Fracture and in-situ stress characterization of hydrocarbon reservoirs: definitions and introduction

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Fracture and in-situ stress characterization is fast-evolving as an essential part of characterizing hydrocarbon reserviors. In this book, the Geological Society presents a selection of sixteen chapters that demonstrate the tools, methods, analysis, interpretation and application of this subject. These are of great interest to researchers and scientists in the industry and academia. This chapter includes definitions pertinent to the subject of the book and gives an overview of the papers, classified into seven major themes according to the nature of the studies.

Definitions

Fractures are defined here as all discontinuities that occur in rocks due to brittle/semi-brittle deformation.

Natural fractures are those related to natural deformation of the rock. They include faults, cracks, joints, veins and stylolites.

Induced fractures are those induced artificially, e.g. by core handling, coring, drilling, fluid injection etc.

In-situ *stresses* are the current-day natural stresses present in the earth's crust. They are the result of a few components :

I *Gravitational stresses* due to the weight of the overburden.

II *Current tectonic stresses* related to present-day tectonic forces such as those resulting from the active collision of the Arabian and the Eurasian continents in the Arabian Gulf region.

III *Remnant/residual stresses* locked in the rock during past episodes of tectonic and gravitational stresses.

Fracture characterization is the science that deals with the detection (whether fractures exist?), diagnosis (identification of natural vs induced and type of each), and quantification of fractures (single fracture properties such as orientation, aperture, fault offset and length, and fracture population properties such as number of sets, orientation of each set, density etc.). Fracture characterization is a multi-disciplinary subject that integrates multi-tools and multi-scale observations like microscopic, borehole images, cores and 3D seismic data.

In-situ stress characterization is the science of determining the orientation and estimating the relative and absolute magnitudes of the three principal *in-situ* stresses (maximum, intermediate and mimimum, in-situ stresses referred to as σ_1, σ_2 and σ_3 respectively). This is done using an integrated suite of data like borehole images, borehole logs, extended leakoff tests, hydrofracturing tests and active seismicity analysis. In addition, using a cartesian system relative to earth surface, the stresses are also referred to as: maximum horizontal stress (σ_H) , minimum horizontal stress (σ_h) and vertical stress (σ_V).

Fractures play an important role in hydrocarbon reservoirs. They can impact permeability and porosity and thence reservoir performance. This is becoming more apparent with the advancement of technology and the shifting of frontiers to deeper and tighter reservoirs, in increasingly high temperature/high pressure environments. Therefore the need for fracture characterization is no longer limited to classical fractured reservoirs (in which fractures are the main source of permeability). Deep, tighter reservoirs rely on fractures as a source of porosity too. In addition, reservoirs with high matrix porosity and permeability can show negative symptoms related to un-wanted high permeability in fracture zones.

In both fractured and non-fractured reservoirs in-situ stresses can impact reservoir properties (porosity and permeability) and reservoir performance. In addition these stresses play an important role in issues of borehole stability, productivity and injectivity. Therefore, there is a need to characterize these stresses and model their

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impact on reservoir properties and performance. This has led to the emergence of a new concept to reservoir characterization: *geomechanical characterization*. This accounts for the stress-sensitivity of reservoirs (i.e. the changes in reservoir petrophysics and performance as a function of in-situ stresses).

The current volume

This volume stems from the Petroleum Group meeting on Fracture and *In-Situ* Stress Characterisation of Hydrocarbon Reservoirs, convened by the author at the Geological Society, Burlington House, London, 21–29 June, 1999. The current volume includes sixteen chapters that fall broadly into seven themes according to scale of observation, tools, and subject.

Borehole-scale characterization

In this theme three papers are presented with diverse objectives and level of data integration. Until recently it was always assumed that in a fractured rock mass, the most effective fluid conduits are fractures that parallel the maximum in-situ stress and are perpendicular to the minimum in-situ stress. The hypothesis behind this is that these fractures have the lowest normal stresses across them and therefore attain the maximum hydraulic apertures. However more recent work led to a major revision in this concept. In addition to fractures that are subjected to current-day tensile regime, fractures that are orientated such that they are subjected to both shear and tensile stresses can be critical fluid coduits, depending on the ratio of shear to normal stress and associated dilation. This dilation results in a significant increase in fracture hydraulic aperture and permeability. It is now accepted that critically sheared fractures (i.e. those close to frictional failure in the current-day stress field) serve as conduits for fluid flow.

