suggested.
- 3) Failure to take into account the relative permeability of fault rocks could lead to an overestimation of the transmissibility of faults by several orders of magnitude when two or more immiscible phases are present (i.e. above the free water level).
- 4) The threshold pressure of fault rocks may be at least three times higher than previously estimated based on mercury injection measurements made on unconfined samples.



NOTES:

Pore-Scale Imaging of Cross Fault Flow in High Porosity Sandstones using High Pressure-Temperature Fluid Tomography

Seers, T. D.¹ Andrew, M.² Blunt, M. J.² Bijeljic, B.² Dobson, K. J.³ Hodgetts, D.⁴ Lee, P. D.⁵ Menke, H. P.² and Singh, K.²

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Abstract

Forming ubiquitous features of strain localisation and pore (void) collapse within high porosity sandstone reservoirs and aquifers, the fundamental controls which inhibit or promote the transmission of fluids through small scale cataclastic faults (shear bands) is of considerable interest. In particular, the influence that micro- and macroscopic variations in fault structure imparts over immiscible fluid flow is significant, having direct relevance to activities such as hydrocarbon extraction and the geological storage of carbon dioxide. Previous efforts to characterise the flow properties of shear bands have attempted to draw inference through a combination of microstructural analysis, bulk petrophysical measurements and numerical simulation. Such analyses are incapable of probing the pore-scale controls which govern the transfer of fluids within shear bands, particularly when multiple phases are present.

Here, X-ray micro-tomography is used to image the injection of supercritical carbon dioxide (scCO₂) at reservoir conditions across a single brine saturated shear band (primary drainage), in order to investigate the role that macroscopic and microscopic variability in fault structure plays in fluid entrapment. Analysis of the discrete pore fluid displacement events within the portion of the sample upstream of the fault reveals that elevated phase pressure in the pooling scCO₂ enhances non-wetting contact with the pore wall. Upon meeting the entry pressure of the fault, drainage of the cataclised zone occurs as a highly non-linear / non-uniform process, with the percolating pathway into the downstream portion of the sample acting as a function of intra-fault capillary heterogeneities and macroscopic fault thickness. These results suggest that wettability alteration of the host strata, promoted by enhanced contacts between nonwetting phase fluids (i.e. oil / scCO₂) and the pore wall upstream of faults, may reduce recovery factors during waterflood flood in petroleum reservoirs, and may limit the effectiveness of residual trapping mechanisms for CO₂ sequestration operations. Moreover, our observations pertaining to the dynamic nature of fluid flux through a cataclastically faulted porous media suggests that Darcy approximations for faults is untenable at the local scale.



NOTES:

Variation of uniaxial compressive strength in different architectural elements of fault zones

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Fault zones are likely to affect the mechanical resistance of the rocks. The way the fault will affect the rock strength depends mainly on the fault mechanism and the rock properties. In porous sandstones, the presence of brittle structures known as deformation bands (DB) i.e, thin tabular mm-thick structures with mm- to cm-scale offset, are able to alter the properties of the host rock, such as mechanical resistance and hydraulic behavior. Additionally, well developed deformation band zones can result in reservoir compartmentalization. This work aims to understand the variation of the mechanical rock resistance in different regions in a complex fault zone. As study case, we used porous conglomerates affected by deformation bands in the Rio do Peixe Basin, Northeast Brazil. We compared the measurements of Unconfined Compressive Strength (UCS) in three different outcrops representatives of the (1) fault core, (2) fault damage zone and (3) protolith undeformed (figure 1). The UCS data was acquired in situ directly in the deformation band and near the deformation band. For that, we used N-type Schmidt Hammer. Additionally, we performed perpendicular scanlines, measuring the deformation band frequency and thickness. The studied fault zone is composed of several transtensive leftlateral faults and exhibits complex anastomosed geometry. The fault core is evidenced by cm- to m-thick clusters, forming well developed deformation band clustering zones. In the damage zones, cm-thick clusters are formed. The damage zone is differentiated from the fault core mainly by the thickness of the clusters and the increasing of the spacing between clusters. The undeformed host rock is identified by the preservation of its sedimentary structure such as well-defined trough cross-bedding and the total absence of deformation bands. In deformation band clustering zones, considered the main fault core, the deformation band frequency is intense, reaching the average of 1.3 bands per meter. In such zones, the thickness of the deformation bands reached 6,35 mm. The UCS values obtained in the deformation band clustering zones reached around 46.2 Mega Pascal (MPa). In the damage zone, the average of deformation band frequency observed was 0,9 bands per meter, with deformation band thickness of 3,25 mm and UCS average value of 13.85 MPa. The non-deformed host rock presented low cohesion values, with average UCS of 10 MPa. Based on the obtained results, we conclude that fault zones in porous conglomerates present different mechanical resistance within the same fault zone. This effect occurs due the different strain intensities along the fault zone. In the main fault core, were deformation band clustering zones is formed, the rock is susceptible to high UCS value due the strain. This effect is reduced with the increasing of the distance of the main fault core, were the intensity of strain is lower.

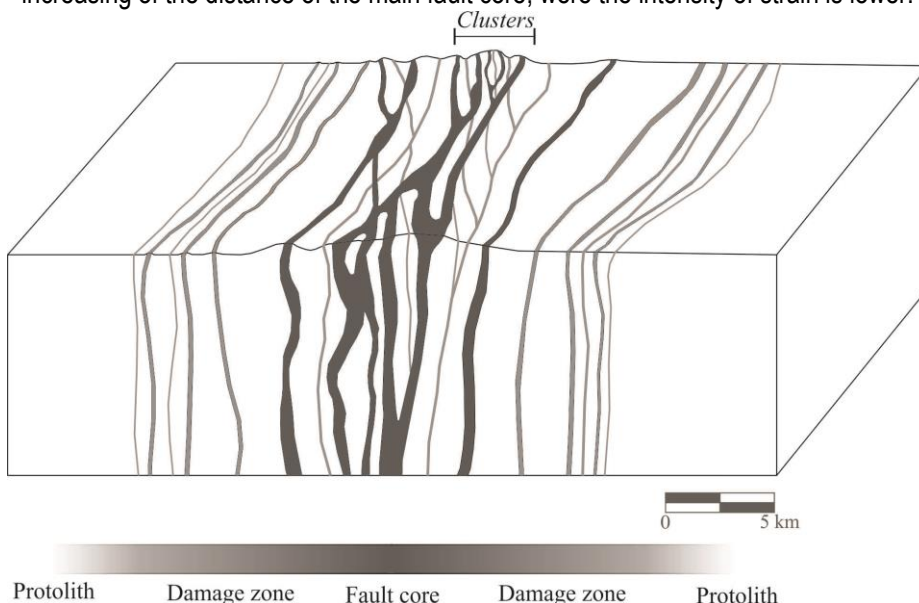


Figure 1: Different architectural elements of the fault zone.

Keywords: Architectural elements of fault zone; Uniaxial Compressive Strength; Deformation bands.



NOTES:

Thursday 16th November 2017
Session Four: Lab & Geomechanics 2

Invited Speaker: Fault permeability evolution with clay smears in hybrid failure – insights from analogue models and flow simulations

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Fault processes are complex phenomena that defy reliable prediction of detailed 3d geometry and hence permeability. Clay smear is particularly difficult to predict for sub-surface flow applications and would benefit from an improved understanding of controlling processes. In this study, we present a series of water-saturated sandbox experiments (Fig. 1A) producing large clay smear surfaces up to ~500 cm² (Fig. 1B). In these experiments, we couple across-fault flow measurements with structural analysis of post-mortem excavated clay smear surfaces. To develop a tool for evaluating the evolving fault structure during formation, we compare measured flow data to simplified numerical flow simulations using a finite element method.

We perform a series of experiments with one or two layers of normally consolidated clay and a cumulative thickness of 10 mm at 100 mm displacement. Our results show diagnostic relationships between the observed fault structures and measured across-fault flow. In a structural domain of graben faulting, we observe that the clay initially yields in hybrid brittle/ductile failure. Characteristic for this type of failure is an early development of laterally alternating brittle fracturing and shear faulting. The brittle fracturing at this early stage of fault formation causes increased cross-fault flow (Fig. 1C). We observed that holes preferably form beneath dilatant parts of the footwall cutoff in the clay layer. These can be identified in map-view as the fault curves towards the hanging wall.

During the evolution of the fault the formation of dilatant parts of the clay protruding towards the hanging wall is typically followed by fault back-stepping, formation of clay smears and reworking of clay fragments in the fault. These processes lead to slower increases of cross-fault flow. Holes that formed during the early breaching of the clay layer mostly remain open during the evolution of a fault, although there is some evidence for occasional resealing of holes. Fault zones are segmented by fault lenses, breached relays and clay smears in which sand and clay mix by deformation. A conceptual diagram of the across-fault permeability is shown in Figure 1D.

Experiments with two clay layers show that holes rarely form at the same position on the fault planes. This produces a layered sand-clay fault rock with greater tortuosity and therefore lower overall permeability than in one-layer experiments (Fig. 1E).

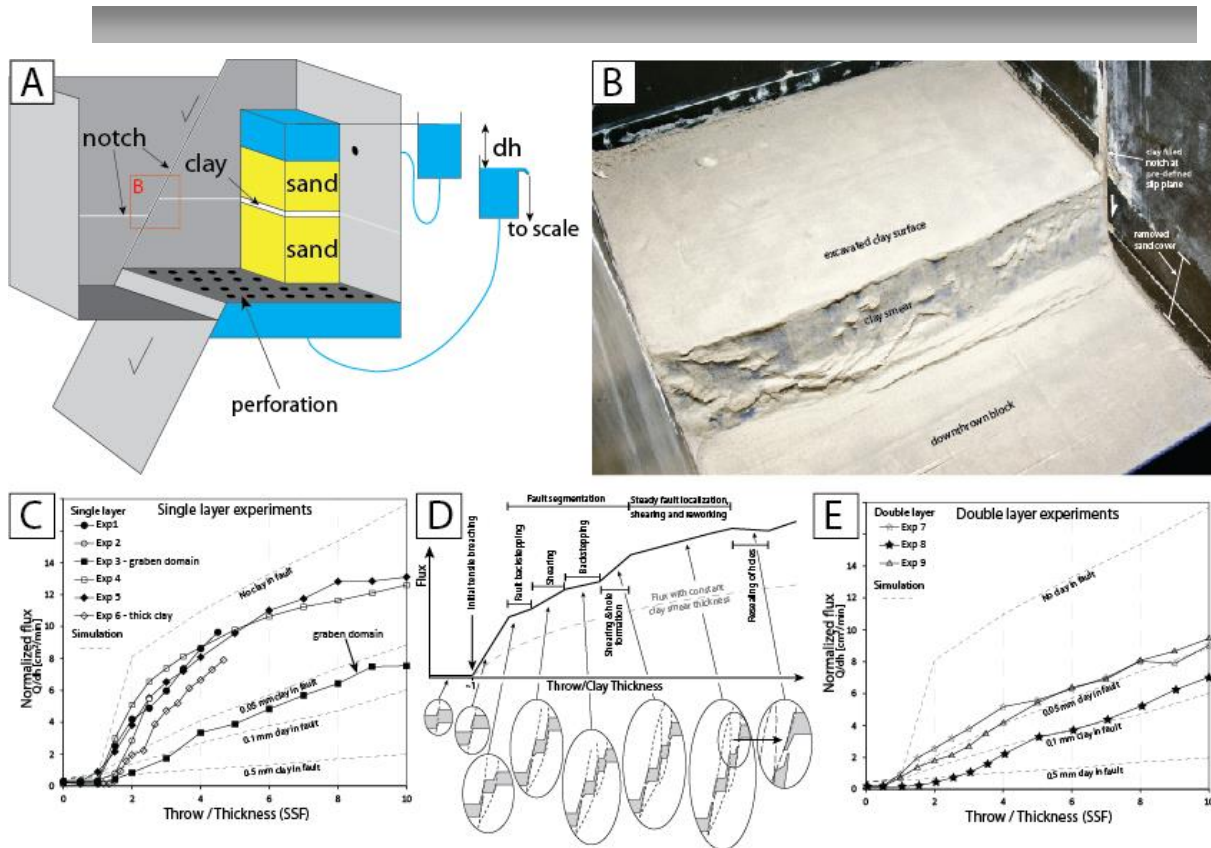


Fig. 1: (A) Experimental setup with a clay layer embedded in two sand layers above a rigid basement fault. The system is water saturated and hydraulic head difference between top and bottom sand induces flow across the faulted clay layer. (B) Excavated clay smear after maximum displacement was reached. Clay smear surface is ~ 500 cm². (C) Flow response vs displacement for single-layer experiments. (D) Conceptual diagram explaining the different phases of clay smear formation and deformation. (E) Flow response vs displacement for two clay layers.



NOTES:

Comparative influence of normal and shear stresses on the hydraulic conductivity of thin cracks in a tight quartz sandstone, a granite and a shale

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Conductivity of fluids along fractures in rocks is reduced by increasing normal stress acting across them, demonstrated here through gas flow experiments on a shale, and oil flow experiments on Pennant sandstone (equivalent to a tight gas sandstone) and Westerly granite. For all of these rocks the matrix permeability is comparable and very low. Additionally, the effect of imposing shear stress at constant normal stress was determined, until frictional sliding started. In all cases, increasing shear stress causes an accelerating reduction of hydraulic conductivity by one to three orders of magnitude as slip initiated, as a result of the formation of wear products that block fluid pathways. Only in the case of granite, and to a lesser extent in the sandstone, was there a minor amount of initial increase of conductivity prior to the onset of slip. These results cast into doubt the commonly applied presumption that cracks with high resolved shear stresses are the most conductive. In the shale, crack conductivity is commensurate with matrix permeability, such that shales are expected always to be good seals. For the sandstone and granite, unsheared crack conductivity was respectively 2 and 2.5 orders of magnitude greater than matrix permeability. For these rocks crack conductivity can dominate fluid flow in the upper crust, potentially enough to permit maintenance of a hydrostatic fluid pressure gradient in a normal (extensional) faulting regime, maximising frictional resistance to fault movement.



NOTES:

Methodology for improved prediction of fault properties using data from the CO2CRC Otway CCS Project

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³ CO2CRC / CSIRO Petroleum

The CO2CRC Otway Project in Victoria, Australia has successfully demonstrated safe CO₂ storage involving transport, injection, and monitoring of CO₂-rich gas into a geological storage site. The Otway Project has been in operation since 2008 and has conducted experiments both in a depleted gas field and in a saline formation. In the future, a new Otway Stage 3 experiment will be undertaken, with various experiments in the planning stage, some of which will monitor CO₂ behaviour in and around fault zones. Over the past decade a significant amount of work was conducted to assess how faults would behave both hydraulically and stability-wise when exposed to pressurized CO₂. Based on some preliminary monitoring results, the fault modelling was very successful in predicting the hydraulic behavior of one specific fault at the Otway site during an injection test in 2016.

There remains much uncertainty about the strength of the faults in term of cohesion and friction, key parameters for accurate prediction of fault reactivation risk in CO₂ storage. In this paper, we present results from a rock mechanical testing programme designed to understand and predict these key fault parameters that are needed when conducting fault stability modelling. We use both scratch testing on intact core, as well as triaxial tests on carefully selected samples to characterize the strength, frictional and poroelastic properties of the rocks and subsequently use these to infer the potential strength properties of the faults. The results presented, as well as being relevant for the Otway Project, provide a knowledge base that can be applied to CO₂ storage sites around the world.

In this study we use the scratch test, which measures strength heterogeneity of the host rock at the centimeter scale. This high resolution technique allows one to understand how factors such as fracture density and mineralogy affect the compressive strength and, therefore, cohesion. Correlations between measured mechanical properties and various logs can then be developed to produce some prediction of fault behavior during injection. During the test campaign, about 80 m of core was scratched from the CRC-2 well. Well logs were used to identify regions possessing some heterogeneity, then results of the scratch tests were compared on the fly with the various logs (density, porosity, sonic) to adjust any wireline stretch offset. The unconfined compressive stress (UCS) values measured by the scratch technique vary greatly, from under 5 MPa to about 150 MPa. This is a very wide range that is very favorable for developing proxies for UCS over different lithological facies. Three main well logs correlated well with the UCS: combinable magnetic resonance porosity, high resolution density and the photoelectric effect. Each parameter exhibits a good correlation to UCS albeit with some data scatter. To reduce the scatter, we have conducted a multi-variate analysis which has resulted in the development of a proxy for UCS based on the three petrophysical logs described above:

$$UCS = -320 - (1.42 PEF) + (0.15 \rho) - (13 \phi)$$

where PEF is the photoelectric factor log, ρ is density, and ϕ is the porosity as determined by the combinable magnetic resonance tool. The proxy for strength was then applied to the logs for a nearby well CRC-1, in which wireline and micro-image data was collected through a fault measuring approximately 1.5 m in width. The results show that the splay fault at 1420 m MD is predicted to have a strength of approximately 20 MPa. This indicates that the fault is likely to have a significant degree of cohesion and tensile strength. This is also supported by the fact that formation microresistivity images of the fault zone indicate significant cementation of fracture sets.

A series of triaxial tests were also conducted to determine the poroelastic and peak strength characteristics of the local rocks. However, for the purposes of this paper, the real interest lay in the behavior of the specimens following failure. Once each specimen failed in shear mode, deformation was continued at various strain rates so that the "faulted" specimens could be assessed in terms of whether they were velocity strengthening or weakening, or displayed strain weakening or hardening. These observations can potentially be used to understand how the large faults would behave seismically when pressurized beyond the critical point. Results of the velocity tests indicate that all specimens increased in frictional resistance when subjected to increases in strain rate, and vice versa. The changes in sliding resistance were on the order of 2-5 MPa per decade change in strain rate, and appears to

increase with increasing confining pressure. Although the experiments are not ideally designed to measure friction, we believe they do provide important qualitative information on the rocks.

Overall, the experimental results suggest that the faults in the vicinity of the CO₂ injection experiments do possess some significant strength that will help prevent fault reactivation. Furthermore, the frictional characteristics appear to be conducive to such experiments, in that they should be more favorable to aseismic creep rather than result in seismic instability. We plan to follow up these experiments with tailor made direct shear tests, in which quantification of the frictional parameters can be conducted. In addition to the results being applicable to the Otway project, we believe this workflow can be applied at any CCS site to gain a better understanding into fault mechanical behavior.



NOTES:

Adding probability to the prediction of fracture stability by quantifying the influence of in-situ stress, cohesion and friction coefficient

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Fracture stability depends on fracture orientation relative to the in-situ stress field and can be quantified by measures such as slip tendency (T_s), dilation tendency (T_d) and fracture susceptibility (S_f) (Morris et al. 1996; Ferrill et al. 1999; Streit & Hillis 2004). In industrial cases the underlying data are often limited, leading to significant uncertainty in estimates of fracture stability.

Quantifying fracture stability is crucial to petroleum industry, geothermal energy, hydrogeology, nuclear waste storage and seismic hazard prediction, as the success of operations depends on reliable estimates of fractures as sealing or fluid-conductive. Fracture stability prediction is sensitive to in-situ stress regime and material properties (Figure 1). The variability of the above factors and their respected uncertainties are considered for the provision of a probabilistic approach to predict fracture stability.

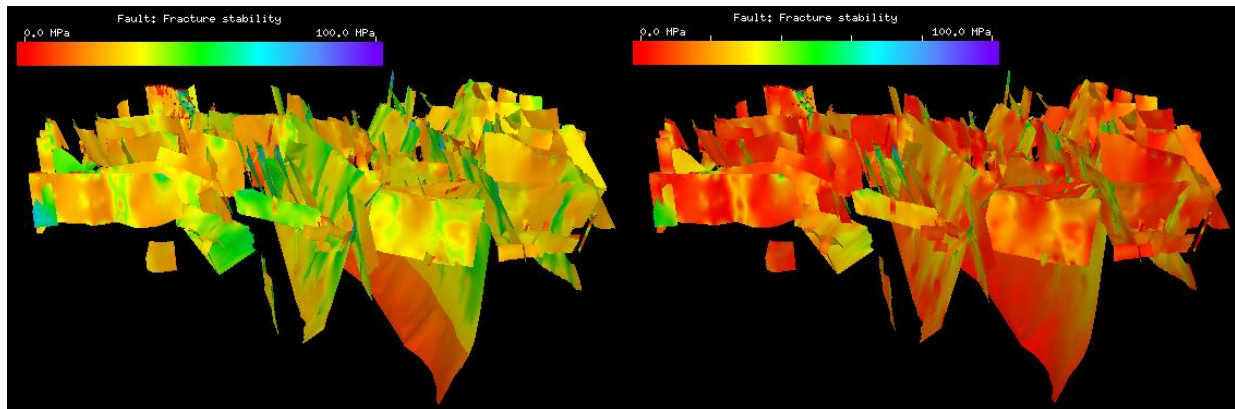
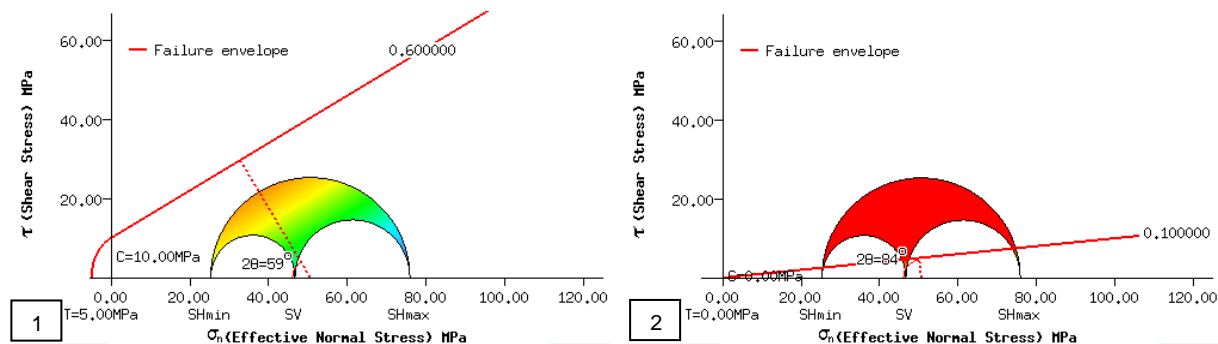


Figure 1: Change in cohesion estimates (+10 MPa) and friction coefficient estimates (-0.5) leads to re-activation of most fractures in the (pre-fractured) reservoir (left: before alteration, right: after alteration).

