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Coupled Stress-fluid Pressure Modelling of Stimulated Rock Volume in Shale - Impact of Natural Fractures and Beef

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SUMMARY

Unconventional shale reservoirs have practically no in-situ permeability, but they may be rich in natural fractures, which can positively or negatively impact hydraulic fracturing. We study a naturally fractured shale formation, with bed-perpendicular fractures, which are mostly cemented, fracture corridors and bedding-parallel calcite veins (beef). Microseismic indicates that the Stimulated Rock Volume (SRV) is heterogeneous and anisotropic, which is likely related to reactivation of the natural structural heterogeneities.

At in-situ conditions, the shale is overpressured, but the pore pressure is below the required threshold to reactivate natural fractures. During hydraulic fracturing, fractures may be locally reactivated. The local reactivation is quantified using a coupled stress-fluid pressure Finite Element model, based on a discrete fracture network constructed around a pilot area with several horizontal and vertical wells.

The models show that only a small part of the fracture network close to induced fractures is reactivated, creating an anisotropic SRV. Vertically, beef limits growth of induced fractures, while increasing the aperture and length. Furthermore, beef can generate horizontal high-permeability zones, increasing the SRV. These models, when accurately calibrated using pressure interference data, are useful to optimize well placement and completion strategies.

Introduction

We analyse the role of natural fractures in a shale formation with high TOC and porosity, but nanodarcy permeability. Image logs and cores indicate a high density of bed-perpendicular fractures, but under in-situ stress conditions, these fractures are hydraulically closed. Vertical cores also indicate bedding-parallel ash beds and calcite layers, often referred to as beef (Rodrigues *et al*., 2009). The spacing between beef layers varies with depth, but on average it is 2-3 m. The beef has likely formed during burial in overpressure conditions resulting from generation of hydrocarbons (Rodrigues *et al*., 2009).

The bed-perpendicular fractures and bedding-parallel features introduce vertical and horizontal heterogeneities that may positively and negatively impact the efficiency of hydraulic fracturing and the corresponding stimulated rock volume. Reactivation of natural fractures can provide additional flow paths, but if these fractures are cemented, they may form planes against which hydraulically induced fractures terminate. The bedding-parallel features form distinct mechanical units that limit vertical growth of induced fractures. However, these features may also act as slipping planes along which induced fractures can propagate horizontally (Gu *et al*., 2008; Rutledge *et al*., 2014; Stanek and Eisner, 2013). Furthermore, slip along bedding may increase fracture aperture (Gu *et al*., 2008).

Using a coupled stress-pore pressure model, calibrated to in-situ stress conditions, we quantify the positive and negative impacts of these heterogeneities on the stimulated rock volume to optimize the hydraulic fracturing strategy.

In-situ stress and natural fracture characterization

The studied shale formation is overpressured with a fluid pressure approximately 7MPa below Shmin. Due to continued regional compression from the west (N110), Shmax is the maximum principle stress (σ_1), with vertical stress as σ_2.

An integrated study of image logs, cores and seismic attributes indicates three bed-perpendicular fracture orientation sets. Set 1 is a joint set striking parallel to the regional Shmax (N110). The other sets strike at N070 and N140, and are interpreted as part of a conjugate system with a N110 bisector. Seismic attributes and image logs indicate the presence of fracture corridors striking N110 and N070, but outside these corridors spacing is homogeneous. A Discrete Fracture Network of the natural fractures is built using well data and seismic (Figure 1).

Methodology

Hydraulic fracturing relies on increased fluid pressure to generate and propagate induced fractures and reactivate natural fractures. We model the impact of hydraulic fracturing on the in-situ fluid pressure field using the numerical simulation code ABAQUS (Dassault Systemes). The models consider the impact of far-field tectonic, Poisson's and overburden stresses.