The first chapter by S. F. Rogers and C. J. Evans demonstrates, through a case study from Sellafield in the UK, how the critical stress technique was successfully applied for predicting zones of enhanced fracture-permeability at the well scale. Difficulties for implementing the technique on a wider, field-scale are discussed. Although the study was not done for hydrocarbon reservoirs, it is of direct application to reservoir characterization.

In the second chapter Sneha K. Chanchani, Mark D. Zoback and Colleen Barton present a case study of hydrocarbon transport along active faults and production-related stress changes in the Monterey Formation, California. They studied the Antelope Shale, a low permeability siliceous shale hydrocarbon reservoir in the Buena Vista Hills field in the southern San Joaquin Valley to determine the influence of the stress state on the relative hydraulic conductivity of the fractures and faults. Because production has both lowered reservoir pressure and the horizontal stresses, it was necessary to 'restore' the reservoir stress state to initial conditions in order to identify correctly the most highly productive intervals. This analysis demonstrates that prior to production, faults in the reservoir were active in a transitional reverse/strike-slip faulting stress state, consistent with regional tectonics. Initial production rates in the field were 2000 bopd, principally from intervals where critically stressed faults were encountered.

In addition to predicting fracture permeability and its stress sensitivity, discussed above, fracture porosity assessment is another challenging subject. This issue is gaining more significance as advances in technology have extended the threshold in terms of the economical feasibility of tighter and deeper reservoirs. In the third chapter Aliverti *et al.* discuss methods used in an integrated borehole-scale characterization aimed at predicting fracture network and assessing fracture porosity in a tight reservoir.

The work demonstrates the incorporation of oriented core and wellbore images to calculate the geometrical parameters of each feature (dip direction, dip, size, terminations) and to classify them according to their filling (e.g. oil, water, shale, and calcite). In addition the total fracture population was studied to derive the number of fracture sets, their orientation, spatial distribution along the cored/logged interval, distribution laws of the fracture length and relevant minimum radii and fracture aperture estimate. Based on the results a stochastic simulation of fracture network at wellbore scale was built. Fracture porosity evaluation, matrix block size, and fracture network connectivity at wellbore scale constitute the outputs of such simulations. The application of the method is demonstrated through a study on a tight, platform carbonate reservoir, Southern Apennines, Italy.

Integrated borehole to reservoir scale characterization

This theme demonstrates the essential need to integrate multi-source, multi-scale data in fracture characterization. In this context it links borehole-scale observations, like those covered in the previous section, to reservoir-scale/interwell-scale observations (seismic data). This section includes two chapters.

The first paper by Hesthammer and Fossen illustrates an example from the North Sea Gullfaks Field, using integrated structural interpretation to optimize fracture characterization utilizing all available seismic surveys, well log correlation, dipmeter and core data. Interpretation of seismic data helps understand large-scale structural and stratigraphic geometries. Time-lapse seismic (4D-seismic) helps to identify changes in reservoir properties caused by operational activities like injection and production. Well log correlation is used to document variations in sequence thickness caused by sedimentological or structural changes whereas dipmeter data tie observations of bedding orientation from subseismic scale (borehole scale) to seismic scale. Core data represents the most detailed (millimeter to meter scale) data available and can yield information on rock properties as well as sedimentological and structural features. Small-scale deformation structures such as deformation bands and fractures can be identified and characterized effectively. In addition, it is possible from unoriented cores to find the orientation of bedding and deformation structures. This information is compared to observations from dipmeter data, well log correlation data and seismic data to improve the interpretation.

The second chapter in this section, by Yale, deals with fault and stress magnitude controls on variations in the orientation of in situ stress. Over the last decade in-situ stress characterization has been gaining impetus, due to the realization of the impact of current-day *in-situ* stresses on the performance, of both fractured and non-fractured reservoirs. Fracture orientation (for both natural and induced fractures, e.g. hydrofracturing stimulation of reservoirs), well stability, well placement and design, and permeability anisotropy in reservoirs are all strongly affected by variations in the current-day stress field.

Using stress orientation data from a number of fields in different tectonic environments, Yale tried to determine some of the tectonic and geologic controls on variations in *in-situ* stress orientation. The findings show that distance to large faults, fault structure, and magnitude of current-day tectonic stress play primary roles in determining whether the regional stress field will be perturbed in a given reservoir, and whether small-scale variations in the stress field can be expected.