In previous findings we have estimated values for vertical stress, horizontal stresses and pore pressure from well logs and leak-off tests to make probabilistic predictions of fracture stability. We found in-situ stress and pore pressure predictions to vary by as much as 20%. Here we widen this study by investigating the influence and variation of material properties cohesion and friction coefficient (C_0 and μ) on fracture stability. These properties influence the position of the failure envelope in Mohr circles and hence the assessment of critically stressed fractures (CSF) by exceeding the failure envelope ($\tau \geq C_0 + \sigma_n \cdot \mu$, Barton et al. 1995) (Figure 2). A range of previous correlations have been derived from laboratory data on C_0 values, whereas only few attempts exist to determine the relationship between μ and geo-/petrophysical measurements (Chang et al. 2006).



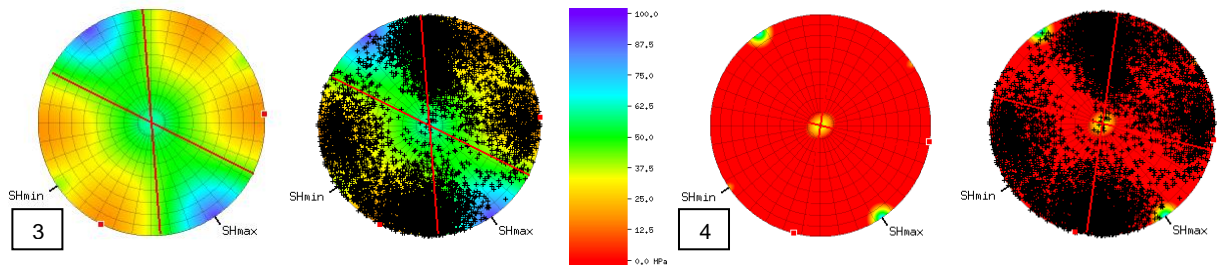


Figure 2: Analysis of fracture stability at reservoir depth. 1) Mohr diagram displaying stable stress regime. 2) Mohr diagram displaying critically stressed regime after combined variation of C_0 and μ . 3) Stereogram displaying positive fracture stability for poles to fractures. 4) Stereogram displaying mostly negative fracture stability for poles to fractures after material property variation.

We obtain estimates of C_0 and μ from wireline datasets including gamma ray, sonic, density and neutron porosity logs from mature oil fields in the NW German Basin and published correlations from laboratory experiments (Byerlee 1978; Weingarten & Perkins 1995; Lal 1999; Horsrud 2001; Gholami et al. 2014). We then systematically explore and quantify the influence of C_0 and μ on fracture stability to provide a more robust probabilistic approach to fracture stability prediction in an industry context. We find that fracture stability is highly sensitive to variations in μ , whereas individual variations in C_0 have no effect under the current setting. The greatest variation in fracture stability is achieved when friction coefficient and cohesion values are reduced in a combined approach.



NOTES:

Thursday 16th November 2017
Session Five: Integrated Outcrop 1

KEYNOTE: The internal structure of fault zones and its impact on fault seal

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Faults are not simple planar surfaces but can be seen in outcrop and on high quality seismic reflection data to often comprise two or more slip-surfaces onto which fault displacement is partitioned. The geometries of internal slip-surfaces within fault zones and the distribution of displacement on them can provide indications of how this complex internal fault zone structure formed. Analysis of these aspects of faults has led to the conclusion that many features of fault zone structure can be explained by the removal of wall-rock asperities, but perhaps more importantly, by the linkage between the elements of an array of initially collinear fault segments. The action of these processes on a wide range of scales and the structures that arise from them can be significant when considering the impacts of faults on flow in the subsurface. This presentation will review this description of fault zone structure and discuss its impact on the distributions of fault rock within fault zones and its implications for across-fault juxtaposition/connectivity of reservoir flow units.

Quantitative geometrical characterisation of fault zone internal structure in a variety of geological settings, and for faults of varying sizes, has led to the development of a quantitative description of fault zone structure. This is defined in terms of three parameters, fault segmentation frequency, the integrity of the boundaries between fault segments and the geometries of segment boundaries. These parameters, combined with a scale-invariant geometrical model of fault zone evolution, provide quantitative predictors of fault zone structure over a wide range of scales. These geometrical parameters can be related in some instances to lithology and depth at the time of faulting, an observation which provides quantitative constraints on internal fault zone structure, and therefore the flow impacts of faults in the subsurface. This scale-invariant description of fault zone structure is relevant to many fault seal related issues ranging from the likelihood that a relay ramp occurs between successive 2D seismic lines to the continuity of clay units across fault zones. This presentation will describe the findings of these analyses and discuss some of their implications.



NOTES:

Evaluating and improving fault seal workflows using outcrop analogues

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Understanding the hydraulic properties of fault zones has long been a problem for the exploration and production of oil and gas and other applications in subsurface engineering. Several different tools exist that attempt to predict the potential impact of fault zones on the movement of fluids in the subsurface. However, reliable predictions are still elusive. To improve the prediction of fault properties this paper analyses data on the structure and contents of 10 faults in the Colorado Plateau (SE Utah).

In this study we compare observations on faults in outcrops to predictions by commonly used fault seal evaluation tools. Outcrops of fault zones have been mapped in centimetre scale detail. By inferring which faults are likely sealing and which are likely non-sealing, we can compare these with predictions by commonly used fault sealing workflows. We compare predictions from SGR, ESG, SSF and CSP to the mapped fault zones. The values of these predictors have been calculated using V-shale curves derived from well logs. The comparison shows that for the faults in our dataset CSP is the most reliable predictor, correctly distinguishing between sealing and non-sealing faults for 8 out of 10 faults. CSP evaluates the combined effect of smearing of multiple beds of shale. This corresponds well to the architecture we can observe in the outcrops, where smeared shale and silt forms the dominant low permeability fault rock.

In addition to fault sealing we can use the dataset to estimate bulk permeability values for the fault zones. We compare these bulk permeabilities to the estimates of fault permeability provided by established SGR-based workflows. The comparison shows that the two different approaches yield very different results and the data shows no predictive relationship between the outcrop observations and the SGR-based permeability predictions.

The abundant smearing of silt observed in these outcrops is one of the key factors explaining the differences between the predictions by fault seal algorithms and the outcrop observations. Silt is not evaluated using the current methodologies, but can have a similar sealing effect as shale. In addition the four algorithms only evaluate shale incorporation, and do not evaluate other processes affecting fault sealing and permeability (e.g. formation of sandstone lenses, cementation, cataclasis, authigenic clay growth and cement dissolution).

The difficulty in predicting fault permeability suggests that more robust tools are required. To reliably evaluate fault zone permeability it is necessary to reliably evaluate fault architecture. We show that fault architectures are the result of a consistent set of geological processes (e.g. shale smearing, formation of sandstone lenses). By evaluating the likeliness of these geological processes, we can estimate the fault architecture most likely to be present at the reservoir interval. The predicted fault architectures can subsequently be used to provide robust upscaled permeability estimates and an estimate of the inherent uncertainty in the prediction.

Acknowledgements

The authors would like to gratefully thank Total for funding this research.



NOTES:

Implications of cataclasis for fluid flow across normal faults in a weakly lithified multilayer

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Fault-seal analysis in sand-shale multilayers emphasises the role of shale smear often without explicitly accounting for cataclasis (Figure 1a & b). Cataclastic processes can produce low-permeability fault rock and are examined here for small displacement (0.001 to 70 m) normal faults displacing weakly lithified turbidites comprising mainly (~55-80%) lithic grains. Late Miocene Mount Messenger Formation (MMF) turbidites from the North Island of New Zealand provide fault-rock data over a range of scales from individual grains (~0.1-350 μm) to the height of coastal cliffs (~10-20 m). Fault rock has been analysed using thin sections, SEM images (Figure 1d-f), particle-size distribution measurements (Figure 1c) and outcrops of faults mainly in cross section. Cataclasis associated with particle size and macroscopic porosity reduction of protolith sandstones commences at low fault shear strains (<1) and continues as fault displacement accrues (Figure 1d-f). The relationship between particle-size reduction (Figure 1c) and displacement is non-linear with initial rapid cataclasis facilitated by disaggregation of weak lithic and altered feldspar grains along pre-existing grain defects (e.g., grain boundaries, fractures and altered cleavage planes). Shale smear, by contrast, is not associated by significant particle-size reduction and appears to have been achieved by intergrain slip and associated micro-faulting. Despite the occurrence of shale smear, cataclasis can produce a significant proportion (>50%) of the total fault-rock in sand-shale multilayers. The resulting fault-rock thickness varies by up to three orders of magnitude for a given fault displacement and over short distances (<2 m) along individual faults.

Variations in fault-rock thickness and associated cataclasis have the potential to modify the hydraulic properties of faults. Where cataclasis produces a significant component of the total fault rock the fraction of clay minerals in a faulted sequence cannot be assumed to provide a proxy for the composition of fault rocks. In cases where cataclasis makes a significant contribution to fault rock, these faults may comprise more clay than predicted by shale-smear algorithms leading to fault-permeability which is higher than the predicted values. A number of explanations could account for why such over-estimates do not appear to contravene predictions based on empirical data and the shale-smear concept. First, although cataclasis produces significant amounts of fault rock in the MMF (perhaps due to the high proportion of weak lithic and altered feldspar grains), it may be less important in quartz-dominated sandstone reservoirs. Second, the number and lengths of shale smears in multilayers are over-estimated by the available algorithms (e.g., because not all shale beds smear; see Watson et al., this volume) and these over-estimates are approximately balanced by 'excess' fault rock formed by cataclasis. For such a scenario the processes responsible for the generation of fault rock would be more complex than the conceptual shale-smear model. Third, although cataclasis increases the volume of fault rock, it may not significantly modify the fault-rock permeability. On average shales and shale-derived fault rock have lower permeabilities than cataclastic fault rock (shales 0.0008 to 0.000007 mD versus 0.03 to 0.00003 mD for cataclasites; Childs et al., 2007; this study). However, the available data support the view that with increasing shear strains cataclasis in the MMF can generate grain-size and permeability reductions in fault zones similar to those of the shales (Figure 1c). Therefore, in these rocks cataclasis can retard across-fault flow within sandstone beds.

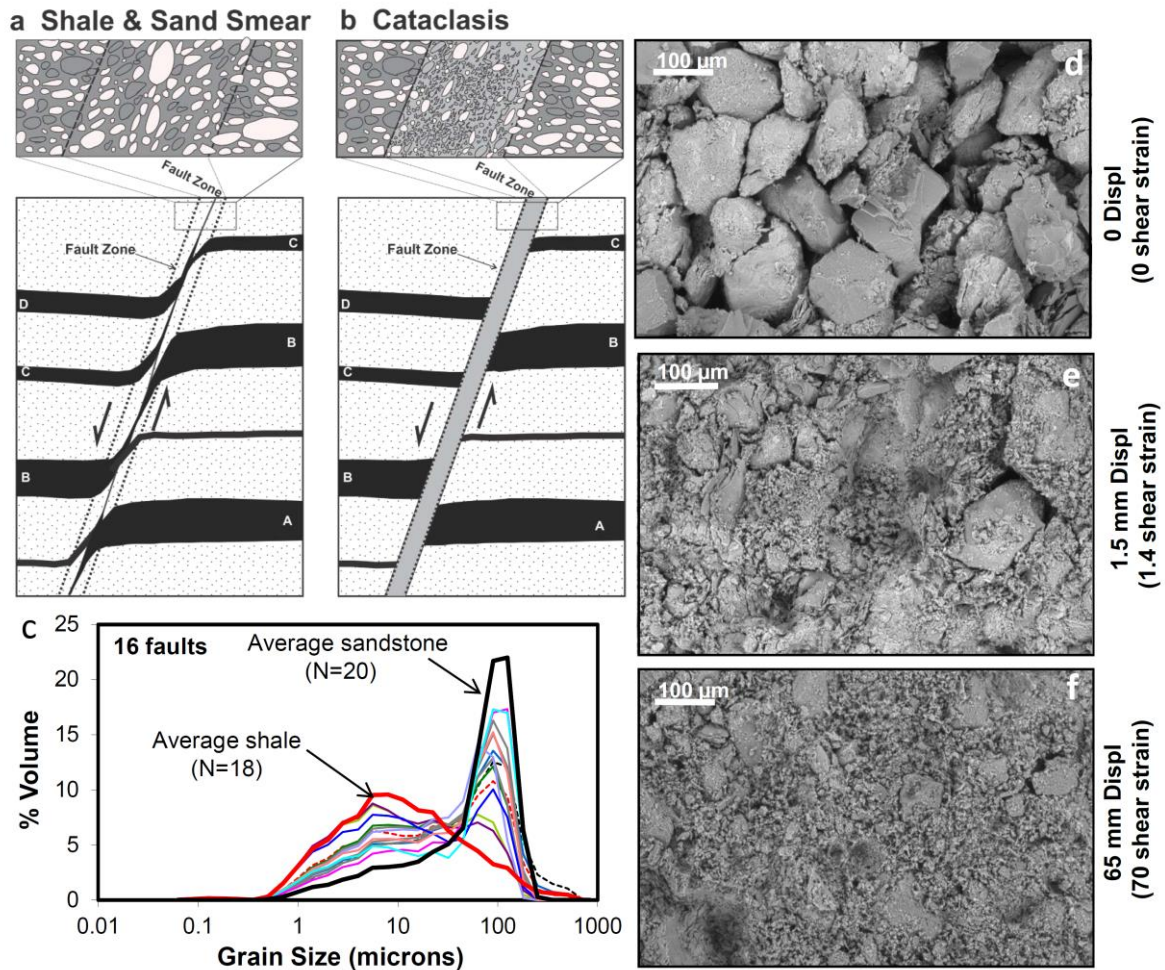


Figure 1. Schematic diagrams showing current models for fault-rock developed by (a) sand-shale smear and (b) cataclasis. Displaced beds are labelled and dotted lines in lower diagrams define fault-zone boundaries. (c) Particle size distributions for cataclastic fault rock (thin coloured lines), average sandstone (thick black line) and average shale (thick red lines) beds within the MMF. Red thick lines indicate the average curves, which, for the purposes of this diagram, are parallel and produce fault zones of constant thickness, which is an oversimplification for most fault zones. (d, e & f) SEM backscatter images of unfaulted sandstone (d), fault rock with 1.5 mm displacement in sandstone (e), and (c) fault rock with 65 mm displacement in sandstone. Note the decrease in grain size with increasing displacement.



NOTES:

Thursday 16th November 2017
Session Six: Integrated Outcrop 2

Invited Speaker: Fault zone deformation and fluid history in mechanically layered mudrock and chalk

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Faults in self-sourced reservoirs and other low permeability strata commonly form conduits for fluid movement within and between mechanical stratigraphic beds or layers. Faults are usually the largest fractures in the fracture network, and form the backbone of the fracture porosity system. If appropriately oriented, faults frequently become reactivated during hydraulic fracturing, and may be conduits for water incursion, thereby representing an economic risk to a given well or wellfield. Faults in outcrop exposures of the Eagle Ford Formation and the Austin Chalk – both important oil and gas reservoirs in the subsurface of south Texas, U.S.A. – exemplify deformation and fluid histories of subseismic scale faults in mechanically layered mudrock- and chalk-dominated strata. Natural stream cuts and road cut exposures of nearly horizontal Eagle Ford Formation and Austin Chalk in south and west Texas expose northwest- and southeast-dipping normal faults with displacements of 1 cm to 7 m cutting mudrock, chalk, limestone, and volcanic ash. Fault dips are steep to vertical through chalk and limestone beds, and moderate through mudrock and clay-rich ash, resulting in refracted fault profiles. Steeply dipping fault segments contain rhombohedral calcite veins that cross the fault zone obliquely, parallel to shear segments in mudrock. With additional displacement, tabular sheets of calcite have grown at dilational steps by repeated fault slip, dilation, and cementation. The vertical dimensions of the calcite veins correspond to the thickness of offset competent beds with which they are contiguous, and the slip-parallel dimension is proportional to fault displacement. Failure surface characteristics, including mixed tensile and shear segments, indicate hybrid failure in chalk and limestone, whereas shear failure predominates in mudrock and ash beds – these changes in failure mode contribute to variation in fault dip. Slip on the shear segments caused dilation of the steeper hybrid segments. All of the faults studied show crack-seal textures that document numerous reactivation events, with the refracted fault profiles persisting as the active fault geometry. Local fault zone behaviors (dilation versus slip) are well predicted by slip and dilation tendency analysis of the complex fault shapes within the interpreted ambient stress field at the time of faulting. Fluid inclusion and stable isotope geochemistry analyses of fault zone cements indicate episodic reactivation at 1.4 to 4.2 km depths. Fluids include locally sourced saline waters as well as externally sourced waters and oil with larger displacement faults (typically >1m displacement) tending to tap into external fluid sources. The results of these analyses illustrate fundamental bed-scale lithologic control on fault zone architecture that is directly relevant to the development of porosity and permeability anisotropy associated with faults. These observations on fault zone mechanics and associated fluid flow have direct implications for natural and induced fracturing in unconventional hydrocarbon reservoirs.



NOTES:

3D anatomy of a composite shale smear: along-strike variations of fault zone architecture and deformation mechanisms of normal faults in poorly lithified sediments, Miri (Malaysia)

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Shale smearing has long been recognized as one of the key mechanisms for membrane fault sealing. Where a fault offsets multiple beds of shale, these can be concatenated into a composite shale smear. The study site in Miri offers unprecedented exposure of a composite shale smear fault architecture. We use this site as a natural laboratory to investigate the linkage of multiple smaller smears into a composite smear and to quantify the risk of discontinuities in the smear, allowing potential leakage across the fault.

Normal faults at our study site in Miri offer 3D along-strike and sub-vertical exposure due to the clearing of an area of land of 1 km². Such an extensive along-strike exposure is very rare, but permits analysis of detailed along-strike variation in fault structure and fault rock properties, and the impact this variation can have on hydraulic properties. Whether a fault acts as a conduit, barrier or combined conduit-barrier to fluid flow is strongly determined by the internal fault zone architecture. The hydraulic behaviour of faults at depth plays an important role in the exploration and production of hydrocarbons, storage of CO₂ and other subsurface engineering applications.

The object of this study is a set of normal faults cutting poorly consolidated deltaic sandstone-shale sediments of the Baram Delta. The aim is to investigate the highly variable nature of 1) the architecture of the fault and 2) the properties of the fault rocks. In the study area the succession is dominated by sand beds, with some interbedded clay-rich beds 0.2-2 m thick. The outcrop contains a major normal fault trending ENE-WSW and dipping south. It is not possible to correlate any bed from the footwall to the hanging wall because the main fault displaces the entire exposed stratigraphy, therefore only the minimum offset is constrained by the thickness of the hanging wall (>20 m). The large fault is associated with a conjugate set of normal faults with the same trend dipping NNW and SSE at 45-70°.

The damage zone of the major fault is characterised by deformation bands, zones of shear and gentle folding. The damage zone also contains fractures that postdate the faulting. The fault core is composed of dark grey, foliated clay. The foliation is marked by white sandstone lenses up to 40 cm long embedded in the matrix and elongated sub-parallel to the fault core edges. Clay smears are incorporated into the fault core through folding and shearing, in a stair-stepping, or telescoping geometry. The continuity within the fault zone of a single clay smear originating from a 20-30 cm thick footwall bed can be traced up to 2.5 m down-dip (about ten times its thickness) and up to 7 m along-strike. Sand smears, on the other hand, extend for a maximum distance that is double the sand bed thickness (2 m of sand smear from a 1 m-thick sand bed).