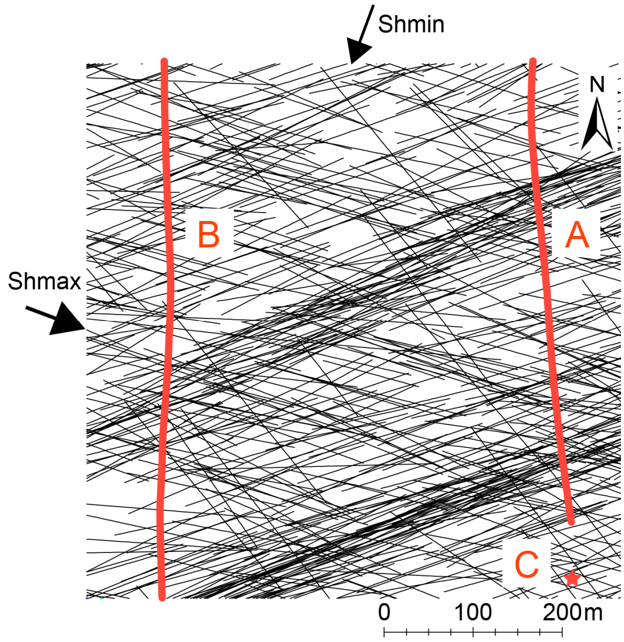

Figure 1 *2D horizontal slice of the DFN and 3 wells.*

Horizontal 2D and 3D models are used to quantify the impact of increased fluid pressure on natural fractures while the role of bedding-parallel features is quantified using vertical 2-D models that consider the mechanical stratigraphy. Change in fluid pressure is represented by increasing pressure at the injection points along wells, using transient flow models assuming fully saturated single-phase flow of water. Rock failure and subsequent changes in porosity and permeability are modelled using a damaged plasticity representation (Smart *et al.*, 2014).

Horizontal flow anisotropy

Horizontal flow is modelled between 2 parallel horizontal wells, 400m apart (Figure 2a). In well A, 5 stages of 4 hydraulic fractures each are modelled, with an average injection pressure of 55 MPa for a duration of 6 hours. In well B, 10 stages of 3 hydraulic fractures are modelled, with identical injection times and pressures. After each stage, the well is shut in until the in-situ pressure has reached a new steady-state equilibrium before starting with the next stage.

During hydraulic fracturing of well B, pressure interference was observed in well C but not in well A. The interference test data is used to calibrate the model, which indicates that flow after hydraulic fracturing is heterogeneous. Rather than reactivating the natural fracture network, it is more likely that induced fractures connect to a subset of natural fractures to generate localised flow paths, approximately parallel to the Shmax. This results in flow anisotropy, with the highest permeability sub-parallel to Shmax (Figure 2).

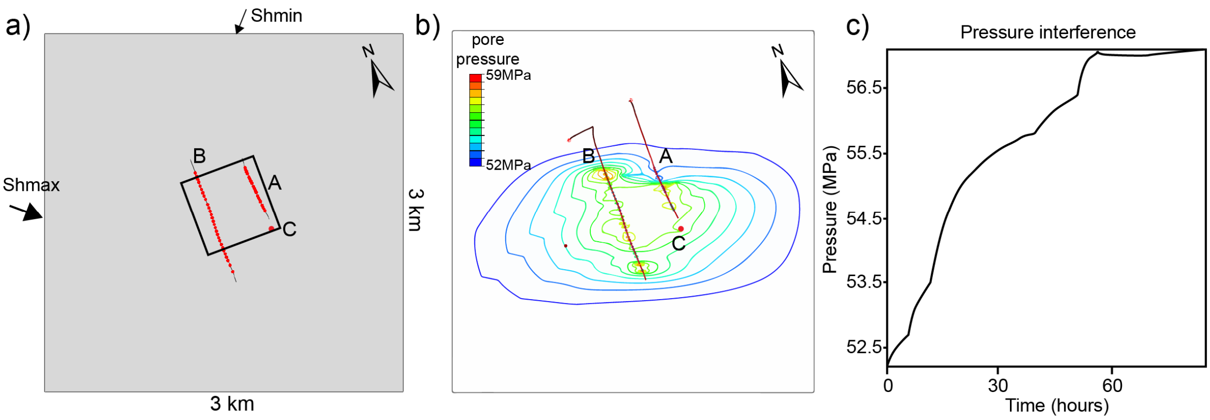

Figure 2 *a) Horizontal model setup; b) Contours of increased pore pressure after fracturing; c) change in in-situ pore pressure as a function of time.*

Mechanical stratigraphy and fracture propagation

Core data indicate that while the shale is relatively homogeneous, ash beds, beef and calcite nodules are abundant, creating a vertical heterogeneity. Mechanical properties and porosity have been measured in-situ. Using these properties, we generate a high-resolution vertical 2D model of a 20m interval in the vertical well. This resulting model consists of 51 mechanical units, including several nodules, beef features and ash beds.