Highly stressed terraines (with large horizontal differential stress) are characterized by a more consistent stress field than tectonically quiescent areas. Faults can play a significant role in rotating the local stress field. The smaller the difference between the maximum and minimum horizontal stress magnitude (i.e. lower tectonic stress), the larger a fault's zone of influence is. Large-scale faults, which compartmentalize the reservoir into discrete fault blocks, can lead to significant stress orientation variations across the reservoir, even in areas of large differential stress.

Reservoir-scale characterization using seismic data

In this theme two chapters illustrates the application of two 'unconventional' seismic data analyses and interpretation of reservoir-scale fracture characterization.

The first work by Trappe and Hellmich addresses the utilization of seismic volume attributes for fracture analysis. Seismic volume attributes are useful in the characterisation of subtle faults and fractures that cannot be recognized on seismic sections (their vertical offset is below seismic resolution), incorrectly referred to as 'subseismic' faults. The seismic attributes are based on neighbourhood analysis of the seismic signal and uses 2D or 3D data. To detect fractures, attributes such as coherency, that quantify change in the seismic signal, are used. Case studies are presented to show the impact of the attribute analysis on fracture characterization of reservoirs. Seismic multi-trace filtering to compute 2D and 3D seismic volume attributes are used for this purpose. This includes advanced seismic processing algorithms with extensive use of higher order statistics and feature extraction methods. These methods are as applicable in fields such as medical image processing or material science, where direct measurements of desired properties are either costly, or impossible.

In the second chapter of this section, Jupe *et al.* discuss case studies in which microseismic (passive seismic) monitoring contributed to the development and management of hydrocarbon and geothermal reservoirs in which fractures play an essential role. Microearthquakes (microseismic events) are induced during hydrocarbon and geothermal fluid production operations in naturally fractured reservoirs. The technology is based on the monitoring and analysis of microearthquakes. They typically result from shear-stress release on pre-existing faults and fractures due to production/injection induced perturbations to the effective stress conditions. These stress changes may be due to reservoir depletion, flooding or stimulation operations. Over a number of years it has been shown that microseismic monitoring has the potential to provide valuable time-lapse 3D information on the geomechanical processes taking place within a reservoir. These processes include the distribution of fluid flow and pressure fronts within naturally fractured systems, production-related compaction and the re-activation of faults. With the advent of permanent reservoir monitoring systems (e.g. intelligent wells), microseismic monitoring has the potential to become a practicable means of time-lapse (pseudo-real time) imaging of hydrocarbon reservoirs.

Outcrop-based characterization and modelling, on plate tectonic scale to predict in-situ stress regime

In this section, Claudio Lima discusses present-day compression across the South American plate. He presents observations, numerical modelling and some implications for petroleum geology. Stress and tectonic data (space-based geodetic results, seismicity, fission track analysis, and analysis of leakoff and hydraulic fracturing data) and intraplate stress field numerical models indicate that the maximum principal stress is horizontal for most Brazilian basins. The compression/shortening is most probably due to the convergence of the South American and the Nazca plates and the divergence of the South American and the African plates.

A conceptual model for the plate-wide deformation is presented and numerically tested using elasto-plastic rheologies. The model states that in response to the compression, the lithosphere as a whole (or only the crust if thermal gradients are high enough) tends to fold and fracture. This tendency is stronger during peaks of the Andean orogeneses. The forming antiforms are responsible for uplift along the erosional basin borders, whereas the forming synforms are sites of continental sedimentation, at basin centers. The denudation of sedimentary covers promotes the exhumation of deeper and deeper rocks, outcropping at the foot of retreating scarps. Consequently, the erosional borders of the basins form local topography highs with respect to the adjacent basement.

In exploration, neotectonics, including in-situ stresses, are usually disregarded, especially in 'passive' margin basins. However, neotectonics impact the distribution and preservation of petroleum accumulations, since (i) accumulations are ephemeral in a geologic time scale, being strongly dependent on seals fine geometry and biodegradation (ii) a strong positive correlation exists between permeability anisotropy and SHmax (iii) the source rocks of the most important Subandean and intraplate petroleum systems are still in the oil generation window and (iv) the disruption of 'kitchens' of generation is a positive factor to primary migration. This inference seems to be confirmed, since the most important South American petroleum accumulations are found along the actively deforming border between South American and Caribbean plates. Indeed, the most important accumulations in marginal basins are found in the Southeastern Brazilian margin (the Campos basin), which has been deformed the most with respect to other margins during the Cenozoic, and continues to be the most seismically active. Fracture networks on the Belluno Syncline, a fault-propagation fold in the footwall of the Belluno Thrust, Venetian Alps, northeast Italy.