Microstructural analysis of the samples collected in Miri show particulate flow as the dominant deformation mechanism, combined with minor cataclasis, pressure-solution and growth of authigenic clays. Both the secondary shear zones and the fault core are dominated by compositional banding driven by grain rotation and rearrangement, while there is little evidence of mixing at the grain scale.

Key observations are related to the along-strike thickness (1 cm - 60 cm) and clay content (<5% - 90%) variability of the fault core. Eight areas that could represent potential cross-fault pathways have been identified over the 56 m of exposed fault. Six of these are due to the thinning of the clay-rich fault core to less than 1.5 cm, while in the other two areas the clay gouge is interrupted, resulting in sand-on-sand juxtaposition.

Across the length of the exposure there are considerable fault core thickness variations over short distances, while throw is not likely to vary that much. The fault core thickness variation is influenced by stratigraphic changes (bed composition and thickness), by fault wall irregularities and by secondary shears.

When upscaling this fault architecture to the size of reservoir simulator grid cells, using the average core thickness of the fault (17 cm) would poorly represent the true hydraulic properties of the fault. Reliable predictions of cross fault flow must focus on areas of thin clay gouge and sand-on-sand juxtaposition.

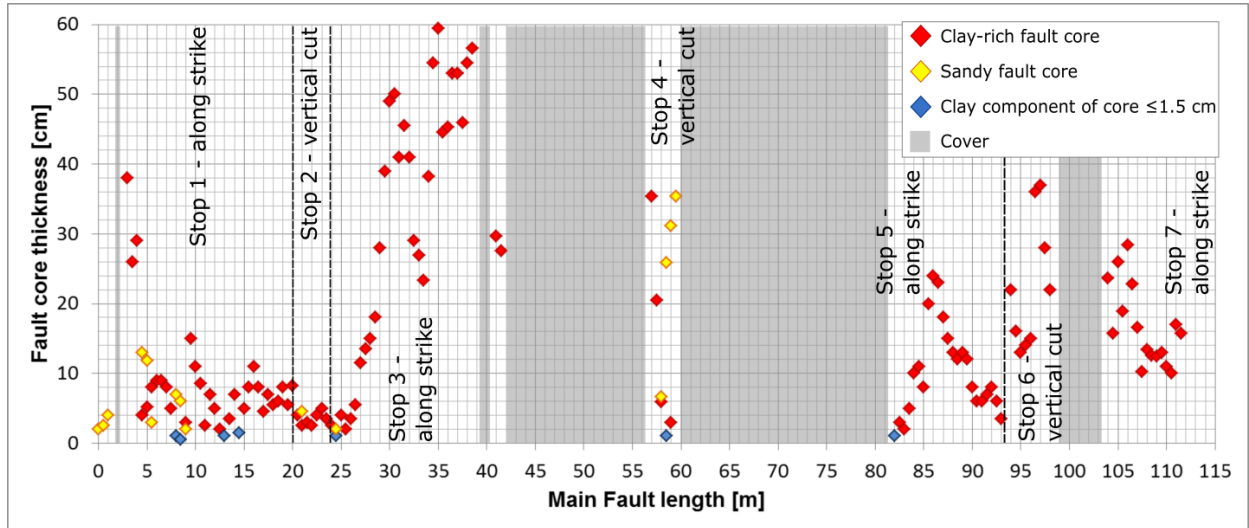


Figure 3: Fault core thickness and composition variation along length of the main fault, divided by along-strike and vertical cut stops; covered areas in grey. Red diamonds indicate clay-rich fault core; blue diamonds indicate very thin (< 1.5 cm) clay-rich fault core; yellow diamonds indicate sandy fault core (at metre 1 and 59) or a sand lens inside the clay-rich fault core.



NOTES:

Fault injectites: Implications for fluid flow along and across faults

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Fault zones, and the fault rocks within them, display a wide range of behaviours with respect to fluid flow. They can act as seals, baffles, barriers or conduits. This diversity has been attributed to many different factors including original lithology, fault displacement, overall deformation history and depth of burial. Another potentially significant variable is the presence of material injected into the fault zone from either the hanging wall or the footwall. These injected rocks typically display much higher porosities and permeabilities than the enclosing fault rocks, and can therefore serve as drains or conduits in otherwise sealing fault zones. In this contribution, we describe fault injectites from four locations (three in the UK and one in Malta), including both injected sandstone and limestone, and situations where the source rock for the injectite is located in the hanging wall or the footwall.



Figure 1. Photographs of fault injectites in outcrops. Clockwise from left: sandstone injected into granitic fault breccia at Helmsdale (Scotland, UK; oblique view onto wave cut platform, pen approx. 15 cm long); micritic limestone with flow fabric injected into brecciated coralline limestone (Madliena Tower, Malta; section view, coin approx. 2 cm across); sandstone injected into brecciated and veined mudstones at Scapa Bay (Orkney, UK; plan view, pen approx. 15 cm long).

At Helmsdale (Scotland, UK), the Helmsdale Fault is injected by sandstone derived from the hanging wall stratigraphy. A fault breccia derived from the Helmsdale granite is intruded by an array of thin (few centimetres wide), bitumen-stained, sandstone dykes. The probable source of this injected sand is the Jurassic deep marine Allt na Cuile sandstone in the immediate hanging wall, beneath the present erosion level. At Scapa Bay (Orkney, UK), the North Scapa Fault is also intruded by sheets of sandstone (up to 15 centimetres across), emplaced into carbonate-cemented fault breccias, derived mostly from lacustrine Stromness Flags (Devonian). The source of this injected sand is thought to be the fluvial Scapa Sandstone Formation (Devonian) in the immediate hanging wall. At Arbroath (Scotland, UK), Middle Devonian fluvial sandstones in a narrow normal fault zone are intruded by mixed sandstone-calcite dykes, concentrated in the immediate footwall to the fault. At the Madliena Tower (Malta), the Victoria Lines Fault shows injections of Globigerina Limestone (Miocene) from the hanging wall into a relay between two fault segments hosted in the Lower Coralline Limestone (Oligocene).

We present outcrop and laboratory data from each of these four cases. The outcrops reveal the spatial heterogeneity of the injected sedimentary material, and the juxtaposition with fault rocks of very different petrophysical character. Using outcrop maps, photographs and cross-sections we show that the injected sediments are connected, both laterally (along strike) and vertically (along dip). The laboratory data show that the porosity and permeability of the injected material are significantly higher than the enclosing fault rocks. Our analysis shows that fault injectites: 1) form connected pathways within the fault zone and, presumably, connect back to the source formation in either the hanging wall or footwall; 2) have higher porosities and permeabilities than the enclosing fault rocks; 3) probably act as drains or conduits for fluids in otherwise low permeability, sealing faults. Simplified hydraulic models of fault zone behaviour based on the measured or inferred permeability of fault rocks alone probably need revision.



NOTES:

Shale-smear continuity in a poorly lithified turbidite; implications for fault-seal potential

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Fault-seal algorithms developed for the petroleum industry primarily use shale-bed thickness and displacement to estimate seal potential, with these algorithms assuming that low-permeability fault rock is primarily entrained (e.g., smeared or dragged) into fault zones from clay-rich beds in the host rock (e.g., Giger et al., 2013). Fault-seal equations were mainly developed from outcrop observations and assume that all shale beds smear and contribute to fault rock. Here we test the assumption that all shale beds smear by quantifying the proportion of beds that smear for a turbidite sequence that comprises interbedded mudstone (~1-45 cm thick) and sandstone (~1-150 cm thick), and examine the implications that the results might have for the use of shale-smear algorithms. Data are from coastal outcrops comprising small normal faults (displacements 2 cm to 1.1 m) which offset poorly lithified beds (burial depths ~1-1.5 km) of the Mount Messenger Formation in Taranaki, New Zealand. Over 180 faulted shale beds with 100% exposure were randomly sampled and show that 39% (N=71) of beds have no smear, 53% (N=97) discontinuous smear and 8% (N=15) continuous smear (Figure 1). The median smear continuity is ~3%, while half of the discontinuous smears have continuity of <23% and ~83% of all smears have continuity of <50% (Figure 1). The majority of smears had variable thicknesses which were often unrelated to source-bed thickness or distance from the source bed. These thickness variations can result from secondary faults within the fault zone which locally thicken or thin the smear depending on the geometries and displacements of the secondary faults. Individual shale beds displaced by adjacent faults, with comparable orientations, kinematics and timing of formation, can show smear and no smear, suggesting that in these cases bed composition (e.g., clay type), grain-size distribution, moisture content or lithification cannot account for the observed variations in smear occurrence. Instead, smearing appears to be common where fault deformation is most distributed and fault-zone thicknesses are greatest. Using the available data and published shale-smear algorithms we calculate Shale Smear Factor (SSF), Clay Smear Potential (CSP) and Shale Gouge Ratio (SGR) for the displaced beds. As with previous studies continuous smear (i.e. fault seal) is most likely for lower SSF and higher CSP or SGR values, although discontinuous and no smear cannot be discriminated by these methods (Figure 2). The available data support the use of a probabilistic approach for estimating the location of smears between horizon cutoffs (e.g., Childs et al., 2007), an approach that could also be extended to the occurrence and length of the smears. Independent of which algorithm is used shale-smear calculations could over-estimate the seal potential because not all beds smear and many of the smears are short in length. Further work is required to determine if our observations have wider implications for fault-seal estimates beyond Mount Messenger Formation rocks.

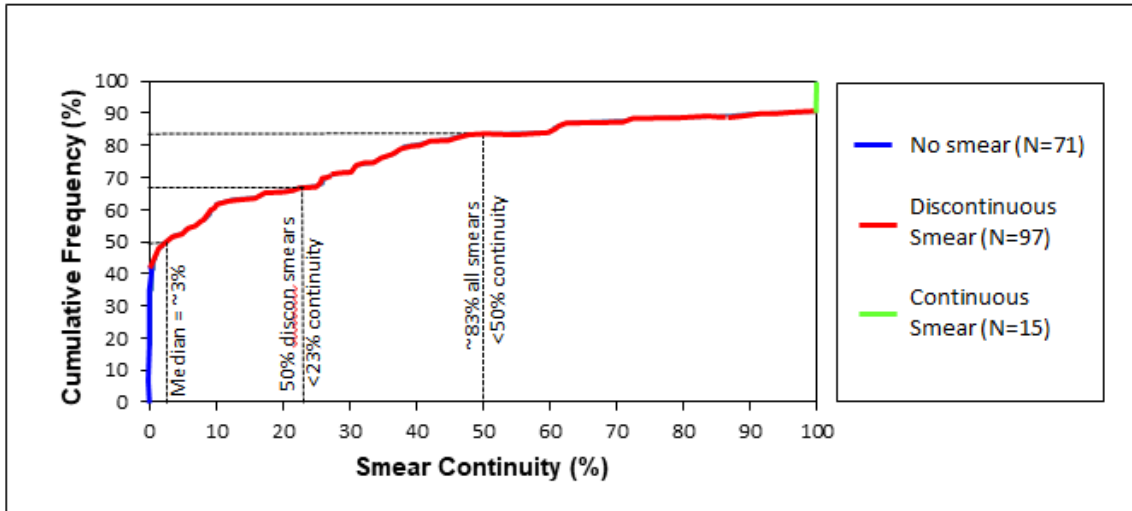


Figure 1. A cumulative frequency graph showing the range of shale smear continuity (0-2 = no smear, 2-99 = discontinuous smear and 100 = continuous smear). Shale smear continuity calculated by dividing the shale smear length by the displacement and multiplying by 100 to produce the percentage of the fault length covered by shale smear.

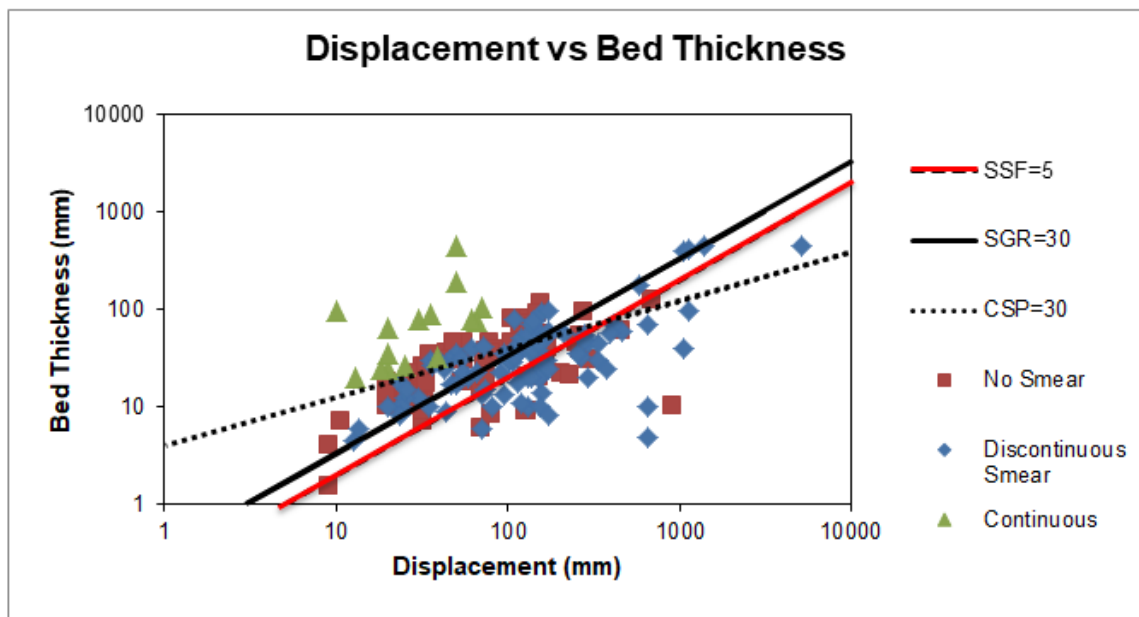


Figure 2. Displacement vs bed thickness for beds showing no smear (N=71), discontinuous smear (N=97) and continuous smear (N=15).



NOTES:

Thursday 16th November 2017
Session Seven: Modelling

Reservoir modelling strategies for intra-reservoir faulting

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Keywords: Geocellular modelling, fault seal, fault modelling

Small-scale, intra-reservoir faulting challenges reservoir modelling due to the large ambiguity of potential effects on fluid flow. Acquiring dynamic data during appraisal supplements prior information, however simulation is required to understand the sensitivity of the system.

Contemporary reservoir modelling requires early definition of a grid geometry, affecting estimated hydrocarbon volumes which may inspire reluctance to adjust reservoir geometry.

Faulting may affect reservoir flow properties by locally affecting the reservoir permeability and connectivity; affecting transmissibility across the fault itself and any related damage zone; and, by increasing tortuosity through displacement and juxtaposition of rock types with differing flow properties.

To consider these in flow simulation, we may represent faulting using various strategies, including: geometric expression of the fault, including juxtaposition and transmissibility of flow across the fault; vertical expression of the fault in an unchanged grid geometry with application of transmissibility multipliers; or, assuming fault effect is negligible and will be considered by calibration of the bulk permeability of the reservoir.

We present a series of reservoir simulations, representing each of these strategies to retrospectively add consideration of small-scale faulting. Using these data, we discuss the implication of modelling strategy on the results. Considering the purpose of reservoir modelling to be to facilitate decision-making.

We consider this work to provide a first-pass sensitivity analysis of production forecasting to simulation strategy. This provides the first stage of information to consider if further investigation is warranted, establishing broad sensitivities and allowing consideration of potential impact.



NOTES:

Stochastic Modelling of Fault Zone Permeability: Implications for Seal Analysis

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Fault zones are complex and show considerable variability in both structure and the distribution of associated fault rocks. The scale of this complexity relates to many variables including the mechanical properties of the multi-layer being faulted, the depth of burial when the fault was moving, and the kinematics of the fault (e.g. is it reactivated or an isolated new fault?) This creates considerable variation in the fault geometry both on a larger scale, where relay zones form fundamental components of the fault, and on a local scale, where the fault core, the zone that localises most strain and displacement, can show complexly varying elements such as low strain lenses and membranes of intensely deformed fault rock or entrained shale smears. The fault core largely controls the across-fault flow and sealing properties of the fault zone. In most production models this core represents what is mapped as the fault plane. Fault core widths scale with displacement and so the complexity of fault zone structure should similarly show a thickness-dependence. The internal make-up of the core, when viewed in outcrop, contains numerous anastomosing zones of fault rock of variable composition and attendant strain. All this complexity means it is impossible to deterministically model a complete fault zone and thus understand the spatial distribution of its properties. In this talk a stochastic approach is developed to modelling the fault core and its permeability structure. The approach uses four components to describe the fault zone: Shale smears, Phyllosilicate Framework Fault Rocks (PFFR or shaly gouge), Cataclastic Gouge and Low Strain lenses. Each "fault facies" is given four property ranges: length, thickness, permeability and V_{shale} . The fault model generates a random assemblage of these facies in a multi-domain calculator that allows up to 10 separate parallel domains to be included in the fault core (Figure 1). Across-fault seal potential is evaluated by using thickness-weighted harmonic averaging of permeability using a parallel plate approach, and is then related to the thickness-weighted arithmetic averaging of V_{shale} . The fault zone thickness is the sum of the thickness of individual domains. A composite smear envelope is also generated by summing the shale smears across the core for comparison with more rigorous shale smear models. While simple in concept and in construction, the results of the model offer a means to help understand the controls on fault zone permeability and controls on the potential fault leak point, the point that traps the minimum hydrocarbon column as a function of depth below the top of the modelled fault. Key conclusions from the modelling include:

1. Overall Fault zone permeability and thickness appear to be described by a crude Power-Law function of V_{shale} (Figure 2a).
2. The leak point depth is a key component of the fault seal analysis and needs to be factored into the seal evaluation (Figure 1).
3. The statistical variability in permeability (Figure 2a) can be simplified by looking at the leak point data from multiple realisations. This yields a much tighter relationship best described as a log-linear "tripartite dog-leg model" between V_{shale} and permeability (Figure 2b).
4. This dog-leg model reflects the discrete control imposed by Cemented Cataclasites and Lenses, PFFRs and Smears on the permeability as V_{shale} increases.
5. Low average V_{shale} faults ($V_{sh} < 10-15\%$) have the greatest permeability uncertainty (related to the influence of low strain lenses of host rock)
6. For intermediate V_{shale} faults ($15 < V_{sh} < 30-40\%$), permeability is a log-linear function of V_{shale} (the PFFR domain)
7. For high V_{shale} faults ($> 30-40\%$) the up-scaled permeability is given by that of the attendant shale (Shale Smear dominated), and is near constant (Figure 2b).

Calibration of the model to known sealing faults will be discussed. This allows the link between the up-scaled stochastic fault zone V_{shale} and SGR to be reviewed. The results show good agreement between the average V_{shale} and SGR measures when the stochastic thicknesses-weighted harmonic average permeability is similar in magnitude to that calculated independently for the sealing fault, and the proportion of smears in the stochastic model is matched to that calculated using the shale smear factor (SSF) based on a nearby well. The stochastic model results can be used to propose a new permeability model for fault zones that also offers the potential to generate a calibrated seal model, anchored to local well data, and thus able to overcome some of the limitations of using generic published algorithms.