The interface between calcite features (beef, nodules) is represented using low friction coefficients, based on the high mechanical contrasts (Gu *et al.*, 2008). The interfaces between different shale units and ash beds have high friction coefficients, based on core observations (no induced fractures along ash beds during core extraction) and mechanical properties.

Although the ash beds have a significantly higher toughness compared to the shales, the induced fractures can propagate through them if the beds are relatively thin (less than 10cm). Although there is a contrast in toughness, the shear stiffness is high between the interface of the ash beds and shale, resulting in a single mechanical unit (Figure 3a).

The calcite features do form a separate mechanical unit, resulting from the contrast between calcite and shale, generating a low shear stiffness. When an induced fracture encounters a calcite layer, the fluid pressure generates slip along the bedding plane, limiting the vertical growth of the induced fracture (Figure 3b). However, the low shear stiffness can result in a larger fracture aperture and subsequent horizontal length. While the induced fracture is limited vertically, its horizontal extent is increased, and the increased aperture combined with the reactivated bedding plane provide fluid pathways that increase the horizontal impact of the induced fracture.

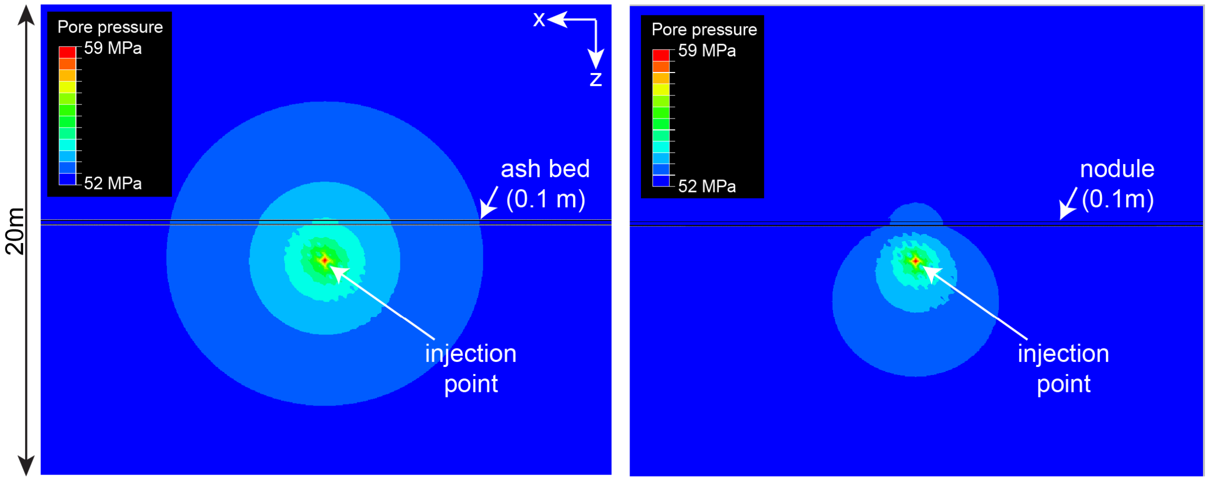

Figure 3 *Vertical cross-section of 2 shale units separated by an ash bed (left) and a nodule (right), showing the change in pore pressure during injection. All layers have representative mechanical properties derived from logs. The interface between shale and the ash bed has a high friction coefficient. The interface between nodule and shale has a low friction coefficient.*

Conclusions

While shales are generally considered as homogeneous reservoirs, the studied formation is horizontally and vertically heterogeneous, resulting in flow anisotropy during hydraulic fracturing and production. Horizontal anisotropy results from the high stress anisotropy combined with a pre-existing fracture network that strikes predominantly NE to SE, with the principle flow direction between N100 and N120 (i.e. sub-parallel to Shmax).

Vertically, fracture propagation and flow are controlled by the mechanical units. Vertical growth of induced fractures may be arrested by ash beds, although thin ash beds can still be expected to fail during hydraulic fracturing, because of the large shear stiffness. The bedding-parallel calcite features have a low shear stiffness, providing bedding-parallel slip planes that arrest vertical growth of induced fractures. However, this same mechanism can increase the aperture and horizontal length of induced fractures, increasing the horizontal extent of the stimulated rock volume. Furthermore, horizontal flow along reactivated calcite may connect induced fractures to fracture corridors that would otherwise not be within reach of hydraulic fractures.

These heterogeneities complicate the design of hydraulic fracturing strategies, but quantification of their impact on stimulated rock volume through calibrated numerical models can be used to optimize the hydraulic fracturing strategy.

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