Outcrop-based fracture characterization

Outcrop studies remain the most important source of our conceptual structural models of subsurface structural traps and associated fracture patterns. The distribution of fractures in space and their evolution relative to the host structures are vital for exploration and development (e.g. borehole design). In this theme, Zampieri and Grandesso studied the Belluno Syncline, in the Venetian fold and thrust belt in Italian Southern Alps. This SSE-vergent chain mainly developed during the Neogene as a back-thrust belt of the Alps deforming the northern margin of the Adria plate. The syncline is asymmetric, with a steep backlimb, as the forelimb of the paired Monte Coppolo Anticline, resulted from fault-propagation folding during the development of the underlying Belluno thrust. In plan view the Belluno thrust shows a prominent curvature interpreted as reactivation of inherited Mesozoic extensional structures. The hinge of the Belluno syncline presents a similar curvature. Rocks outcropping in the syncline core are Upper Chattian to Langhian fine-grained molassic sediments, mainly siltstones and marls.

Most fractures on the Belluno Syncline have formed at high angles to bedding. The dominant fracture trends are sub-parallel and orthogonal to the fold hinge. Sometimes these fractures show plumose structures characteristic of extension (mode I) fractures and are referred to as longitudinal (bc) joints and cross (ac) joints respectively. Other fracture trends oblique to the hinge line are found on limbs distant from the fold hinge. They are referred to as oblique (shear) fractures. Throughout the western part of the Belluno Syncline the fracture network maintains a roughly symmetrical distribution with respect to the fold hinge, suggesting a development in association with folding.

Geomechanical and geodynamic modelling on reservoir scale

This is discussed through four key chapters. The first presents a method for stress modelling from local data. The study by Muller *et al.* presents a new method for smoothing orientation data in general and demonstrates its application to in-situ stress modelling.

Smoothing algorithms provide a means of identifying significant patterns in sets of oriented data, eliminating local perturbations within the observations and predicting patterns of oriented data in places which lack observations. Muller *et al.* smooth orientation data with a distance-related method of data weighting as an alternative to previous weighting algorithms. This method is developed on the basis of a statistical smoothing algorithm. They can be applied to orientation data of 180° periodicity such as maximum horizontal tectonic stresses (S_H) as compiled in the World Stress Map database. This method enables the user to discriminate between local (<250 km of lateral extent) and regional stress fields (approximately 250–5000 km of lateral extent), and to compare S_H with other directional data such as fault trends or strain data. The technique is demonstrated by producing stress models for NE America, the Himalayas and Western Europe. The accuracy and smoothness sensitivity is tested by varying the scale and smoothing. They also give recommendations for appropriate choice of these parameters.

The second chapter in this section, by Wynn and Stewart, deals with the role of spectral curvature mapping in characterizing subsurface strain distributions. The curvature of key geological surfaces can be used to assess the strain they have undergone. In many hydrocarbon reservoirs, this strain is expressed as brittle fracturing that may significantly impact reservoir performance. Wynn and Stewart describe the development of an algorithm for measuring the curvature of gridded surfaces derived from seismic data. For any grid node, the algorithm calculates the magnitude and orientations of the two principal curvatures, K_1 and K_2, from which other curvature measurements can be derived, such as Gaussian curvature and summed absolute curvature (K_1+K_2). The algorithm has also been used to generate plots of summed absolute curvature as a function of grid node separation (k versus λ). These 'spectral' or kλ plots can be generated for each grid node and allow the definition of short wavelength, high amplitude noise cut-off lengths. They also deliver intermediate wavelength features such as fault drag or buckle folding and the identification of long wavelength (basin scale) curvatures. Portions of this data can be collapsed into single values by calculating the integral of the kλ curve. Further filters designed to screen the effects of background tectonic, or non-tectonic curvatures can be applied to the kλ integral.

This algorithm has been verified using data from several North Sea chalk fields. A range of alternative types of curvature and curvature spectra are compared with other approaches to curvature calculation and other factors relevant to the calibration of such techniques in terms of the distribution of brittle fractures in sedimentary rocks.

The kλ integral provides a relatively simple approach to calculating the degree of multi-wavelength strain present at a particular grid node. Freeing algorithms from the restriction of the 'arbitrarily' selected minimum grid node spacing is a key step towards calibrating measured curvature against strain mechanisms. However, care must be taken to separate intrinsic and tectonic curvatures when generating and interpreting kλ plots and their integrals.