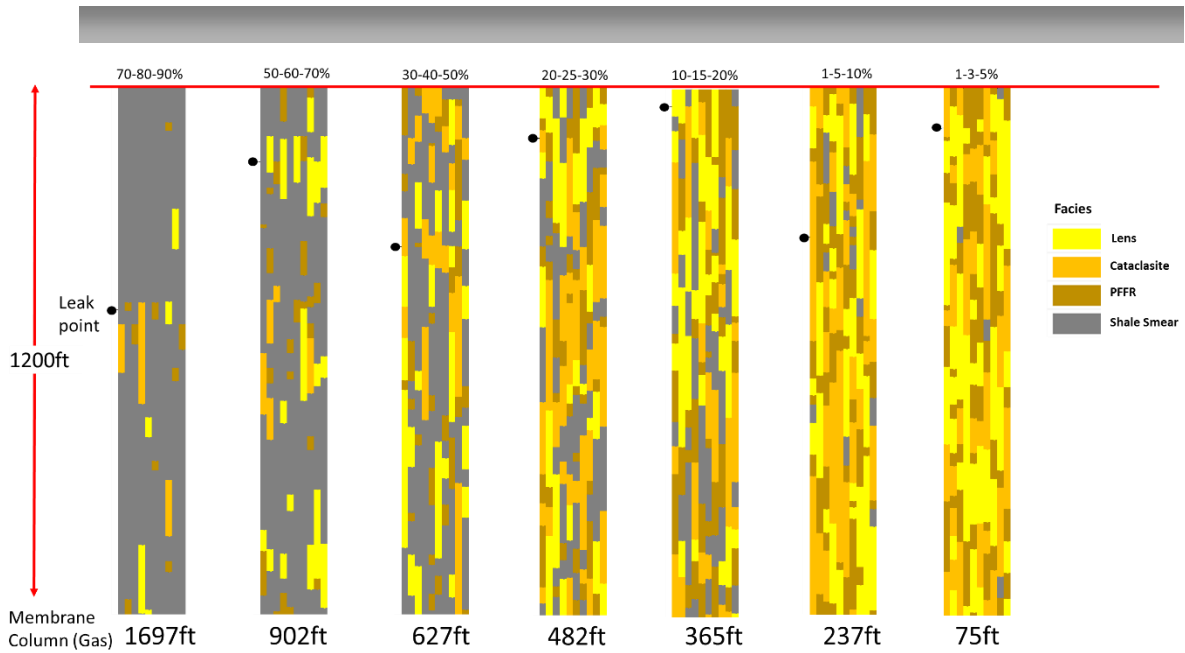


Figure 1. Example realisations from the stochastic fault model showing how variable clay content (controlled by the proportion of shale smears) affects the trapping of a gas column. The total trapped column is a combination of the leak point depth and calculated membrane sealed column.

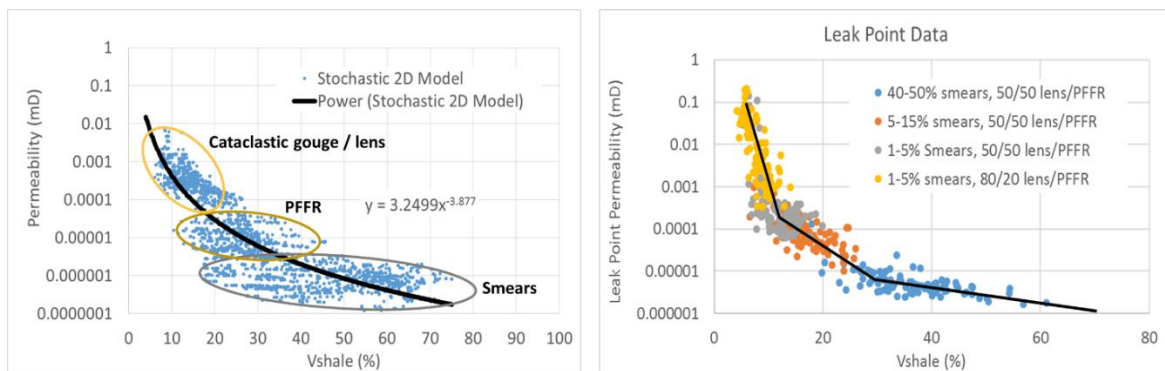


Figure 2. a) Plot showing results from the stochastic model. Permeability vs Vshale for multiple realisations show significant scatter but appears to define three separate fields, each reflecting different dominant fault rock facies. b) Extracting the leak point data from the models shows more clearly how the harmonic average permeability varies as a function of fault zone average Vshale.



NOTES:

Representation of small-scale fault displacement partitioning in reservoir modelling

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Normal faults in clastic reservoirs are usually visible only as single surfaces in seismic data, and generally can only be represented as single surfaces in reservoir models due to cell size limitations. Examination of reservoir-scale faults at outcrop, however, shows that they often contain regions in which the fault displacement is partitioned between numerous fault segments. This segmentation can significantly influence cross-fault and along-fault flow paths, and therefore should not be ignored in either exploration or development modelling studies. Two classes of approach have been developed for representing three-dimensional fault zones in reservoir models: placing discrete fault zone components on the model faults and upscaling them to the resolution of the full-field flow simulation model ("geometrical upscaling"), or modelling variable properties within high resolution locally-refined grids embedded around each fault ("fault facies modelling"). This presentation discusses recent methodological advances in geometrical upscaling within the context of a newly-defined workflow that allows construction of stochastic models of the sub-seismic structure within reservoir faults, conditioned to the seismic interpretation and constrained empirically by the geological history of the fault.

Recent focused geological characterisation has resulted in a quantitative geometrical model in which the amount of fault segmentation present on a fault of a particular displacement is expressed as a function of three parameters related to the frequency, shape and integrity of intact and breached relay zones of different sizes. This parameterised conceptual model underlies FaultMaker - a tool for generating stochastic models of sub-seismic fault zone structure conditioned to the seismically resolved fault characteristics (e.g. Fig 1). The models contain a kinematically robust extrapolation to sub-seismic scales of the fault segmentation at the larger, seismically observable scale. The high resolution geomodels can either be used in a qualitative fashion to assess risks associated with reservoir compartmentation (in an appraisal or development context) or fault seal integrity (in an exploration context). Alternatively, in a reservoir production context, realisations can be input into geometrical upscaling algorithms to define neighbour and non-neighbour connection transmissibilities for production flow simulation modelling.

Geometrical upscaling is the process of calculating the transmissibility of three-dimensional flow paths through a fault zone, and representing these transmissibilities at the resolution of the full-field flow simulation model in which the fault is represented as a single surface. These flow paths can either be across the fault, or on a single side of the fault between stratigraphically distinct units, perhaps separated by an impermeable layer. The three kinds of geometrical up-scaling considered to date are compared. The original *template-based geometrical upscaling* involves the calculation of transmissibilities between components of a fine-scale model of the fault zone; followed by combination in series to define transmissibilities between grid-cells in the upscaled model; followed by combination in parallel to account for all possible flow paths between each pair of grid-cells. The method is inaccurate and inflexible.

In *flow-based geometrical upscaling* (e.g. Fig 2) the transmissibilities between each pair of grid-cells across or up a fault are back-calculated from a set of flow simulation models with different boundary conditions conducted on a fine-scale model of the fault zone. Fault membrane properties are included as transmissibility multipliers. The flow-based method is accurate and can be adapted to include two-phase as well as single-phase fault rock properties, but needs a cumbersome implementation including coupling to a flow simulator.

In the *threshold-based geometrical upscaling* method, possible flow-paths are identified using a connectivity algorithm within the cellular structure of the model, at a range of transmissibility cut-offs. A representative length and cross-sectional area of the flow path is estimated based on the three-dimensional geometry of the connected cluster of cells, and on the connection between the cluster and the upscaled cell locations. A transmissibility is calculated for each flow path as a function of the transmissibility cut-off value at which the flow path becomes open. The method does not aim to be particularly accurate, but instead is intended to capture an ensemble of up-scaled solutions that between them are representative of the behaviour of the range of possible sub-resolution fault zone structures that might be present in a statistical sense.

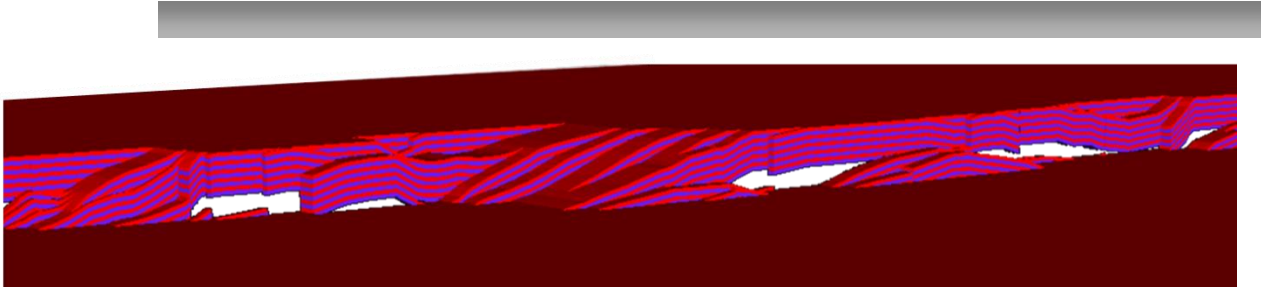


Figure 1. Vertically exaggerated view of a fault in a layered geomodel including significant quantities of stochastically-modelled sub-seismic displacement partitioning.

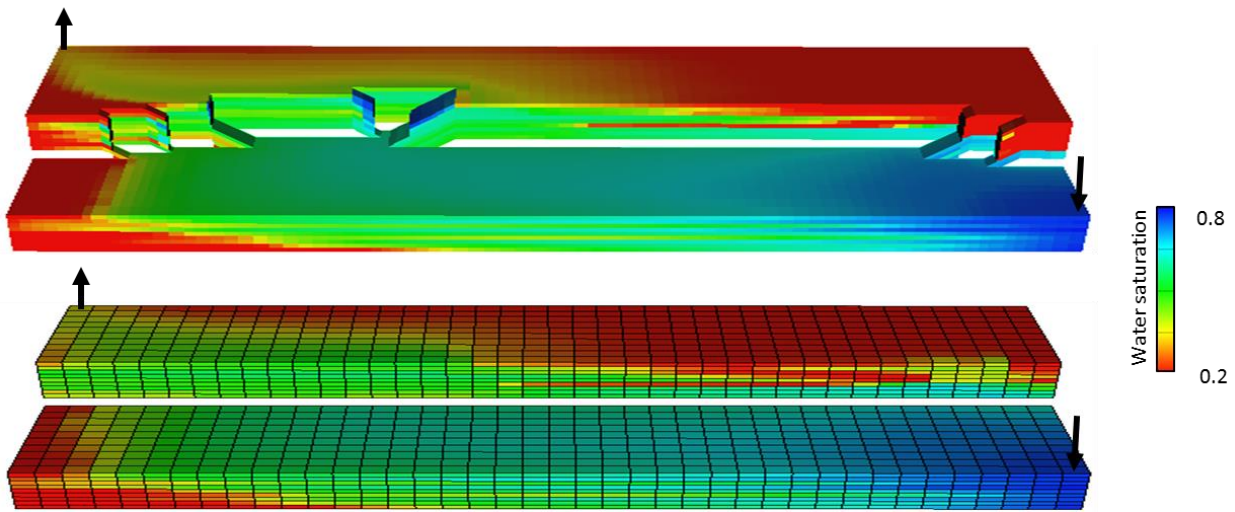


Figure 2. Explicit (top) and implicit (bottom) representations of small breached relay zones in flow simulation modelling, for a fault with a throw greater than the reservoir thickness. The models are coloured by water saturation at an equivalent moment during a water-flood between an injector and producer wells at opposite corners of the model (arrows). In the implicit model, flow-based geometrical upscaling was used to calculate across-fault and up-fault transmissibilities within the relay zones.



NOTES:

The impact of deformation bands in fault zones on permeability: an upscaling approach

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Cataclastic deformation bands are widely observed in the damage-zones around faults in high-porosity sandstones, with good examples from the UK in the Permo-Triassic sandstones on the Wirral (Cheshire) and in the Eden Valley (Cumbria). Deformation bands can occur in very large numbers and act as baffles to fluid flow, particularly when clustered together, reducing the quality of reservoirs for hydrocarbon production or for the storage of anthropogenic CO₂ emissions. The impact of deformation bands on the flow properties of a reservoir is difficult to quantify given their small thickness (~1 mm) and their permeability values which range to several orders of magnitude below that of the intact host-rock.

We use analytical and numerical upscaling techniques to estimate the overall reduction in the bulk permeability of a reservoir due to the presence of deformation bands. To upscale from millimetre-thick deformation bands to reservoirs tens of km in extent we utilise three sequential stages of modelling based on field data: 2 m cubes incorporating individual observations of deformation bands; an onshore cliff-section; and a 10 km square offshore reservoir model based on 3D seismic data and containing multiple faults with associated presumed damage zones. Our approach provides an estimate of the impact of deformation bands at the reservoir scale and incorporates uncertainty in assessing the number, distribution and permeability of deformation bands.

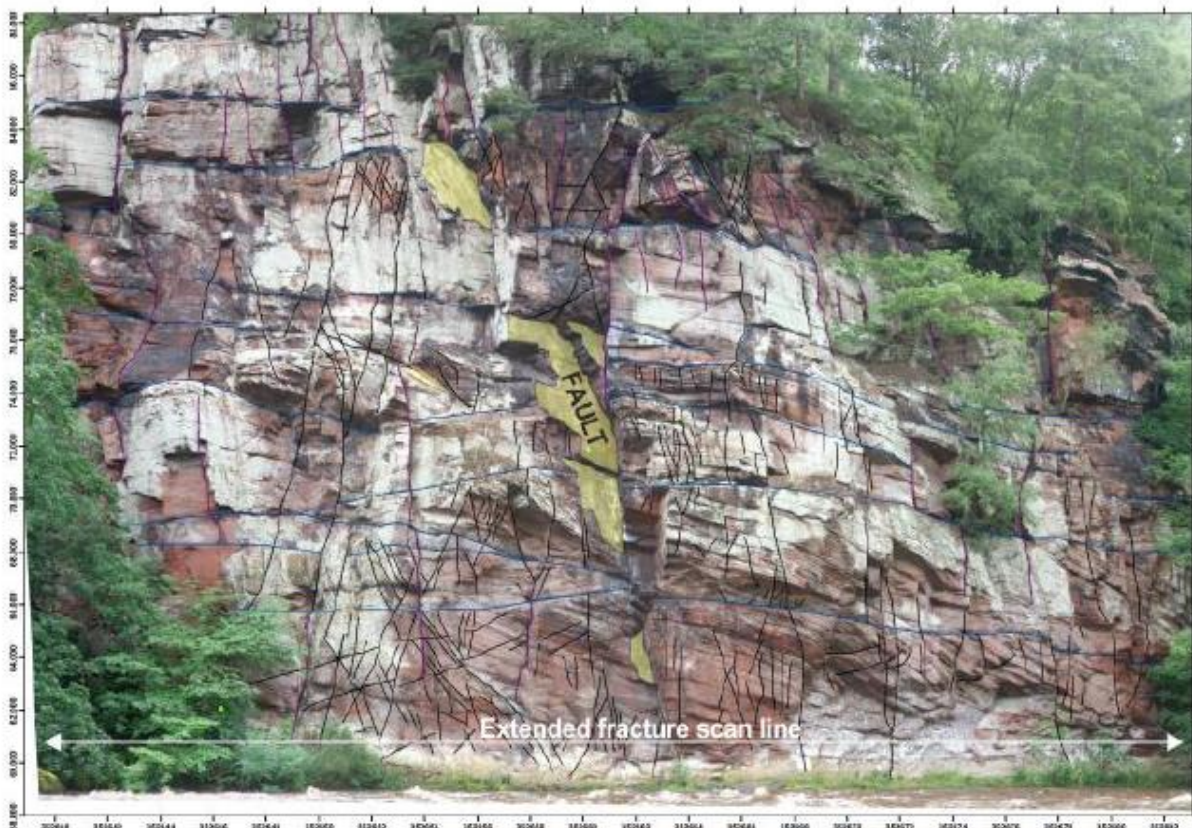


Figure 1: The cliff outcrop used to measure the number of deformation bands within 50 m of a fault. The three 2 m cube models were also built from data at this locality in the Eden Valley.

Observations and measurements of deformation bands at a field site on the Lazonby Estate in the Eden Valley were recorded. Observed localities showed low, medium and high density of deformation bands, representing increasing proximity to a fault, and based on these three models were built extending 2 m in each direction with a cell size of 1 cm. The permeability of deformation bands is difficult to measure given their small thickness. Micro-permeameter measurements suggested permeability values around 3 orders of magnitude lower than the host rock but actual values could be significantly lower. Single-phase numerical flow simulations of each model were completed with an

applied pressure gradient and an overall permeability calculated from Darcy's law for a range of deformation band and host rock permeability values.

A cliff outcrop at the field site (Figure 1) provided a good onshore analogue to the offshore Rotliegend reservoir beneath the North Sea. A scanline was delineated to provide data on the locations of the deformation bands and a laser scan was taken of the cliff. The number of deformation bands and their distance from a fault are uncertain parameters incorporating significant randomness. These will vary from site to site and even vertically up a cliff face. A Monte Carlo approach was used and multiple realisations of the cliff-scale model were constructed with the total amount of high, medium and low deformation band density zones (corresponding to the fine-scale models) varied according to site data from both field observations and available literature (see coloured lines in Figure 2). Analytical upscaling provided averaged permeability estimates for the entire damage zone over the range of assumed properties.

The full reservoir scale model was chosen to be as generic as possible but with properties based on a real portion of Rotliegend reservoir beneath the North Sea, imaged on 3D seismic data. The model extends 10 x 10 km laterally and incorporates faults every 3.5 km cutting across its entire width. The faults were initially assumed to be parallel and include a damage zone extending 30 m either side. Again, analytical upscaling was used to determine the average permeability of the reservoir in three directions (fault perpendicular horizontal, fault parallel horizontal and vertical).

The presence of deformation bands within fault damage-zones was shown to reduce overall reservoir permeability significantly (Figure 2). The strongest effects are on permeability perpendicular to the deformation bands (Figure 2a) where bands with permeability 4 orders of magnitude lower than the host rock can reduce the permeability of a reservoir perpendicular to the dominant fault direction by a factor of up to 100. Permeability reduction parallel to the faults and in the vertical direction was much less, typically up to about 10%.

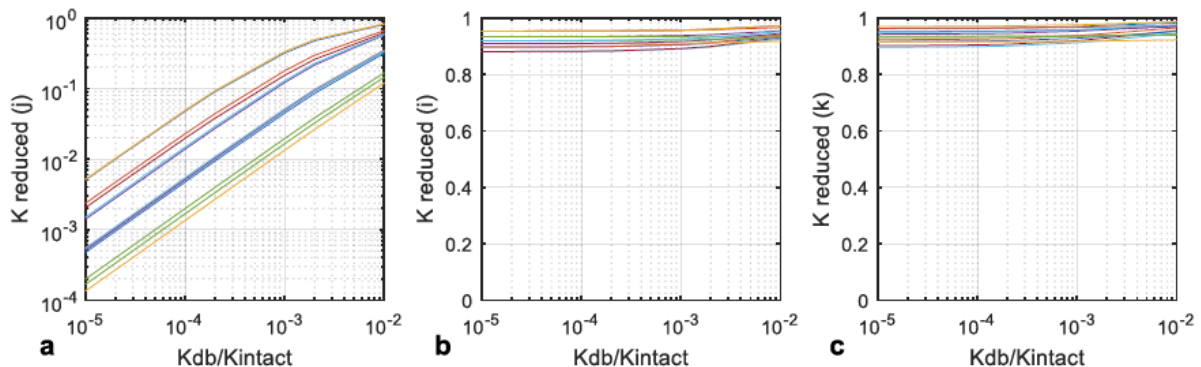


Figure 2: Overall reduction in permeability ($K_{reduced}$, ratio of unfractured host rock permeability to upscaled permeability) against the ratio of deformation band permeability to that of host rock (a) perpendicular to faults, (b) parallel to faults and (c) vertically. Coloured lines represent a range of cliff-scale models based on literature and field data.

This methodology provides an estimate of the impact on permeability that deformation bands in the damage zones of faults can have on a reservoir. It offers a means of assessing the impact of fault damage zones on the bulk permeability of a reservoir and highlights the importance of these potential sub-seismic flow barriers.



NOTES:

Friday 17th November 2017
Session Eight: Exploration & Production 1

KEYNOTE: Stochastic Trap Analysis Comparison of Efficiency of Juxtaposition and Shale Gouge Ratio Algorithms: A Global Review

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Exploration fault seal analysis of prospects is often focused on generating a probability of success. This risking considers sealing hydrocarbons against faults over geological periods of time. Typically, the risking is based on cross-fault juxtaposition and/or sealing shale development on the faults, on a single “best” technical model, commonly referred to as a deterministic model. Considerable work has been done by a number of workers to calibrate the sealing effect of fault rock, for example, the Shale Gouge Ratio (SGR) algorithm, to predict free water level. These calibrations involve back-calculating the seal potential from SGR and determining a resulting across fault pressure difference (AFPD) and or buoyancy pressure, to trap an observed free water level. Importantly, this back-fitting of SGR and AFPD has been conducted on single “best” technical models. In general, application of SGR methods on sealing across faults in prospects increases predicted column heights as it adds to columns calculated from juxtaposition analysis. Typically, large columns are generated and then discounted through geologic risk factors. If wells do not find the predicted columns, this is often “explained” by lack of charge or trap breach.

It is proposed that the fault and stratigraphic uncertainties are significant and need to be included in the modelling of fault seal risk and inferred column heights. A process of model validation will be presented in which observed free water levels are compared with the results of probabilistic models for both juxtaposition and SGR. Case studies from a wide range of basins globally show that probabilistic models can accurately predict free water levels (sub 10m accuracy) and identify leaking faults. Probabilistic models better predict free water levels incorporating uncertainties in a stochastic analysis typically yields smaller but much lower risk traps, rather than high risk traps based on overly optimistic calculations. Applying these models and methods to fault seal analysis will allow explorers to better define risks and rewards on prospects.



