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Microseismic Geomechanical Modelling of Asymmetric Upper Montney Hydraulic Fractures

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Summary

Geomechanical modelling is a powerful tool to quantitatively interpret a hydraulic fracture network model by validating it with the observed micoseismic deformation. Microseismic data recorded during an Upper Montney stimulation of a horizontal well with a sliding sleeve completion was used to calibrate a microseismic geomechanical model. The 3D hydraulic-mechanical model was populated using available geologic data, a microseismic constrained discrete fracture network (DFN), and a vertical 1D stress profile simulating the injection sequence. Synthetic microseismicity from the model was matched to the field observations to validate asymetric fracture growth associated with stress shadowing between stages. The calibrated model was then used to examine other engineering designs including the treatment and well completion. For a plug and perf completion scenario, stress shadowing between perforation clusters was shown to result in fracture assymetry. However, the assymetry and more importantly the corresponding reservoir contact with the propped portion of the fracture can be managed through the fracture design and cluster spacing. The case study illustrates a microseismic geomechanics workflow that uses field observations from an open hole, sliding sleeve completions strategy to calibrate the propagation of a hydraulic fracture during a single stage of injection. Results support the observed asymmetry and suggest stress shadow as a possible explanation for the asymmetric fracture propagation. The calibrated geomechanical model provides a workflow to leverage microseismic data for optimizing the hydraulic fracture and well design.

Introduction

Microseismic monitoring is a standard technique for inferring the overall extent and geometry of the fracture network during hydraulic fracturing of unconventional reservoirs. The detected microseismicty represents only a small portion of the overall deformation during the treatment of the reservoir. Portions of the fracture system and associated proppant distribution will be aseismic but typically represent some proportion of the entire microseismic volume. The injected volumes, fluid rates and hydraulic properties, general state of stress, rock properties and pre-existing fracture characteristics control the fluid flow, deformations and distribution of the microseismic cloud. Microseismic geomechanics builds a coupled hydraulic and mechanical 3D model to link the geological data and completion strategy with the overall deformation of the reservoir during the fracture treatment (Maxwell et al., 2015). The model provides an explanation for the complex geomechanical evolution of the reservoir. The model also provides the effective proppant distribution during the fracture stimulation that can be quantitatively matched to the observed microseismic deformation and net injection pressure. The calibrated fracture model, along with the validated state of stress and rock properties, can then be used for improved fracture design, microseismic prediciton and sensitivity studies simulated for completion optimizations. (Chorney and Maxwell, 2015).

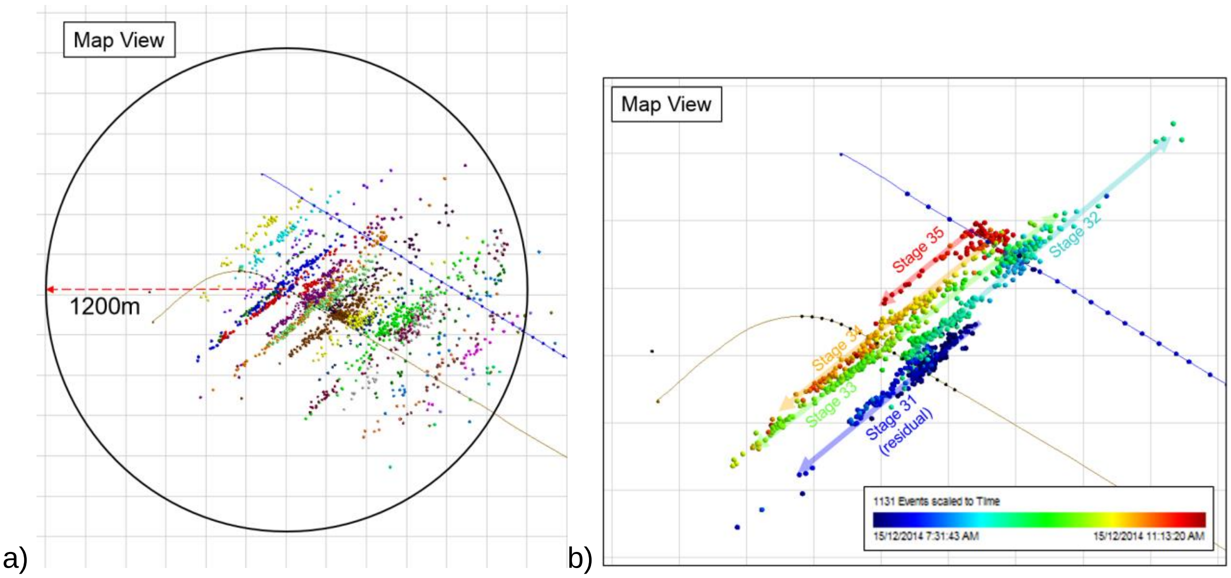

Figure 1. a) Plan view of the microseismic data b) Plan view of the microseismic data illustrating varying degrees of asymmetry over stages 31-35.