The third chapter within this topic, by Smart *et al.*, deals with reservoir characterization for the management of stress-sensitivity. In spite of the well-established effort to effectively characterize and model borehole-scale sensitivity, reservoir-scale studies are lagging behind and have only recently gained some impetus. In this chapter the authors argue that fractured reservoirs must be considered stress-sensitive, with this possibly being masked in the past by high productivities and abundant reserves. A basic conceptual model for all reservoirs is proposed, consisting of intact blocks of rocks bounded by discontinuities (fractures and bedding-parallel), loaded by an anisotropic stress state. It is argued that such a model should be used to drive the reservoir characterization, with the premise that the new generation of coupled simulators can usefully accommodate this data set.

Tuncay *et al.* discuss a method to simulate 3D fracture network dynamics in reservoirs, faults and salt tectonic systems. The method is based on the numerical solution of rock deformation processes coupled to the myriad of other basin reaction, transport and mechanical (RTM) processes. Seismic, well log and surface geological data are used to quantitatively assess distribution of fractures, stress, petroleum and porosity, grain size and other textural information.

The model uses an incremental stress rheology that accounts for poroelasticity, nonlinear viscosity with yield/faulting, pressure solution and fracturing. It couples mechanics to multiphase flow and diagenesis (through their influence on effective stress and rock rheological properties, respectively). The resulting model is 3D in terms of the full range of fracture orientations and the tensorial nature of stress, deformation and permeability. All rock properties (rheologic, multi-phase fluid transport, grain shape, etc.) are coevolved with the other variables. Examples are used to illustrate the relative importance of various overpressuring mechanisms, lithology and flexure on the location and characteristics of a fracture network.

Prediction and modelling of fluid flow in fractured reservoirs

The main objective of fracture characterization is to constrain their impact on reservoir properties such as permeability. Jolly and Cosgrove use geological evidence of fluid flow in an attempt to understand fluid flow patterns in fracture networks. Because many fluids (e.g. gas, water etc.) leave little or no evidence of their passage through the rock others such as magmas and fluidized sediments preserve the pathways they follow by forming dykes and sills. In their study Jolly and Cosgrove found that the pathways preserved by the two types of fluids are different (i.e. the spacing of the clastic dykes follows a power-law distribution and that of the igneous dykes a lognormal distribution). It is suggested that this in part might reflect the different properties of the dyke material (specifically its permeability) which determines whether or not the fracture containing the dyke can continue to act as a channel of easy fluid migration once the dyke has been emplaced.

In the second chapter in this theme Ewing and Spagnuolo discuss the difficulties and uncertainties in mathematical/numerical modelling of fluid flow in fractured media. The chapter especially discusses uncertainties arising in reservoirs, which have large, dominant pathways for high velocity flow. In such environments, conventional single and dual-porosity/dual-permeability models for simulation cannot adequately represent the flow processes. Instead, a major paradigm shift in both mathematical modelling and numerical methods to discretize these models are required. The author argues that new simulators must include non-Darcy flow models that allow channels and non-traditional multiphase flow models. In order to accurately describe complex localized phenomena that may dominate the flow process, the simulators must be able to accurately describe complex localized geological structures in the same content as enormous, field-scale reservoirs. This requires the ability to have complex, non-orthogonal flexible localized grid capabilities tied to larger, more-uniform grids via domain decomposition and various mortar finite element, finite volume element formulations. Furthermore, localized time-stepping procedures coupled with adaptive gridding may be needed to deal with such reservoirs. Ewing and Spagnuolo presents aspects of mathematical modelling and numerical methods that address each of these difficult areas of simulation. These techniques will be essential in trying to simulate the complex systems of large vertical faults and fracture systems that dominate the flow in many of the heavily fractured reservoirs worldwide.

Simulation of water-gas flow in fractured porous media by AL-Khlaifat and Arastoopour is the subject of the third chapter in this group. The chapter tackles porous gas reservoirs characterized by a low-permeability matrix, and a high-permeability fracture system. The transient, three-dimensional, two-phase numerical model is presented for simulating the simultaneous flow of gas and water through porous and fractured media. It assumes a single horizontal fracture perpendicular to the flow direction and considers both fluids as incompressible and immiscible. The study takes into consideration the effect of capillary pressure and relative permeability. Technically, the finite volume approach is used to discretize the equations. The set of discretized and linearized equations are solved using the IPSA (Inter-Phase Slip Algorithm) method. The results of this study indicate that the multi-layer reservoir provides better estimates of post-fracture performance compared to a more conventional, single-layer reservoir description.