NOTES:

Using Trap Analysis to derive prospect-fill scenarios in fault-bounded traps: A Case Study from the Southern North Sea

Pete Bretan

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A key factor in the appraisal of a discovery is to establish the extent of the accumulation using prospect fill scenarios. Typically, only very simplistic fill scenarios are derived in which all faults are assumed to be sealing at reservoir-against-reservoir juxtapositions. In areas of complex faulting, such a simple approach can give rise to erroneous volume ranges and uncertainty risking which, in turn, can have serious economic implications for field development. Ignoring faults with sealing potential can often result in an underestimated prospect evaluation and potentially missed pay.

Traditional fault-seal analysis at the scale of a discovery typically involves constructing a single, best-case 3D fault model which is then populated with well data (e.g. Vshale logs) or inverted seismic data (e.g. Relative Acoustic Impedance). Numerous fault-plane diagrams are derived that show reservoir-against-reservoir juxtaposition, Shale Gouge Ratio (SGR) and hydrocarbon column height. Whilst such fault-plane diagrams derived using this deterministic approach are rich in detail, the information they contain is often interpreted in isolation removed from the 3D context of the prospect. This disconnect between fault-plane diagrams and the structural context has several important consequences: 1) a purely visual approach to evaluating fault-plane diagrams can be challenging especially for complex juxtapositions or for traps bounded by multiple intersecting faults; 2) it is time consuming to derive key results of the analysis, and 3) it is not feasible to undertake numerous sensitivity studies to evaluate variations in fluid densities or SGR to threshold pressure relationships.

This contribution describes an enhanced fault seal methodology, termed Trap Analysis that permits key results of a fault seal analysis (or sensitivity study) to be rapidly obtained for a fault-bounded prospect. Trap Analysis enriches the traditional fault seal analysis workflow by considering all faults that bound a trap as a single coherent structural element. It is only by interrogating all faults simultaneously can key information be derived (e.g. maximum column height in the fault-bounded trap supported by fault seal).

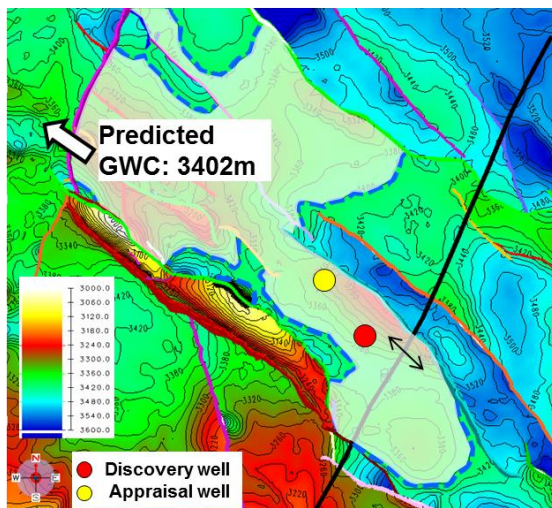
A case study from the Southern North Sea is used to illustrate the benefits of the Trap Analysis approach for deriving prospect fill scenarios. The Cobra discovery is located in the Sole Pit Basin in the Southern North Sea. A discovery well drilled in 1984 on a 3-way dip closure encountered a gas column with a gas-down-to of 3418m within a Permian reservoir. An appraisal well was drilled in 2008. Interpretation of reprocessed seismic data in 2013 together with detailed well analysis showed that the Free-Water-Level in the discovery well indicated a bigger structure than the 3-way dip closure could account for.

Faulting in the study area is dominated by NW/SE trending normal faults formed during the Mid to Late Jurassic extension. Burial depth at time of faulting was ca. 3400m. Some extensional faults have been inverted during the Late Cretaceous and Tertiary. The Cobra area is crossed by several NNE/SSW trending fault structures and lineaments, the latter only being evident on auto-tracked horizons and horizon surface attributes displays. The sealing potential of all faults within the Cobra area (NW/SE and NNE/SSW trending structures) was evaluated using the standard Shale Gouge Ratio (SGR) algorithm. Column heights were predicted using SGR to pressure relationships based on empirical studies from seismic interpretations (e.g. Yielding et al., 2010) and from laboratory analysis of core samples (e.g. Sperrevik et al., 2002).

The Yielding et al., (2010) and Sperrevik et al., (2002) relationships predict the deepest gas contact supported by fault seal at reservoir-against-reservoir juxtaposition to within 20m of the observed gas-down-to value. In addition, both methods predict almost the same depth for the deepest contact (3402m and 3396m respectively). This is an encouraging result as it implies that both methods are appropriate for predicting the hydrocarbon column height in the study area.

However, the SGR-pressure transformations used in the analysis predict different locations for potential across-fault leakage out of the prospect and also different sealing/non-sealing behaviour for the NNE trending lineaments. Figure 1 illustrates the impact that the predicted non-sealing (Fig 1a) or sealing (Fig 1b) NNE trending lineament has on the potential compartmentalisation of the accumulation.

a) Communication across Lineament



b) Lineament possible barrier to flow

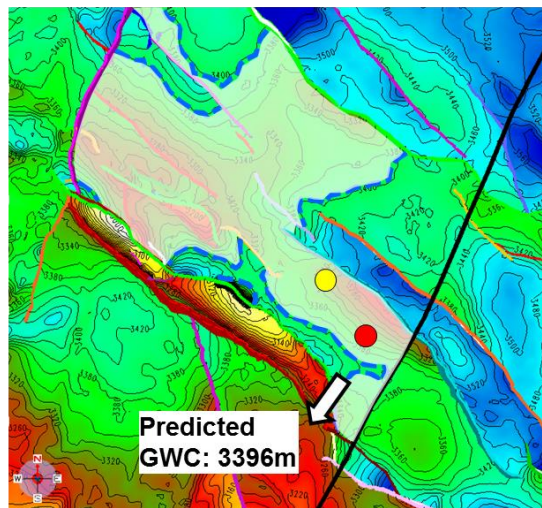


Figure 1: Top Reservoir depth map showing predicted fill (shaded), leak points out of the prospect and deepest hydrocarbon contact predicted using (a) Yielding et al., (2010) and (b) Sperrevik et al., (2002) relationships. Black line trending NNE is a lineament predicted to be non-sealing using the Yielding et al., (2010) transformation but sealing using the Sperrevik et al.,(2002) transformation leading to the possible compartmentalisation of the accumulation.

The case study outlined in this contribution illustrates the benefits of using Trap Analysis to quickly derive alternative prospect fill scenarios for a discovery. Considering all faults as a single structural element enables sensitivity studies to be routinely undertaken. Alternative fill scenarios help to improve the understanding of potential sealing behaviour of faults and the possible compartmentalisation of a prospect. This enables a more targeted appraisal programme, with associated risk, cost and time reductions. In the case of Cobra, Trap Analysis has de-risked substantial upside to a marginal discovery.



NOTES:

The application of existing fault-seal algorithms to fields in the greater Baram delta, NW Borneo

Arjan Brem

Sarawak Shell Bhd

In oil & gas exploration, being able to successfully predict the HC-column height in fault bounded blocks is a holy grail. The industry often uses Clay Smear or Shale Gouge Ratio (SGR) algorithms correlated with Hg-air entry pressure, to link to a maximum allowable HC-column by a fault in a trap. Such algorithms have been applied to and documented for various clastic basins across the world. Fault-bounded prospects and fields of the Miocene-Pliocene deltaic sediments in NW Borneo theoretically lend themselves for such correlations to be used. However, analyses show that some of the fields this setting – structural framework and stratigraphic uncertainties considered low – the publicly available clay smear correlations (e.g. Yielding et al, 2002; 2010) are underpredicting actual column heights, especially in areas of low SGR sand-on-sand juxtapositions. Although good practice dictates that for each basin the seal/leak threshold relationship to SGR should be empirically calibrated, the applicability of existing clay smear algorithms in NW Borneo is contested.

First, many of the fields have been affected by inversion tectonics, with the main bounding faults commonly being reactivated. Inversion may invalidate the SGR-method as the calculation only accounts for final strain (throw), not the total strain path. Especially in areas of the fault surrounding the 'null point', the calculated clay smear may be underestimating the degradation of porosity/permeability in the fault zone and therewith the capillary entry pressure.

Second, any clay smear function applies to permeability reduction due to clay content only, but does not incorporate effects of cataclasis. Observations from regional outcrops and cores show that these fault zones are commonly made up from a combination of deformation bands, cataclastic zones, and clay smeared zones. Published studies have demonstrated that cataclasis allows for permeability reductions of two to five-fold with respect to their host rocks, hence this deformational process should not be overlooked in a predictive approach. Conversely, quartz veins have not been observed, suggesting that clogging of fault zone pore space due to quartz cementation is not a governing factor.

Third, it is postulated that the present-day in-situ state of stress may also play a prominent role. The fields are located in the inverted part of the delta. Published experiments on laboratory samples of on suggest that an increase in confining pressure on core plugs shows a decrease in permeability. The decrease is more prominent in core plugs with lower initial permeability under the same confining stress, i.e. a fault rock compared to its host rock at the same depth. The effect of increased confining stress on increasing seal capacity of faults, has been identified before, but is usually captured as maximum depth of burial.

Work is ongoing to improve our understanding and predictability of the NW Borneo setting, focusing on the above mentioned parameters.



NOTES:

Modelling Shale Smear and its inclusion in Fault Seal Analysis

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Shale smears are considered to form an important component of fault rocks in faulted sand-shale sequences (Vrolijk et al., 2016). The smears form by entrainment and abrasion of the faulted shale into the high deformation fault core. Here this material may remain intact as discrete shale veneers (smears, *sensu strictu*), or it may disaggregate and mix with other fault rock components to generate a phyllosilicate framework fault rock (PFFR) or clay-rich gouge. Both the shale smear veneers and gouge/PFFR can contribute to the capillary sealing properties of a fault and enable hydrocarbons to be trapped even though cross-fault juxtapositions result in sand-sand connectivity. Predictive fault seal analysis uses various techniques to try and assess the impact of shale smears within a fault zone. Two of the more common published models employed to evaluate the shale content of the fault rock are:

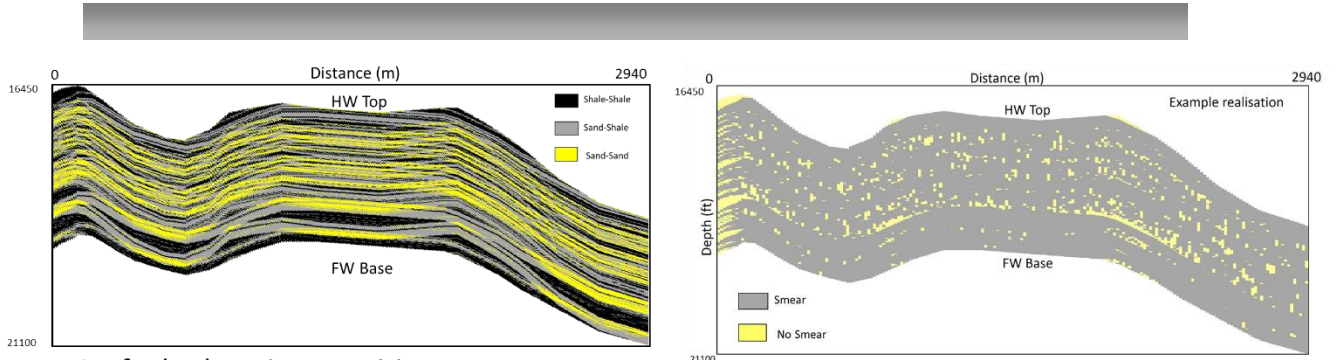
1. The Shale Gouge Ratio (SGR)
2. The Shale Smear Factor (SSF).

The Shale gouge ratio (SGR) is a proxy measure that is simply the thickness weighted average amount of shale within a section that has been displaced past a measurement point on a fault (Bretan et al 2003, Yielding et al., 2010). A higher SGR value indicates a more shale prone section and thus indirectly equates to the probable development of shale smears. Empirical observation suggests a SGR greater than 20% will yield a capillary seal. Shale smear prone faults are generally considered to have $SGR > 40\%$. The shale smear factor (SSF) is defined as the fault displacement divided by the shale thickness (Lindsay et al 1993). This can be summed for each shale layer that has been displaced past a measurement point. The key utility of the shale smear factor (SSF) is in the identification of a critical value (SSF_c) beyond which the smear is no longer intact. A breached or discontinuous smear creates holes in the smear envelope that may enable cross-fault fluid flow. The SSF with a constant value of SSF_c is currently incorporated into programs such as TrapTester and Petrel, assuming a mid-point smear break.

This talk will outline a geometric shale smear model that can be used to evaluate the potential impact of shale smears in a fault seal analysis (Grant, 2017). The model introduces granularity to the modelling of shale smears using the Shale Smear factor (SSF). Rather than apply a constant critical shale smear factor (SSF_c), the value of SSF when a smear breaks and becomes discontinuous, this new model allows SSF_c to vary both as a function of the clay content of the shale and also to vary probabilistically, the value of SSF_c drawn from a uniform population of values that represents the natural variability seen in outcrop and lab model datasets. This creates more variability in the smear catalogue for a faulted sand-shale sequence. A range of smear placement models are also evaluated and compared, including the random smear model outlined in the Probabilistic SSF approach of Childs et al (2007).

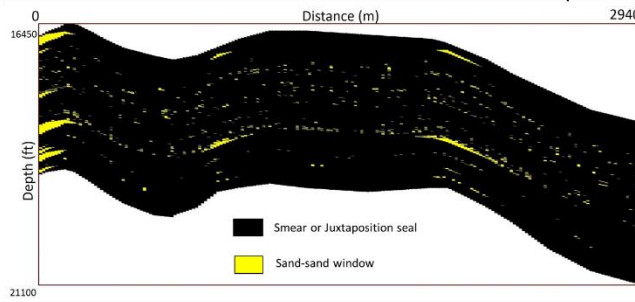
The model can be incorporated into 1D (Triangle) and 2D (fault plane mapping) approaches to evaluating fault seal. These developments will be described and examples given. It is now possible to map shale smears both more rigorously, and probabilistically, in fault seal analysis and to understand how they might affect a seal prediction. Calibration of the SSF_c remains key to developing a robust predictive model. This approach is particularly appropriate for use in clastic reservoirs at shallower burial depths where other capillary seal enhancing mechanisms such as cataclasis (grain size reduction) and/or cementation are less important. Results suggest that discrete shale smears are not necessarily an effective fault seal mechanism alone due to the persistent development of windows in the smear envelope (particularly in 2D). While the number of windows decreases with fault throw and the probability of effective fault seal increases, the depth to the first window in the hanging wall of the fault tends to shallow because smear dislocation increases with throw. This implies that in the absence of other seal mechanisms the fault, when it leaks by shale smear breach, leaks at a shallower depth below the hanging wall top at larger throws than for smaller throws. For a given stratigraphy there is a throw "sweet spot" range where fault seal capacity by smear appears to be at a maximum. This trend is contrary to that observed when SGR is used to characterise fault seal, as this property tends to increase as throw increases and more shale is incorporated into the fault zone, increasing the seal potential. Resolving this conundrum will be discussed.

Handling Fault Seals, Baffles, Barriers and Conduits



2D fault plane juxtaposition map

Smear Envelope Map (Random smear placement)



Combined Map showing residual windows where cross-fault connectivity may occur



NOTES:

Friday 17th November 2017
Session Nine: Exploration & Production 2

Invited Speaker: Smears, holes, SGR, and fault seal prediction

Graham Yielding

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When clays or shales are interbedded with sandstone or limestone reservoirs, they usually play a controlling role in the development of fault seal properties. For 20 years, fault seal has routinely been assessed in subsurface traps by using the Shale Gouge Ratio (SGR) algorithm. Although SGR is a simple average of wall-rock shale content, it was never intended as a precise description of complete grain-scale mixing in the fault gouge. Instead, it is an upscaled empirical measure which “represents, in a general way, the proportion of shale or clay that might be entrained in the fault zone by a variety of mechanisms”. Understanding and quantifying those mechanisms remains an ongoing challenge today.

The simplest expression of the problem is a 2D cross-section of a single faulted clay bed separating sands above and below. Early outcrop observations of this geometry have been supplemented by sandbox experiments of increasing sophistication. The shear strain of the clay bed can be expressed by the ratio of fault displacement to clay thickness, termed the Shale Smear Factor (SSF). Observations show that clay smears tend to be continuous in cross-section from footwall to hanging wall at low values of SSF, but become breached as displacement increases. The critical value (or range of values) of SSF at which this happens is dependent on the strength/brittleness of the clay/shale layer and also the confining stress under which fault displacement occurs. The likely position of the breach (hole), relative to the footwall and hanging wall cutoffs, seems to be variable, with mid-point, footwall and random breaching having been reported in different studies. Even when the smear is breached, the smear fragments remain in the fault plane as disconnected barriers to across-fault fluid flow. The proportion of fault trace covered by smear fragments decreases with increasing displacement, increasing SSF and decreasing SGR.

Whilst the above geometry is relatively well understood, significant complexities arise when extrapolating such findings to

- (i) the fault plane in 3D rather than just cross-section, and
- (ii) multiple clay beds rather than a single bed.

Recent sandbox experiments show that the “critical SSF” measured on cross-sections may be a poor measure of the overall continuity of a clay smear barrier – for example more than 90% of cross-sections may show smear breach but the corresponding proportion of holes (hole area fraction, or ‘HAF’) on the fault surface is only a little over 10%. The hole area fraction shows a statistical correspondence with both SSF and SGR. When multiple clay beds are involved in the faulting, the sealing process becomes much more efficient because holes in the smears from different beds are rarely aligned – as a result the effective hole area fraction becomes very small and cross-fault flow may depend on tortuous paths in the clay-poor parts of the fault rock.

Attempting to upscale these laboratory observations for fault seal prediction in the subsurface involves scale changes of 3-5 orders of magnitude. The relative sizes of the smear lengths and the reservoir beds, and the random placement of the smear fragments, may be critical in determining whether a particular fault-bound trap can hold a hydrocarbon column. The convolution of the stratigraphic architecture with the smear architecture may be simple or complex, and this is illustrated by example case studies from the Brent Province and Tertiary shallow-marine clastics. With multiple beds and stochastic smear breaching it is impossible to predict the smear holes deterministically - however, smear holes are more likely in areas of fault plane with lower SGR. Moreover, the non-smear parts of the fault-rock may themselves have a non-zero seal capacity, particularly when cataclasis and/or cementation have been significant. Two end-member behaviours can be recognized:

- (i) smear holes which directly control the OWC, providing an across-fault leak point at the *base* of the hydrocarbon column, and
- (ii) fault-rock leak points, which support an underlying column and may leak oil or gas from *within* the column.

The case studies provide some evidence for both end-members. As an empirically calibrated attribute, SGR provides a pragmatic probabilistic fault seal predictor in sand-shale sequences for this range of fault behaviour.



NOTES:

Application of temporal fault seal analysis

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In hydrocarbon provinces where maturation and migration occurred prior to fault reactivation, it is often informative to investigate the temporal variability in fault seal capacity. In this case study from New Zealand, we demonstrate an integrated workflow that combines fault seal analysis with kinematic sequential restoration. This approach allows the construction of lithological juxtaposition diagrams and the calculation of seal proxies at key time intervals during the development of a petroleum system. Understanding the change in the sealing capacity of faults through time can constrain the development of known hydrocarbon plays and help identify new exploration targets.

A sequential restoration aims to retro-deform a 3D model by accounting for the effects of: 1) physical compaction, 2) faulting and 3) folding. Restoration of these processes will reduce the magnitude of throw accommodated by a fault and change the geometry of that structure at depth. This will result in altered across-fault horizon configurations and, therefore, different palaeo-lithological juxtapositions. In addition, the restored geometries can be used to calculate sealing proxies, such as shale gouge ratio (SGR), allowing evaluation of potential membrane seals prior to subsequent fault reactivation.

In this study, the importance of temporal fault seal analysis is illustrated using the Cape Egmont Fault (CEF), located in the Southern Taranaki Basin, offshore New Zealand. The 60 km long fault, which currently accommodates up to 3.4 km of throw, underwent multiple phases of normal and reverse movement, recorded by time-constrained cross-fault growth packages. Reactivation of the CEF during the Miocene and Pliocene formed a low relief footwall structure which traps the Maui gas field, the largest hydrocarbon discovery in New Zealand. Previous work has demonstrated, that the Maui sub-basin, which is situated within the hanging wall of the CEF, contains source rocks which have been generating hydrocarbons for more than 20 Myr (Funnell et al., 2001; Reilly et al., 2016).