The study examines an open-hole, sliding-sleeve hydraulic stimulation of the Upper Montney in North-East British Columbia, where a geophone string located in the heel portion of a horizontal well recorded microseismicity from 38 stage completion of an adjacent parallel horizontal well approximately 420m away. The spatial distribution of the microseismicity indicates a strong tendency of planar fractures with asymmetry towards the SW (see Figure 1a). The data shows varying amounts of asymmetric microseismicity for each stage (see Figure 1b). A geomechanical model is constructed to investigate the observed microseismic asymmetry and to provide the extent of the effective proppant distribution. Monitoring biases can potentially be the source of observed asymmetry which can be tested by examining the entire fracture geometry resulting from the total injected volume using a microseismic geomechanical simulation.

Stimulation of unconventional reservoirs in the Upper Montney has previously been shown to exhibit asymmetric distribution of the microseismic cloud along the wellbore (Maxwell et al., 2011), potentially impacting reservoir contact. Asymmetric propagation of the hydraulic fracture may be the result of various geological conditions including structural setting, tectonic stress, pore pressure heterogeneity and stress shadow effects from neighbouring stages. In this case study, the stage-by-stage variations suggest stress shadowing.

The Microseismic Geomechnical Model

The 3D geomechanical model described here is a fracture based modeling scheme that is able to quantitatively interpret the hydro-mechnical aspects of fracture propagation and its associated microseismicty. The modeling software package 3DEC has the unique capability of modeling the propogation of the tensile hydraulic fractures along with its interation with a pre-exisiting DFN, fully simulating the coupled hydraulic and geomechanical aspects of fracturing (Damjanac and Cundall, 2014). The formulation is a hybrid-continuum discrete element based code, coupled with fluid flow within the DFN. An explicit, time-marching and finite-difference scheme is applied to compute the stress and strain of the discrete elements. A discrete element contact law describes the forces and stability of the fractures. Fluid flow within the fracture network is driven by pressure gradients asumming Darcy's Law laminar flow. The model has the advantage that it is able to bridge the geological data, mechanical deformation and pre-existing fractures with the dynamics of the fracture propagation. Instantaneous slip in the model is tracked to generate synthetic microseismicity (including time, magnitude, mechanism and location).

Model Inputs

A well constrained geomechanical model requires geologic inputs including elasticity parameters, stress field, density and fracture characteristics of the DFN. Stress, pore pressure, and mechanical properties are estimated from the drilling logs. The minimum principal stress is calculated from the Poisson's Ratio, including corrections for pore pressure, tectonic stress and closure pressure from DFIT (Diagnostic Fracture Injection Test) analysis. Flow and build-up tests indicate an over-pressurization in the Montney. The vertical stress is estimated from the density logs and the maximum horizontal stress is estimated by shifting slighting above the vertical stress to maintain a strike-slip regime (Contreras et al. 2012, Reimer 2015 and Davey 2007).

Following QC of the microseismic data, which included considerations for magnitude senstivity and detection biases, the data shows asymmetric fracture propagation for a number of stages. In addition to the spatial distribution of the microseismicity, amplitude ratios (Sv/Sh, P/Sv, and P/Sh) from double-couple source mechanisms were used to infer orientations of the DFN. The microseismic data indicates a primary and secondary fracture set with an azimuth of 40 degrees E of N, dip 35 degrees and an azimuth of 87 degrees E of N, dip 35 degrees, respectively. Following Kohli and Zoback (2013), the TOC and clay content is used to estimate joints strength of the DFN.

Hydraulic Fracture Model

A geomechanical model is populated using the geologic data, DFN orientations, and stress inputs described above. For each stage, slick water was injected for 33 minutes at rate of $11m^3$/min including a 30/50 proppant ramp. The initial model shows a good microseismic match to stage 32 (see Figure 2a). Applying a horizontal stress gradient results in a close match to the asymmetric stage 34 (see Figure 2b). The simulations show a strong temporal and spatial match in terms of length, width, and height to the field microseismic data suggesting the model has the correct mass balance of fluid and proppant distribution for a single planar hydraulic fracture. In both cases, the fracture lengths and heights are on the order of 1km and 120m respectively. Since the same model can match the fracture geometry of both stages, we conclude that the asymmetry is real and likely a result of a stress shadow interaction between stages.

