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DOI
10.1144/petgeo2019-122

Publication date
2019

Document Version
Accepted author manuscript

Published in
Petroleum Geoscience

Citation (APA)
Finkbeiner, T., Bertotti, G., & Geiger, S. (2019). Introduction to the thematic collection: Naturally fractured reservoirs. *Petroleum Geoscience*, *25*(4), 351-353. https://doi.org/10.1144/petgeo2019-122

Naturally fractured reservoirs

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Naturally fractured reservoirs not only contain a significant share of the world's hydrocarbon resources, they are also important to support the transition to a low carbon energy future, for example when producing low- and high-enthalpy geothermal heat or sequestering CO_2. At the same time, these reservoirs present some of the most daunting challenges the energy industry is faced with. With a few exceptions, the rock matrix is generally responsible for the storage capacity of a reservoir whilst existing layer-bound and cross-layer fracture sets/corridors across a wide range of length scales define the characteristics of hydraulic connectivity (Ramsay and Huber 1987). In other words, flow in the reservoir (hydrocarbons, brine, or CO_2), the ability to recover crude oil and gas (or geothermal heat), CO_2 migration pathways, production profiles from wells, and the risk of bypassing oil and heat are greatly affected by the fracture network (Zimmerman and Bodvarsson, 1996; Gale et al, 2014).

In general, we identify two main challenges associated with the accurate modelling and forecasting of fluid flow in naturally fractured reservoirs. The first one is to reliably predict the permeability structure of the fractured rock. Such permeability is affected by the host rock's geological history and not only a function of the matrix (or primary) permeability but also the natural fracture and fault system (Egya et al., 2018). The latter requires proper characterization of the natural fracture network and an understanding of mineral dissolution and precipitation processes within the host rock and natural fracture network (e.g., dissolution in hydrothermal systems, dolomitization) (Tsang and Neretnieks, 1998; Davies and Smith, 2006; Laubach et al., 2019). Understanding these processes is equally important in petroleum reservoirs, geothermal aquifers, and CO_2-sequestration systems since they control the distribution and movement of hydrocarbons, flow of hot water, and CO_2 migration (Reijmer et al., 2018). In contrast to siliciclastic reservoirs, these processes are even more prominent in carbonate reservoirs, which are characterized by extensive interactions between host rock and potentially reactive fluids resulting in extensive dissolution and the formation of multiscale cavities and super-conductivity zones (Berkowitz, 2002; Scanlon et al., 2003).

The second challenge refers to our ability to predict production (or injection) performance and related uncertainties of a field (or reservoir) once it is operational and brought on stream. Robust flow simulations predicting phenomena such as water break through or coning, the advancement of steam floods, flow of polymers, leakage pathways of CO_2, or temperature profiles require a profound knowledge of the permeability distribution. Furthermore, the *present* in situ conditions and future changes of the reservoir (for instance changes in stress conditions or mineral scaling and related alterations in fracture hydraulic aperture) (e.g., Rutquist and Stephansson, 2003; Finkbeiner et al., 1998).

Because of our limited ability to characterize and quantify these complexities, naturally fractured reservoirs pose significant challenges when modelling fluid flow as well as making reliable forecasts about future reservoir performance (Laubach et al., 2019).

Figure 1 shows such complex fracture patterns in a world-class outcrop analogue in Oman from Cretaceous reservoir reservoirs rocks that are under production in nearby fields. What makes this particular outcrop analogue especially interesting and relevant is that critical elements to characterizing reservoir architecture such as the here exposed clinoforms and natural fracture sets are mostly sub-seismic in scale (i.e., not detectable with seismic surveys). Yet, these are important features for successfully modeling waterflood performance in a reservoir simulator (Adams et al. 2011; De Keizer et al., 2007).

This thematic set addresses some of the complexities associated with naturally fractured reservoirs in detail. We selected ten papers that cover a wide variety of themes such as structural geology, fracture genesis, network characterization and modeling, rock mechanics, as well as reservoir engineering. Most of these papers were originally presented at the European Association's of Geoscientist and Engineers 3rd Workshop on Naturally Fractured Reservoirs, held in February 2018 in Oman which focused on calibrating models for naturally fractured reservoirs using static and dynamic data.