To investigate the potential for hydrocarbon charge from the Maui sub-basin, the CEF was restored to four intermediate time steps, from present day to 5.5 Ma. Characterisation of lithological juxtaposition and calculation of SGR was then performed at each time step, allowing the potential for migration in the present and past to be examined. Present-day analysis indicates that Eocene reservoirs are offset by more than 1.5 km, juxtaposing the charged footwall against late Miocene muds and marls and negating present-day cross-fault migration. In contrast, fault analysis at restored time intervals indicates that prior to ~3 Ma, the principal reservoir was self-juxtaposed. Calculated SGR values at these restored time-steps are less than 20%, indicating that the probability of a membrane seal at the reservoir interval was low (Fig. 1). This suggests that the CEF may have formed a viable migration pathway before 3 Ma.

In circumstances where fault movement has occurred since hydrocarbon expulsion, it is necessary to account for changes in fault throw and geometry. This allows temporal variations in hydrocarbon migration and trapping mechanisms to be more accurately predicted



NOTES:

Evaluating risk of depletion of an Exploration Prospect from a neighbouring field and its impact on potential future drilling

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Predicting fluid flow across faults is a critical part in production forecasting, as well as the number of wells to be drilled in a hydrocarbon-rich exploration area. A fault can be a transmitter of, or a barrier to, fluid flow and pressure communication. The typical question in the industry is whether the fault is sealing or leaking and what impact that may have on the economics of the project. Therefore, to assess the economic viability of an exploration target, fault zone structure and transmissibility must be evaluated correctly. Understanding fault-seal behaviour is an imperative part of the reservoir development strategy. Fault-seal depends on juxtaposition, fault rock (membrane seal), geo-history and fluid properties. This requires undertaking fault-seal analysis and assessing the risk of sealing and non-sealing potential of faults. Generally, hydrocarbon leakage takes place when the buoyancy pressure (pressure difference between the water and hydrocarbon phases) exceeds displacement or capillary entry pressure (pressure required for hydrocarbons to enter and pass through the largest interconnected pore throat in the seal). This paper aims to assess the sealing or leaking nature of the faults of interest and reflect on its wider implication on the project.

The field we are looking at is Edradour, located West of Shetlands. Edradour is a gas Condensate discovery drilled in 2010 by well 206/04-02. The reservoir is encountered at a depth of ~ -3400m TVDSS, whilst water depth is ~300m. 206/04-02 encountered 43m gross section of Lower Cretaceous deep water turbidite sandstones; average porosity is good, Net to Gross is high and permeabilities range into the multiple hundreds of mD. Edradour is a stratigraphic trap formed by the onlap of a thick sequence of Cretaceous turbidite sands onto a rotated Jurassic/Triassic fault block. Top and base seal is provided by Calcite cemented turbidite sands, with cementation formed by in situ bioclastic material. The Field is also considered a DHI anomaly, whereby the presence of Gas Condensate generates a bright amplitude, although no water leg has been drilled to date. Prospect A which is on the west side of Edradour, is a downthrown extension of Edradour, displaying similar seismic characteristics to the original discovery. It is therefore considered a viable exploration prospect.

A new 3D seismic survey was acquired, processed and interpreted (as shown by the diagram below) with a static model built by the geoscientist working on the field. The model went through a series of refinements, to make it geologically robust, specifically around the faults itself. The key pre-drill risk is considered to be up-dip fault seal, with seismic interpretation indicating that sand to sand juxtaposition may be possible across the main fault zone. Hydrocarbon production from Edradour is due to commence soon and a business decision will be made whether to drill on the west side based on whether there is communication between the Edradour and prospect A.

The methodology used to assess the sealing or leaking nature of the faults that impacts Edradour and prospect A uses the relationship between Across Fault pressure differential (AFPD) and Shale gouge ratio (SGR). This relationship is compared against the fault seal envelope derived from literature to deduce whether the fault is sealing or leaking. Simulation models based on the same geological model were performed. Pressure, water and gas saturation change over time in the simulation model helped in validating the conclusion on sealing nature of the fault. Fault transmissibility and its associated production profiles are assessed on different cases using a reservoir simulation package. This paper provides a workflow which could be used to assess the fault-seal. The result and recommendations from this work aims to help the business assess the economic viability and help to make a sound decision on drilling a new well.

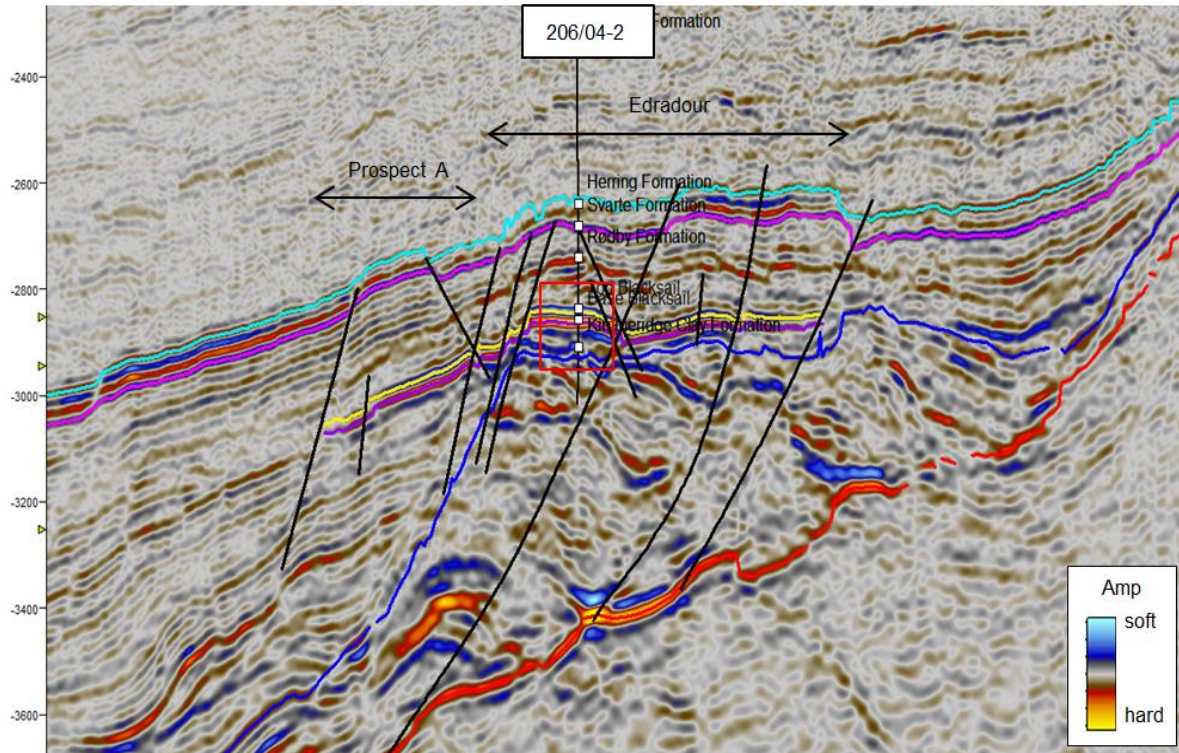


Figure: Interpreted 3D seismic.



NOTES:

KEYNOTE: A Decade of Progress and Regress in Flow Simulation of Faulted Reservoirs

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Over a decade has passed since the Geological Society of London conference on 'Structurally Complex Reservoirs'. Many of the comments and recommendations regarding flow simulation of faulted reservoirs discussed at that conference (e.g., Fisher and Jolley, 2007 in Geol. Soc. London Spec. Publication 292) remain pertinent today. The comments below echo comments from that conference, and reflect the imperfect progress toward construction of complete and rigorous flow simulation models that limit the loss of geological information common in those models. Some of the uneven progress is driven by commercial considerations that spawn cycle time reduction efforts, many of which result in simplifications to representations of complex geological settings. These money and time saving efforts also curtail scenario and sensitivity testing, which can lead to unpleasant surprises deep into the development and production.

Expensive, reactionary decisions commonly follow observation of reservoir production performance indicators that point toward an alleged negative impact of fault flow behavior (i.e., transmissibility). Commonly cited indicators include unexpected rapid production rate decline, early water break-through, poor injectivity, poor sweep efficiency, and 4D seismic response. When these reservoir behaviors are observed, responses typically result in negative commercial impact, whether it is drilling additional unplanned wells, acquiring additional (4D) seismic surveys, reducing estimated ultimate recovery, de-booking volumes, or even selling an asset. Proactive considerations and measures that impact our understanding of likely fault behavior on reservoir production can reduce the occurrence of reactionary responses. Proactive effort can (should) begin as early as the exploration discovery phase and continue through development planning to the hand-off to production.

The first order issue to defining the impact of faults on reservoir behavior is that of uncertainty in the characterization of the reservoir architecture and its representation in geologic and flow simulation models. The uncertainty derives from data density and quality, the ability and experience of project personnel, and the effort put forth (time allotted). The impact of the uncertainty on reservoir performance modeling (simulation) can be, to an extent, mitigated by thoughtful, early identification of alternative scenarios, understanding the impact of those scenarios on fluid flow, and data collection relevant to the evaluation of those scenarios. This can start during the exploration phase, even before the discovery well is drilled. If exploration geoscientists, working with development geologists and engineers, recognize the importance of faults to development planning then both well path and data collection plans can be aligned to provide information that satisfies exploration criteria (e.g., is there a volume of interest) and early stages of the development planning. This might include designing a side-track well to test reservoir segmentation, collecting more pressure data than normal (particularly aquifer pressure), targeted reservoir and seal sampling for permeability testing, collecting fluid samples, and running DST or similar production tests to establish early information on drainage radius.

The development stage of a field presents an interesting conundrum in that appraisal and early development drilling typically adds subsurface information that improves detail and reduces uncertainty, but, almost contemporaneously, the simplifications that inevitably accompany geologic modeling, and subsequent upscaling to flow simulation models, blur the detail and increase uncertainty. Best results are obtained when the project geoscientists provide detailed, high quality interpretation and analytical products that recognize the importance of fault network, reservoir distribution, and pressure and fluids details. Once completed, the geologic interpretation goes to geologic modeling where geologists should provide guidance during construction of the model – what should be retained in the models, what may be simplified, what can be omitted from the models. It is during this stage that geologically-based fault transmissibilities are estimated, at a relatively fine scale, for eventual upscaling and inclusion as fault transmissibility multipliers in the flow simulation models. Fault transmissibilities commonly are established by calculating the capillary and permeability parameters of modeled fault zone materials for faults that may segment a reservoir. Critically, the continuity and areal coverage of the fault zone materials and the distribution of holes through the fault zone materials often provide better estimates of fault transmissibility than calculation of fault zone material properties. To complicate matters, non-fault reservoir properties, such as shale partings, impart flow tortuosity that can be misinterpreted as a fault transmissibility problem. During modeling and simulation both fault and depositional

features should be captured in scenarios and included in sensitivity testing. Well design, completion strategy, and pressure support plans then can be designed with the best information possible, and mitigations planned for a range of potential reservoir performance outcomes.

Without doubt our ability to understand and predict the flow behavior of faults in the subsurface, and to incorporate that into flow simulations, has improved over the last decade. The question we now face is how do we bring that improved knowledge and capability to bear on our development and production planning? How do we introduce technical rigor in the face of budgetary, time, and personnel constraints? It is unlikely that we will, with any regularity be able to build and run flow simulation models at the level of detail and sensitivity testing that we would like. Thus, careful consideration of what really matters, what really has the largest impact on the simulations needs to be worked out well in advance of the modeling effort.



NOTES:

Permeability of faults in shale rich sequences: evaluating the risk of upwards leakage along faults of fracking fluids

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There has been a marked increase in exploration and production of oil and gas from reservoirs formed by shale dominated sequences. In addition, shale dominated top seals and shale rich overburdens are important for the long term integrity of carbon capture and storage schemes. Faults are frequently suggested as major leakage pathways connecting shale gas reservoirs to near surface fresh water aquifers. To evaluate the potential risk of fracking fluids or formation brines from shale gas reservoirs polluting freshwater aquifers we need to understand the permeability of faults in shale rich sequences. We have analysed the published literature on faults in shale rich sequences, and pooled permeability measurements of fault rocks from these faults. The dataset (figure 1a) shows that the permeability of these fault rocks spans a large range, from 10^{-9} to 10^4 mD. In the study we explore the controlling parameters, e.g. the type of fault rock, the composition and the confining pressure during measurement.

Considering this wide range of potential permeabilities we have performed basic hydrological modelling to assess the sensitivity of leakage along fault zones from shale gas reservoirs to fault permeability. We model single-phase fluid flow using MODFLOW. The models represent an absolute worst case scenario of operational failure, where the excess fracking pressure is maintained in the fracking stage. Upwards fluid flow is driven by both this excess pressure and by the buoyancy of non-saline fracking fluids compared to the surrounding reservoir brines. Permeability of the overburden is estimated using a well log for the Bowland basin and constrained by published permeability values. The permeability of the fault zone is varied in different scenarios, based on the permeability values from the dataset.

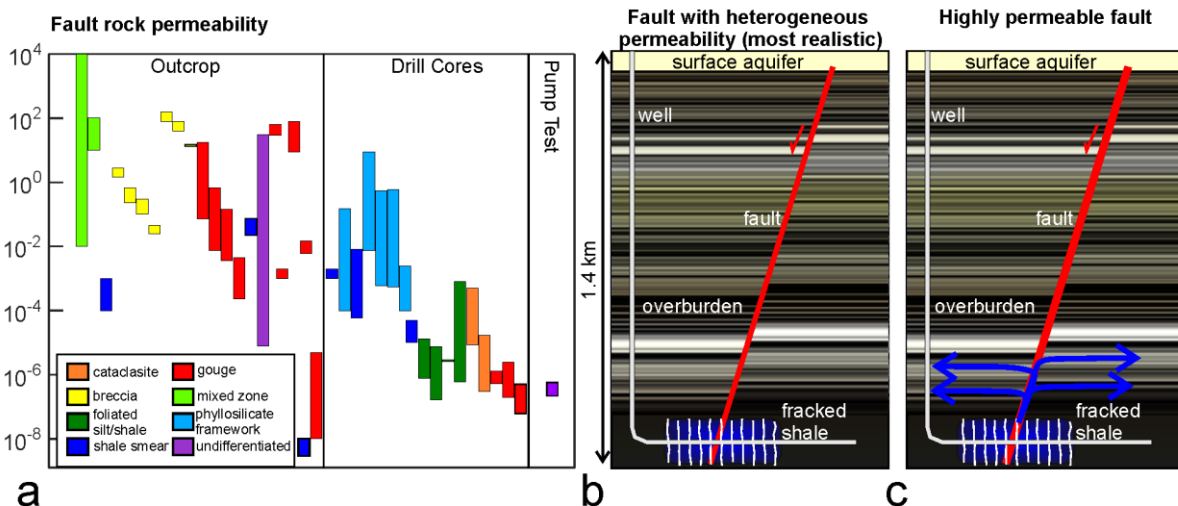
For the most realistic scenario, which involves a fault zone where the permeability is varied with depth (figure 1b), with the values constrained to the dataset, no fluids escape the reservoir. Within 5 years the salinity of the fluids increases to the value of the surrounding brines, removing buoyancy as a driver for fluid flow.

In the high permeability scenario, the permeability corresponds to the highest values in the dataset, and this high permeability is applied continuously from the reservoir interval to the surface. For this scenario fracking fluids escape the reservoir but do not travel upwards for more than 170m above the shale reservoir (figure 1c). Instead the fluids are captured by saline aquifers in the overburden just above the reservoir. Here the fluids are trapped in very slow deep flow cycles (millions of years).

The modelling shows that neither salinity difference based buoyancy or injection pressures are sufficient to drive fracking fluids to freshwater aquifers. These results assume an extreme scenario of operational failure. Under normal operational conditions, gas will have been produced from the reservoir, reducing reservoir pressure and drawing flow inwards from the surrounding rocks rather than driving flow away from it.

Acknowledgements

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NOTES:

High Resolution Borehole-Imaging of Faults Architecture and Scaling in Carbonate and Siliciclastic Shales, Saudi Arabia

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Faults architecture and scaling have been predominantly based on outcrop observations and applied to subsurface faults prediction. Recent advances in logging while drilling (LWD) borehole imaging have presented a paradigm shift that enables a high resolution subsurface characterization of faults. Such images have been obtained and calibrated with cores on a regional scale to detect and characterize tectonic faults in two basins, which are targets for unconventional exploration in Saudi Arabia. The effort has been driven by the need to detect and determine the accurate location of faults, and their scale and architecture to optimize borehole design and completion for unconventional prospect evaluation.

This paper demonstrates two contrasting unconventional reservoirs in terms of their degree of faulting as observed at high resolution in borehole images; a densely fractured and faulted siliceous Silurian Qusaiba Shale, and a sparsely fractured and faulted Jurassic Tuwaiq Mountain Formation, in two different basins in the Arabian platform, Saudi Arabia.

The Tuwaiq Mountain Formation is characterized by a mild degree of tectonic deformation manifested by low density mesofractures and comprise mainly dispersed extension and some shear fractures/ faults with no evidence of significant faults zones. In the Qusaiba Shale, tectonic fracturing is significant with a total of 1341 faults observed in horizontal wells, and 36 faults diagnosed in vertical wells. In terms of their spatial distribution the faults include two categories. The first comprises 44% of the faults and occurs as dispersed or non-clustered individual. The second category makes up 56% of the faults, which are clustered into several scores of relatively narrow zones, each zone encompassing a few to numerous faults and joints separated from other zones by comparatively wide intervals of sporadically faulted country rock.

In the Qusaiba, 29% of fault zones show clear evidence of fault rock development, and some of these are complex in terms of having multi-layers of fault rocks within the fault zone, including: fault core (FC) with principal slip zones (PSZ), and outer fault-damage zones (FDZ), where a less significant part of the deformation is accommodated. The Qusaiba faults displacement (D), thickness (T) and length (L) vary by several orders of magnitude. They are analyzed and used to develop scaling parameters and compared with published empirical outcrop-based relationships in other rock types and provinces in the world.

The mild tectonic fracturing and the lack of major faulting in the Tuwaiq Mountain Formation have contributed to the preservation of highly pressured unconventional reservoir. The dispersed mesofractures act as weakness zones and thus contribute positively to the nucleation and subsequent propagation of hydrofractures during stimulation, without the risks associated with pressure depletion usually observed in highly permeable large fault zones. The challenge faced in the Qusaiba Formation where faulting is more developed is to delineate any major, potentially permeable fault zones and isolate them while designing hydrofracturing. An additional aspect being considered for the major faults observed in the Qusaiba is their potential sealing quality and trapping mechanism of gas in the underlying Ordovician Sarah sandstone pay zones. An additional aspect being considered for the major faults observed in the Qusaiba is their potential sealing quality and trapping mechanism of gas in the underlying Ordovician Sarah sandstones, which are also targets of exploration in the same basin.



NOTES:

Data sampling and the accuracy of fault models based on T/D and T/Z data

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High-quality three-dimensional (3D) seismic and outcrop data are used to review the effects of data sampling on the accuracy of throw-distance (T/D) and throw-depth (T/Z) data used in fault analyses. Our approach results from the recent publication of interpretation methods, based on seismic data, that could under specific circumstances (poor data quality, coarse data grids) underestimate the effect of data sampling on fault growth analyses and interpretations. In this talk, we test how reliable are estimates of coherent vs. isolated fault models when data sampling is well above the seismic inline/cross-line spacing. We interpreted a wide number of faults on high-quality, high-resolution data from SE Brazil (line spacing of 12.5 metres, vertical sampling of seismic data of 4 ms) to show that the accuracy of T/D and T/Z data is strongly dependent on the sampling methodology (i.e. spacing) adopted in structural models. We describe data collected for four types of faults with distinct geometries, lengths and relative ages on high-quality seismic sections.

Our analysis shows that T-D plots based on information acquired every inline/crossline (12.5 m/12.5 m in our data set) reveal the most accurate method to identify fault segments. T-D plots undertaken every 3, 5, 10 and 20 inlines/crosslines were produced to calculate the module error between the area of T-D plots and the horizontal axis of every inline/crossline and every n inlines/crosslines, following the formula:

$$\varepsilon_i = (A_1 - A_n) / A_1.$$

In this equation, ε_i represents the module error, A_1 represents the area calculated every inline/crossline, A_n represents the area calculated every n inlines or crosslines.

Our results indicate that:

1 - Data accuracy is lost on T/D plots when error margins (ε_i) are larger than 5%-8% (Figure 1). This means, in practice, that T/D and T/Z curves will become smoother and featureless if sample spacing is too large, thus overlooking the presence of fault segments complying with 'fault-linkage' models. This also means that interpreters will be biased towards the identification of 'constant-length' or 'coherent' models to the detriment of 'isolated' fault geometries, a caveat that can be only limited by the use of detailed structural maps in the recognition of distinct segments. We suggest a Sampling Space/Fault Length (or S/F) ratio below 5% as a minimum criterion to recognise, and obtain, reliable T/D and T/Z data. This results, for our study area, in a minimum of 18 measurements for a linked fault array.

2 - In our study area in SE Brazil data accuracy is also significantly lost when T/D and T/Z curves show less than 80% overlap between decimated profiles and data obtained every inline/crossline, i.e. our data shows that there should be a minimum of 80% overlap in T/D and T/Z data between 'raw' line-by-line measurements and decimated samples. In practice, this means that in SE Brazil one can measure T/D data every 3 lines (37.5 m) without exceeding the 80% ratio above. More specifically, a spacing of five (5) inlines/crosslines (52.5 m) is still viable for faults with only one or 2 fault segments. With more than two fault segments in a single structure, one should measure spacing every three (3) inlines/crosslines (37.5 m). However, this same spacing is different depending on the S/F ratio above, and on the resolution of seismic data used. If the 80% overlap criterion is not followed, fault segment linkages will not be accurately observed.

3 - Module error decreases with increasing fault segment length. However, when average fault segment length excess 1000 m, module error is statistically more predictable, with an error of 3%, 4%, 8%, 10% separately for a measure spacing of every 3, 5, 10, 20 inlines/crosslines.

In summary, when using seismic volumes with inline/crossline spacing higher than 12.5 m, interpreters will be working close to the ε_i limits calculated here, and to the 80% overlap necessary to correctly interpret T/D and T/Z measurements. This means, in practice, that measurements should be obtained every single inline/cross-line in these same volumes. The opposite happens when interpreting high-resolution seismic volumes with inline spacing below 12.5 metres, as T/D and T/Z resolution will be higher than normal for Industry data. If interpreters disregard

these sampling relationships they will: a) systematically underestimate fault linkage (or isolated) growth models, b) cluster data when compiling log-log plots, with scaling relationships being subsequently spread through larger areas to form distributions that are not 100% reliable. These caveats have clear consequences to the interpretation of fault models, and induce errors in subsequent estimates of fault damage zones, fault growth histories and regional structural evolution(s).

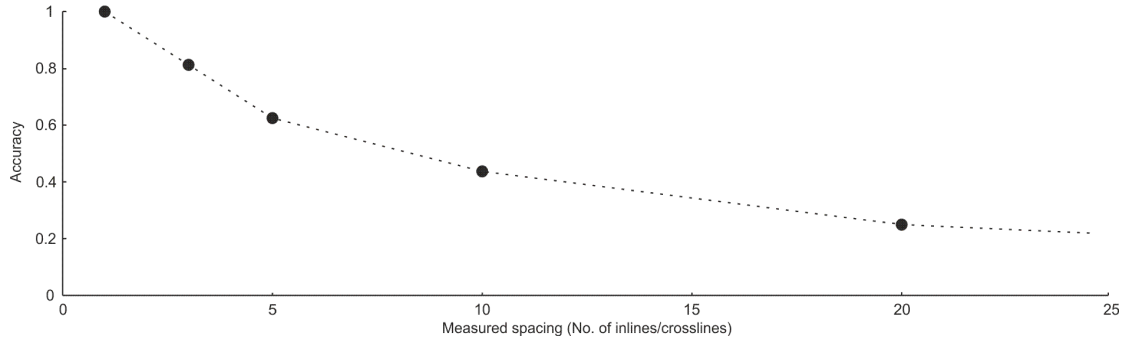


Figure 1

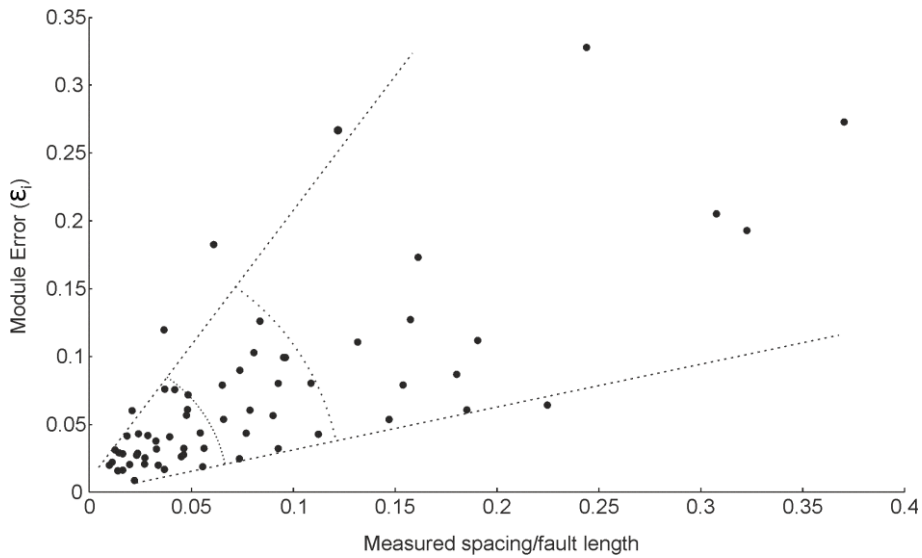


Figure 2

Poster Presentation Abstracts

Predicting properties of faults in sand-shale sequences: case studies from the Rotliegend, Dutch Southern North Sea area

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Understanding fault sealing and permeability is key for evaluating reservoir compartmentalization, structural trap integrity and hydrocarbon migration pathways. Existing fault seal evaluation tools (e.g. SGR, SSF) are only reliable in conditional circumstances and do not usually quantify their inherent levels of uncertainty. Ongoing research within the fault sealing group at the Department of Civil and Environmental Engineering, University of Strathclyde, has allowed to build up a large dataset of fault zone properties and tools to analyze and understand their effect on fluid flow. Based on these data, UoS researchers have developed a workflow that aims to evaluate fault sealing by evaluating the different geological processes and the likely fault architectures that they will produce for a geological setting.

By incorporating fault architecture, industry workflows for fault sealing and permeability analysis can be significantly improved.

This was recognized by EBN, who are non-operating partner in many on- and offshore exploration and production licenses in the Netherlands, including the very prolific gas fields hosted in Permian and Triassic sand-shale sequences. Many of their mapped prospects carry a fault sealing risk, and from a significant proportion of their producing gas field portfolio it has been established that ultimate recovery is lagging behind due to various aspects of fault sealing (juxtaposition sealing, clay smearing, cataclasis) [4]. Within the current E&P environment in the Netherlands, with aging infrastructure, and many gas fields in their mid-late field life, it is generally perceived this requires more focused attention across the various license boundaries.

A collaborative project between EBN and the University of Strathclyde was raised with the objective to identify if the process-based fault seal identification established by the UoS, which is currently based on outcrop data, could be applicable to predicting fault sealing properties in the deeper subsurface as well. This project is carried out by firstly building a catalogue of show-case proven examples illustrating the various aspects of fault sealing, including, but not limited to, faults acting as a barrier or baffle to pressure communication and/or hydrocarbon flow over the geological and/or production timescale, fault collapse and juxtaposition sealing (Fig 1). The current map is based on a short in-house review of the current field and prospect database of EBN, but the catalogue is expected to grow based on planned inventory.

Secondly, selected show case examples from this catalogue, in particular from Permian a/o Triassic sand-shale sequences, are or will be subject to more detailed review of the subsurface conditions. The collection of key parameters such as burial depth, host rock clay content, sand and shale bed thickness, fault geometry etc will allow for comparing fault rock type and associated sealing potential between the outcrop based fault characterization, and more commonly used predictors such as SGR. That should lead to a better understanding of the flow capacity through and across faults in relation to fault architecture and surrounding host rock properties. Current fault seal analysis tools in particular focusing on clay smearing depend largely upon published calibrations to e.g. shallow marine sand-shale sequences from the Brent province or laboratory measurements not necessarily honoring the properties and conditions of reservoirs in Permian and Triassic mixed fluvial/aeolian deposits.

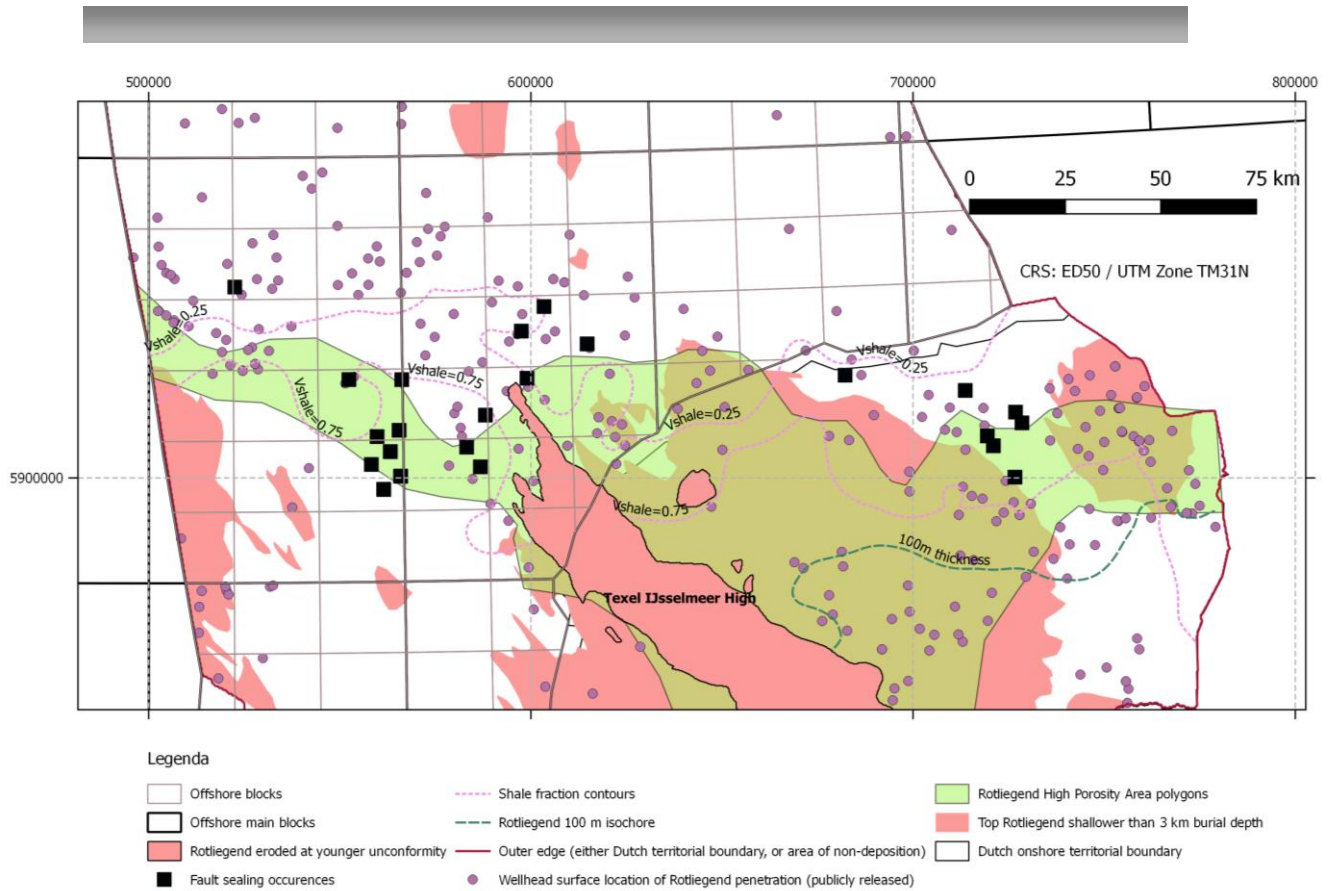


Figure 4: Basemap of the so-called “Featheredge” area, an east-west extending belt where the Upper Rotliegend depositional system changes from sand prone, mixed fluvial and aeolian deposits in the South, to a claystone rich playa environment in the North. Dotted lines represent iso-average Vshale ratio lines (0.25 contour), yellow filled polygon represents an area with elevated average porosity values, the dashed line (southeast corner) represents an isochore south of which the Upper Rotliegend sequence is less than 100 m thick, the grey filled polygons illustrate areas where present day burial depth of the top of the Rotliegend is less than 3 km (which is taken as a proxy for domains where the Rotliegend is at temperatures less than circa 90°C). Block symbols represent (anonymized) area/fields/structures where fault sealing aspects have been demonstrated to play a key role for reservoir compartmentalization, structural trap integrity and/or hydrocarbon migration. Well symbols represent wells which drilled through or reached the Upper Rotliegend, and have been publicly released (5 years after TD date).

It is expected that during the planned Fault Seal Conference early, notional observations and conclusions with respect to types and conditions of fault sealing can be shared resulting from the first case studies under review.

EBN, and in particular their operating partners, would benefit from this project to better understand compartmentalization and potentially to better assess risks of mapped leads and prospects, to improve exploration drilling success rates, to design more efficient (cheaper) development concepts and/or plans to improve ultimate recovery.

Quantifying the effect of core plug edge effects on porosity and permeability under uniaxial and triaxial loading conditions

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Since Hawkes and Mellor (1970) it has been recognised that uneven stress distributions occur within a core plug during loading in the laboratory (Figure 1). These stress distributions occur due to edge effects generated by the interface between the loading platen and the rock sample. Although these effects can be minimised by following ISRM standards of sample preparation and test conditions, the effect cannot be fully removed.

While these edge effects are recognised in stress, the impact that the varying stress distribution has on the fabric and microstructure of the sample is less well known. Critically, these effects are overlooked when taking bulk petrophysical property measurements – porosity and permeability – from core plugs during or after a stress test. Bulk property measurements are averaged along the length of the core plug and as such may not be representative of the true variation in these properties that can be found along the length of the plug. This could result in inaccurate values for these properties being reported. If the stress is focussed in certain parts of the sample leading to inelastic deformation in these areas, it could be expected that a similar variation in porosity or permeability would also be present in those areas.

An accurate understanding of porosity and permeability is vital for many engineering applications (oil & gas exploration, geothermal, hydraulic fracking, fault system modelling, earthquake source processes) as they form a basis for many modelling applications and inform how stressed rocks behave within faulted and fractured regions.

Here we analyse permeability along the length of stressed cores to determine if the irregular stress distribution as modelled by Hawkes & Mellor (1970) manifests itself as variations in the permeability and porosity. We examine these effects in samples of two different lithologies (low porosity and permeability granite and high porosity and permeability sandstone) taken to 90% of their failure strength under both triaxial and uniaxial loading conditions, to examine the impact of both loading and lithology.

Fifteen 25 mm diameter core plugs of each lithology were prepared with a length to diameter ratio of 2.5, according to ISRM standards. Each core was pre-characterised for bulk gas porosity (helium) and permeability (nitrogen). Eight cores of each lithology were taken to failure under axial compression at three different confining pressures to determine the ultimate failure strength of the samples under these varying stress conditions. Four samples were failed uniaxially at 0 MPa confining pressure ($\sigma_1 > \sigma_2 = \sigma_3 = 0$). Two were failed at 25 MPa confining pressure (conventional triaxial; $\sigma_1 > \sigma_2 = \sigma_3$) and two at 50 MPa confining pressure. Acoustic emission detection was also utilised to determine damage onset in each test.

Using the ultimate failure strength data, the stress at 90% of ultimate failure was determined. At this level of stress, inelastic deformation in the form of microcracking has been induced into the sample as evidenced by the generation of acoustic emissions. Subsequently six samples (two at each confining pressure) were subjected to 90% of the failure strength to induce inelastic deformation (microcracking) into the core plugs.

To examine the variation in permeability and porosity along the core plug length, the plugs are serially sectioned (Figure 2) into eight segments with porosity and permeability data acquired for each segment. In total, thirty porosity and permeability measurements are acquired for each sample.

The variation in porosity and permeability along the length of the stressed cores is compared to a non-stressed sample that has undergone the same serially segmented sample analysis.

The results of this study can be used to understand how porosity and permeability vary along the length of a core that has undergone stress, and has implications for how bulk porosity and permeability data acquired for stressed samples must be contextualised with respect to the way stress is distributed within the sample.

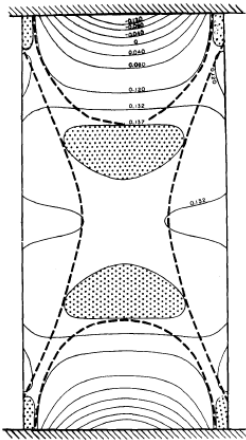


Figure 6

After Hawkes & Mellor (1970) showing stress distribution within a sample undergoing uniaxial compression. Shaded areas highlight the most critically stressed zones where deformation is likely to be focussed. Broken lines indicate where the sample is most likely to fail.

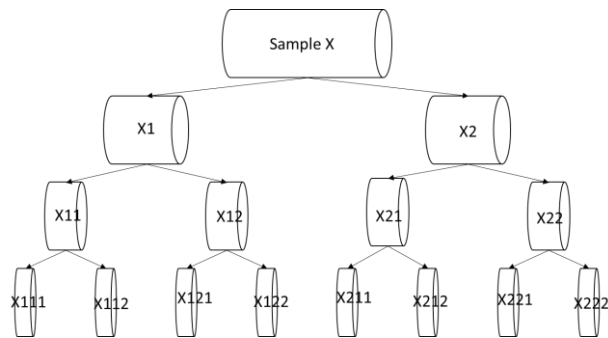


Figure 5

Serial sectioning methodology for analysing along length variations in porosity and permeability. At each cut, porosity and permeability analysis is performed resulting in 30 measurements per sample.

References

Hawkes, I., & Mellor, M. (1970). Uniaxial testing in rock mechanics laboratories. *Engineering Geology*, 4(3), 179-285.

Variations in porosity values by gas permeoporosimeter and digital methods in rocks affected by deformation bands

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³CENPES / Petrobras S.A

The study of petrophysical properties, such as porosity and permeability, are of great relevance when one wishes to understand the oil reservoir and to assimilate the migration and accumulation of fluids as well as fluid flow. The objective of the present work is to quantify the results obtained from computational petrophysical analysis and by means of conventional analysis, gas permeoporosimeter, in rocks affected by deformation bands (DB), and to identify an influence of DB in the variation of porosity. For this comparative analysis, samples from the Rio do Peixe Basin, northeastern Brazil, were used. The samples consist of plugs composed of coarse sandstones and conglomerates strongly affected by DB. The plugs collected were 1.5 inches in diameter and about 5 centimeters, which were oven dried for 24 hours under a constant temperature of 80 ° C, so that the actual value of the void spaces is measured when the nitrogen gas expands and does not interfere with weight when samples are weighed in precision electronic balance. Measurements of its dimensions (diameter and length) were carried out with a digital caliper to calculate the total volume. For the measurements of the porosity of Rio do Peixe Basin rocks, the UltraPorPerm 500® equipment, manufactured by Corelab, and was used. By means of the gaseous expansion porosimetry method, and with the aid of a matrix cup, the volume of grains of the sample was measured. As the weight of the sample corresponds to the weight of this solid phase, the grain density was determined. From the measured volume of the sample, the volume of grains was subtracted and the volume of voids in the sample was obtained and, therefore, the porosity was calculated. Moreover, thin sections were prepared on the same samples from regions of interest that contained both the DB and the intact rock. Image analysis was carried out on these digital images so as to extract the pore networks and then, the porosity of these regions was calculated. As a result, it is sought to understand the degree of variation in porosity values for each method, helping geologists and engineers to quantify the degree of porosity of rocks, as well as trying to understand which positives and negatives for each method used and their reliability. Partial results indicate that DB are significantly reducing porosity. The gas permeoporosimeter method provides a complete notion of the porosity of the rock, while thin sections show values of certain regions of the sample. This effect becomes costly when one wants to calculate the total porosity of the rock, but it becomes a good tool to understand the variation of the porosity inside and outside the DB.

Keywords: Deformation bands; Porosity in fault zone.

Exploring the influence of fracture pattern attributes on fluid flow in a fractured reservoir analogue

David Healy, Matthew Belshaw & Antonio Filippi

Rock Physics & Geomechanics Laboratory, School of Geosciences, University of Aberdeen, Aberdeen

Fractured – and faulted – rocks constitute some of the most prolific hydrocarbon reservoirs in the world. The fracture network provides essential porosity for reserves and permeability for production. It is therefore crucial to understand these fracture patterns and how variations in fracture pattern attributes affect fluid flow through the reservoir. Many fractures in the subsurface are below current imaging resolution; therefore effective, quantitative characterisation of fracture networks can only be achieved through outcrop studies. This poster shows an example from a Carboniferous limestone outcrop at Spireslack (Ayrshire, Scotland). We mapped the outcrop surface (in total approx. 500 x 35 m) using UAV (drone) imagery and then quantified the fracture pattern attributes using FracPaQ, an open source toolbox written in MATLAB™. These 2D fracture networks are then up-scaled and transformed into 3D geomodels using Petrel™ for fluid flow simulations. We explore the relationships between the quantified fracture pattern attributes and the fluid flow history for decadal duration production histories.