A number of the selected manuscripts focus on outcrop analogues. When properly analyzed and integrated with novel approaches these studies often reveal key information to understand the architecture and geo-plumbing of fractured reservoirs in the subsurface. This is of particular importance to address the challenging task of calibration, which – when done properly – significantly reduces uncertainties in static and dynamic naturally fractured reservoir models. Furthermore, calibration can be implemented successfully at any stage during field life. Other contributions provide new insights into the processes associated with fracturing and migration of hydrocarbons, which also find application in unconventional, organic rich source rocks.

Weisenberger et al. describe a process by which calcite contained in sandstone host rock is mobilized and re-precipitates as carbonate cement within a certain temperature range in natural fractures wider than 1mm. This process can be predicted based on how certain minerals are distributed within the host rock and, hence, provides an opportunity to forecast whether fracture are hydraulically sealed or open.

Petrographic and organic-geochemical analyses on bitumen samples extracted from fractures and their host rock deliver insights into fracture genesis and associated bitumen flow in a Jordanian unconventional hydrocarbon play. Through analyses, Abu-Mahfouz et al. determine the controls of bitumen mobilization fracturing mechanisms by regional loading stresses.

Artificial intelligence tools provide a different methodology to predict rock properties such as Young's modulus and compressive rock strength in carbonate rocks. These are important parameters for characterizing the mechanical layering and fracturing in such reservoirs. Belayneh et al. discuss this approach using a prominent Middle Eastern reservoir example.

Naturally fractured crystalline basement rocks are a fascinating but also particularly challenging reservoir type since their fracture network acts as both storage medium and flow channels for oil. Bonter and Trice highlight a specific and integrated data-intensive approach required for these reservoirs in order to understand the connectivity and hydraulic behavior of the existing fracture network.

The study by Wang et al. also focuses on crystalline basement and quantifies spatial arrangements of fracture and joint mapped in the Teton Range (Wyoming, USA). With the help of intensity plots as well as correlation counts self-organized fracture clusters can be discerned over a wide range of length scales. This approach provides the means to greatly improve fracture permeability models and make flow simulations more robust.

Similarly, Long et al. demonstrate with an outcrop analogue study from Kurdistan how fractured carbonate reservoirs can be properly characterized across a wide range of scales. Critical in this approach is to develop robust fracture length-intensity graphs combined with power law distribution functions in order to understand and predict fracturing as a function of regional deformation, proximity to high strain zones such as faults, and thickness in mechanical layering.

Carbonate formations often contain random background fractures and fault damage zones. Aubert et al. studied the outcrop of a Lower Cretaceous carbonate to map and identify the two fracture types. The study was augmented by thin section SEM analyses and revealed that the initial host-rock background fracture network greatly impacts fault zone deformation and hydraulic properties.

Boersma et al. utilize a carbonate cave system in Brazil and combine outcrop observations, drone imagery with numerical modelling to characterize channelized fluid flow through karstified fracture conduits. The study highlights that geometrical features such as length, orientation and connectivity play an important role in the preferred flow orientations.

The paper by Welch et al. utilizes a geomechanically-based deterministic approach to model the growth of a layer-bound fracture network. In doing so, they examine a variety of processes ranging from fracture nucleation, rates of fracture propagation as well as fracture termination (resulting from intersection or stress effects) that control growth of fracture sets as well as entire fracture network geometries in nature.

From an engineering aspect, Spooner et al. propose novel flow diagnostics as a complement to full-physics reservoir simulation. The diagnostics approximate dynamic reservoir responses in very short time intervals. Hence, this approach is ideal to compare a variety of reservoir models before running full simulations.

Overall, the papers presented in this special volume present some innovative contributions to characterizing and modelling naturally fractured reservoirs but also highlight the need for future cutting-edge research to advance this challenging field.

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Figure 1. Naturally fractured carbonates at Jebel Madmar in Oman.