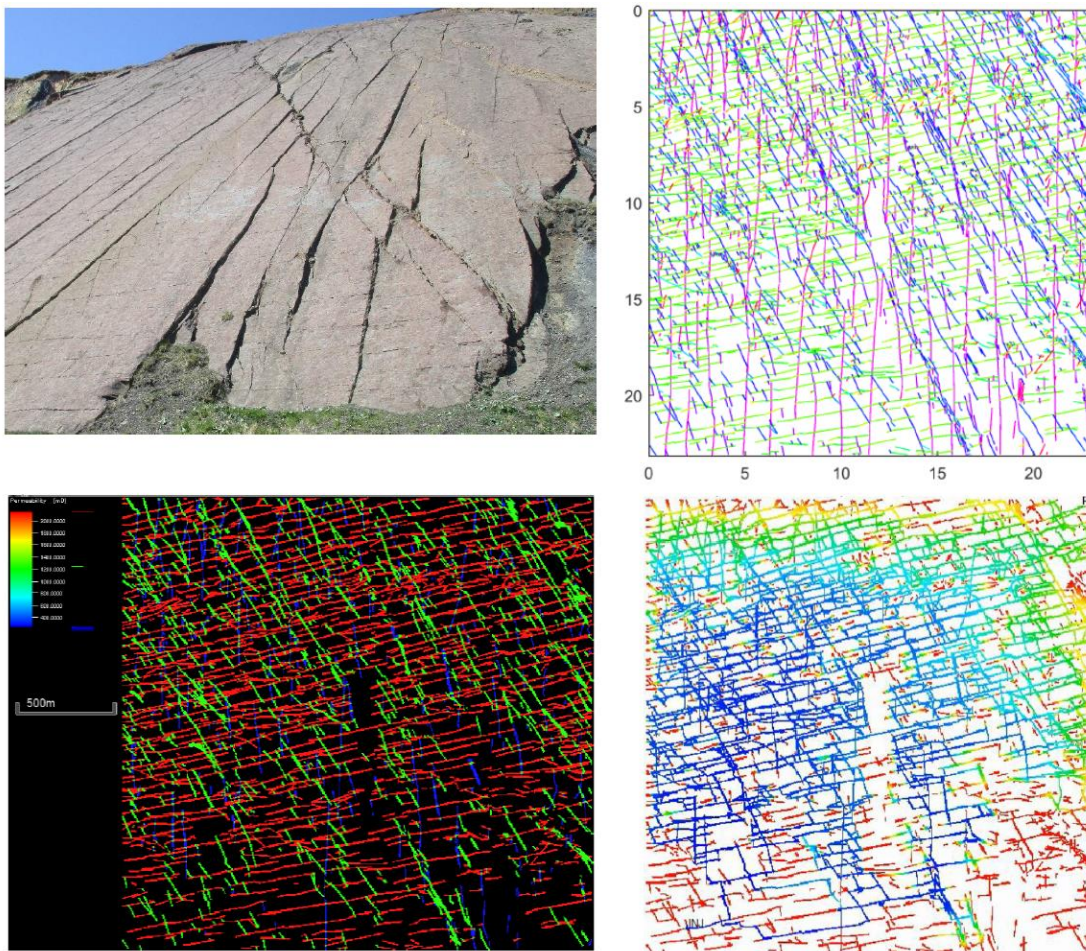


Figure 1. Example images showing the workflow for the limestone analogue. Top left shows the outcrop, with a limestone bedding plane dipping about 35° on the northern limb of a major East-West trending syncline. Faults, joints and veins are all present. Top right shows a single output from FracPaQ, with fracture segments colour-coded by strike to facilitate their sub-division into sets. Bottom left shows a map view of a 3D model in Petrel™, with fracture sets colour-coded by their assigned permeability values. Bottom right shows the results of a flow simulation with a producer located in the NE corner and injector in the SW corner, with the colour denoting oil saturation (red high; blue low) at P&A.

By quantifying the fracture pattern in FracPaQ, we found that:

- fracture intensity and density both decrease away from the bounding faults
- fracture lengths appear to show no obvious trend with proximity to the fault or with orientation

- I:Y:X connectivity remains roughly consistent across the outcrop; however, total connections do show a trend, increasing significantly towards the faults
- spatial heterogeneity in the orientation patterns were found, with an axial set and its conjugate pair observed across the outcrop; a further, commonly mineralised set, observed in the damage zone; and a final set observed in the centre of the outcrop, believed to be due to doming of the outcrop
- the predicted permeability ellipses, created from outcrop fracture data and using the crack tensor approach, were found to replicate what was observed from the flow models

The findings of this study show that well placement with respect to the fracture network can have significant ramifications on production data – either cumulative production or, in the case of simulations using producer-injector pairs, time to water breakthrough. In the case of this tight limestone analogue, optimal production was achieved with producer-injector pairs aligned parallel to the bounding fault zones, and perpendicular to the major fold axis. Outside the fault damage zones, the bulk permeability of the fracture network is greater perpendicular to the bounding faults and parallel to the syncline axis. Even though fault parallel tight (mineralised) fractures reduced flow, the overall flow perpendicular to the bounding faults was still strong. Increased fracture connectivity close to the fault reduced time to water breakthrough, ultimately causing inferior production values. By integrating quantified fracture pattern data from outcrop analogues and FracPaQ with flow simulations in Petrel™ we can develop a better empirical – and therefore predictive – understanding of the relationships between fracture pattern attributes and fluid flow in the subsurface.

Anisotropic pore fabrics in faulted porous sandstones

Natalie Farrell, David Healy, Eimhear Sheehan & John Millett

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The fabric of pores in sedimentary rocks around fault zones can be subject to significant modification. Knowledge of how pore fabrics vary during and after faulting is important for understanding how rocks transmit fluids around fault zones, and can help to predict whether faults will act as a seal or a conduit to flow. Previous studies modelling fluid flow have produced large datasets detailing pore networks of fractures – but little or no pore fabric information has been quantified from volumetrically significant intergranular porosity. In granular rocks like sandstones, where intergranular pores make up 98% of porosity, this must be addressed.

This poster describes pore fabrics quantified from two outcrops of normally faulted sandstone. The porosity and the size, shape and geometry of pores were quantified from core plugs and thin sections. Results were mapped within a framework of the faults to better illustrate how these datasets may be used to improve understanding of fluid flow around fault zones. Results from a mature, quartz-rich arenite (Hopeman Sandstone, Moray Firth, Scotland) show a change in pore fabric from pores oriented horizontally and parallel to laminations to pores oriented parallel to σ_1 . Pore fabrics quantified from a clay-rich, quartz sub-arkose (North Scapa Sandstone, Orkney Mainland) changed from moderate aspect ratio pores with no preferred orientation, to high aspect ratio pores oriented dominantly parallel to the fault surface. Permeabilities measured on corresponding core plugs showed anisotropy of permeability with maximum permeability oriented down fault dip around both faults (Fig 1).

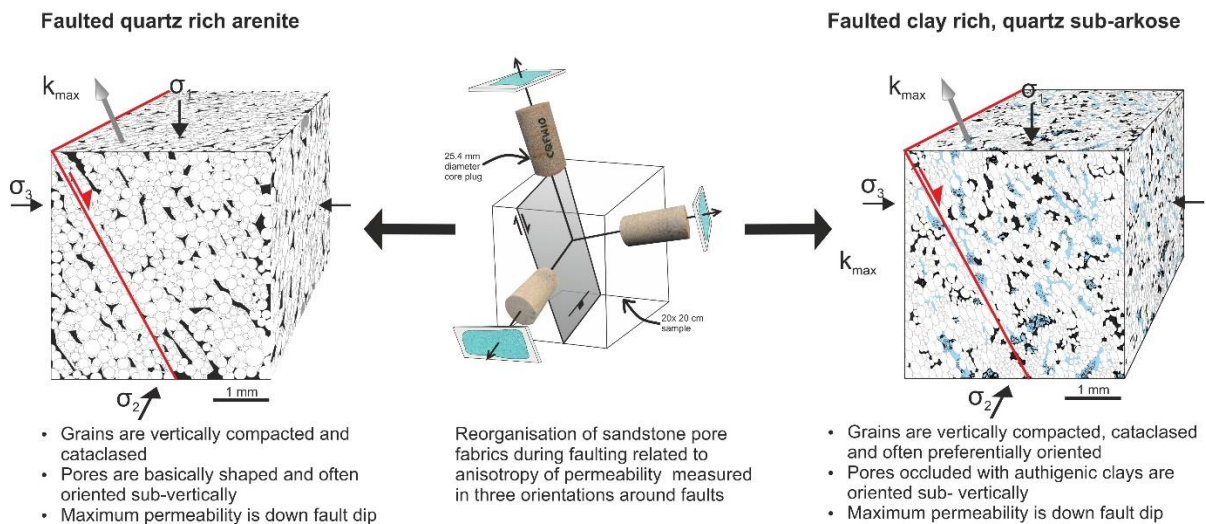


Figure 1. Schematic diagrams summarizing the effects of normal faulting on pore fabrics and permeabilities of porous sandstones.

The methodologies used to quantify microstructures from faulted sandstones have also been applied in a study on fluid flow in vesicular basalts from volcanic reservoirs. Results from this ongoing research show that the complexity of individual pores (vesicles) impacts the magnitude of permeability in undeformed rocks, therefore fluid flow patterns in faulted volcanic reservoirs also need to be researched.

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

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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.

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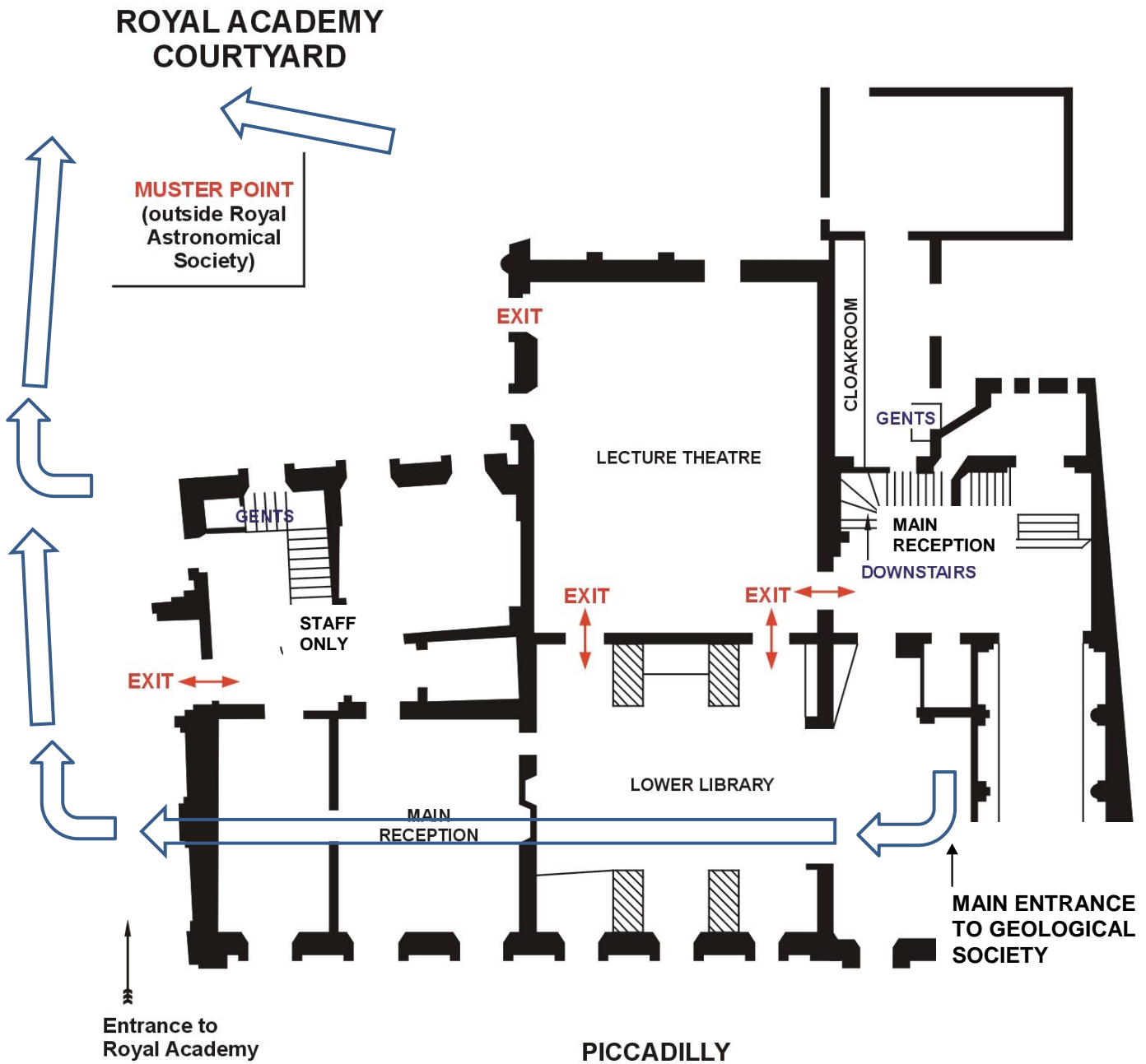
Facilities

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





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Call for Abstracts – Deadline: 23 Feb 2018

Eastern Mediterranean – An emerging major petroleum province

29-30 May 2018

The Geological Society, Burlington House, Piccadilly, London

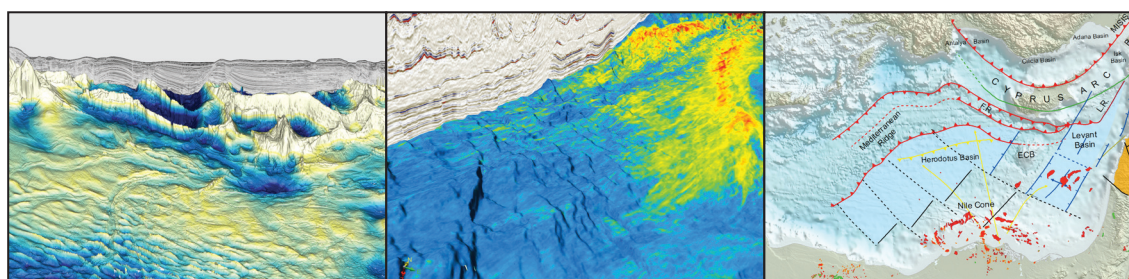


Image courtesy of Chevron

Image courtesy of PGS

Convenor:

Iain Brown
PGS

The objective of the conference is to enhance technical understanding of the status of key plays in this geologically complex region

In recent years the Eastern Mediterranean region has witnessed growing interest from international energy companies. Substantial gas reserves have been found in Egypt's Nile Delta Basin and in the Mediterranean coastal areas since 1995, and in more recent times Noble Energy has discovered a series of substantial gas fields off the Israeli coast. Several countries have been announcing licensing rounds in recent years.

A key objective of the meeting is to seek a strong set of papers to highlight in greater depth recent discoveries such as those of the prolific Pliocene Nile Delta province and the more recent ENI Zohr supergiant carbonate discovery and the successful clastic plays in the Levant Basin. Results from Totals current drilling campaign in Cyprus Blk 11 will also drive interest in the region.

The conference will review exploration activity, as well as challenges to a better understanding of the geology in the eastern Mediterranean, including seismic (and other data) acquisition and imaging. Key geological issues for understanding subsurface risk in the area will be addressed, including but not limited to

- Geodynamic Evolution
- Pre-salt plays including carbonate build-ups
- Source rock distribution and maturity
- The importance of regional seismic and refraction data
- Sediment provenance studies
- Reservoir quality and reservoir characterisation
- Potential of deeper plays and possibilities for oil.

Call for Abstracts:

Please submit abstract contribution to sarah.woodcock@geolsoc.org.uk by 23 Feb 2018.

For further information please contact:

Sarah Woodcock, The Geological Society, Burlington House, Piccadilly, London W1J 0BG. T: 020 7434 9944

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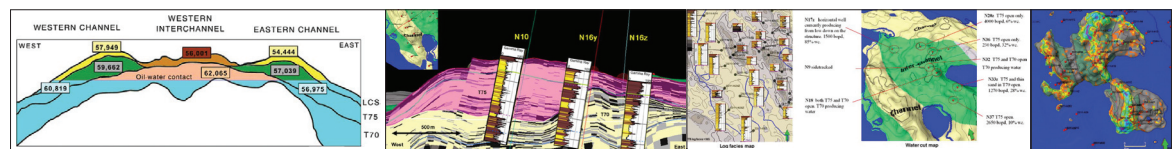
Al Tucker
Brent Asset Manager,
Shell

Call for Abstracts – Deadline 15 December 2017

Advances in Production Geoscience as an enabler for maximising economic recovery and ensuring a future for the UKCS

5-7 June 2018

Robert Gordon University, Aberdeen



Out of adversity comes opportunity. A significant change is required in the North Sea petroleum industry to keep it profitable and growing, and geoscience has the opportunity to lead the way in delivering this change. New plays, fields, technologies and alliances are required in order to increase recovery and reduce the cost of delivering hydrocarbons. In 2014 the Maximising Economic Recovery UK report suggested that 12-24bn barrels of oil equivalent remained to be produced from the North Sea. This conference aims to show how geoscience is helping to develop and recover as much of this remaining hydrocarbon as possible. It will showcase the range of solutions maximize economic recovery from the UKCS.

Specific themed sessions may include:

- Near Field Exploration
- New field developments
- Short radius sidetracks
- Infill drilling
- Production from secondary reservoirs
- The value of surveillance
- Existing infrastructure - hosts for new opportunities, making it last longer, novel maintenance, alternative uses (wind/CO₂ disposal)
- Shallow gas (fuel source) and water (for injection)
- Novel drilling technology as an enabler for difficult geology
- Exploiting difficult fluids
- Use of new technology or first application of technology to the UKCS
- Enhanced Oil and Gas recovery
- Adding value from co-produced fluids
- Decommissioning

The focus of the meeting will be on Geoscience, Reservoir Engineering and Petrophysics with the recognition that successful integration across the subsurface and surface disciplines is at the heart of a successful shift in future fate of the UKCS.

Call for Abstracts:

Please submit paper contribution to abstracts@geolsoc.org.uk and copied to caroline.gill@shell.com by 15 December 2017.

For further information please contact:

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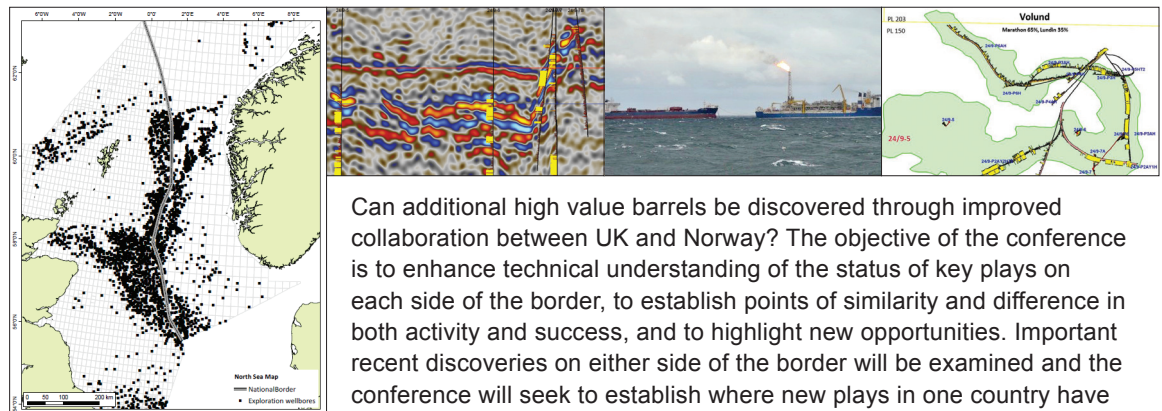
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Registration Open

Cross-border Exploration between UK & Norway – Comparisons, Contrasts and Collaborations

27-28 November 2017

The Geological Society, Burlington House, Piccadilly, London



North Sea Map
National Border
Exploration wells

Can additional high value barrels be discovered through improved collaboration between UK and Norway? The objective of the conference is to enhance technical understanding of the status of key plays on each side of the border, to establish points of similarity and difference in both activity and success, and to highlight new opportunities. Important recent discoveries on either side of the border will be examined and the conference will seek to establish where new plays in one country have not yet been understood or exploited across the border. Key note presentations will be made by leading figures from both Norway and UK.

This two day international conference will bring together explorationists from UK, Norway and other European countries with the following themes:

- Play opening discoveries as yet unexploited cross border
- Differences in how competence is organised and technology adopted
- Examples of specific play knowledge being exploited cross border
- Challenges on median line including data continuity and differences in nomenclature
- How to build a geology-without-borders view
- Issues for service industry
- Differences in exploration performance
- Danish and Dutch (and other) cross border examples
- Impact of regulatory and fiscal frameworks

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