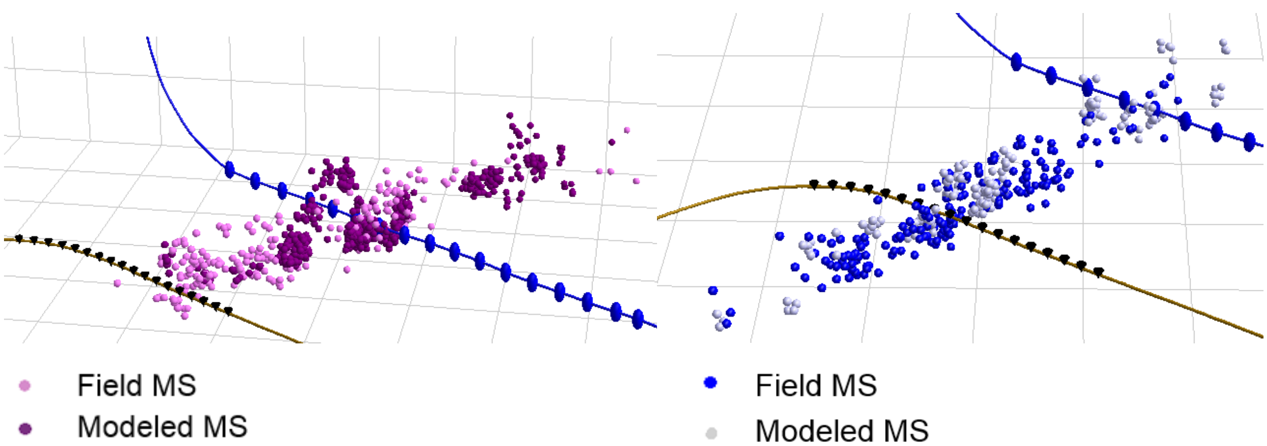

Figure 2 Comparison of synthetic and field microseismic data for Stage 32 (left) and Stage 34 (right).

Using the calibrated model, a multi-perforation cluster sensitivity study was conducted to explore the effect of the interaction of neighbouring hydraulic fractures due to the stress shadow effect. The simulation was conducted with the same injection sequence across 5 perforation clusters at the same rate of $11m^3$/min. Figure 3 shows a plan view of the synthetic microseismicity. The model shows a similar zig-zag effect highlighted in Figure 1b suggesting the stress shadow effect as a possible explanation for asymmetric fracture propagation. The neighbouring fracture causes a local increase in the Sh_{min} providing a stress gradient which drives the asymmetric fracture propagation.

The hydraulic fracture and proppant extents are shown for Stages 32 and 34 in Figure 4. The fracture propagation shows a well contained fracture with maximum contact in the upper Montney. The effective proppant concentration at a threshold of 1.0kg/m^2 is shown in Figure 5. The symmetric stage results in similar propped extents, but the concentration is higher near the well and hence improved.

Conclusions

This case study explored a hydraulic fracture stimulation of the Upper Montney. The microseismic data showed clear asymmetric propagation of the hydraulic fracture about the injection point for a number of stages, although a few stages show more symmetric fractures. Geologic data and a microseismic DFN was used to populate 3D geomechanical models. The simulations showed a strong temporal and spatial match of the microseisimic data to field observations.The model shows primarily depth contained, planar fractures

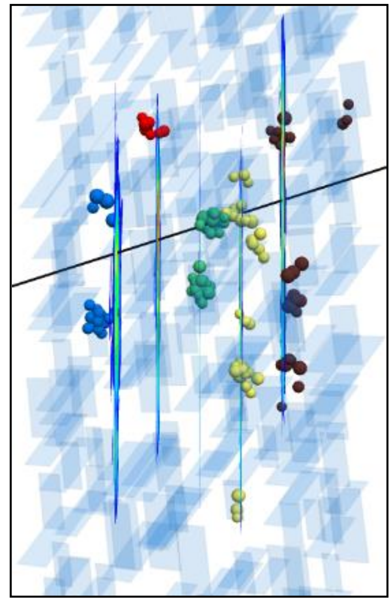

Figure 3. Asymmetric fractures from multiple perf clusters.

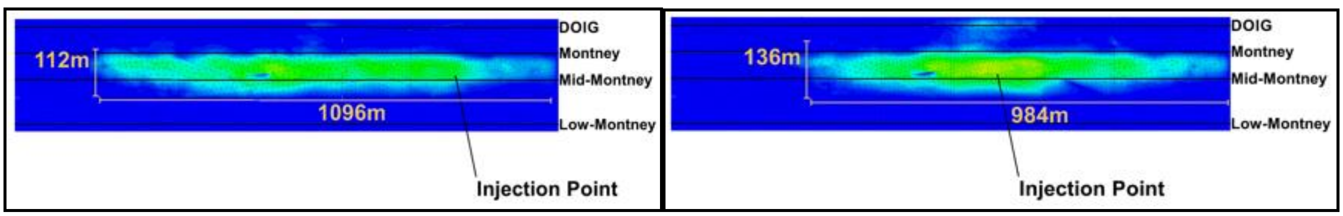

Figure 4. Hydraulic fracture extent. a) Asymmetric frature growth corresponding to Stage 34. b) Symmetric fracture growth corresponding to Stage 32.

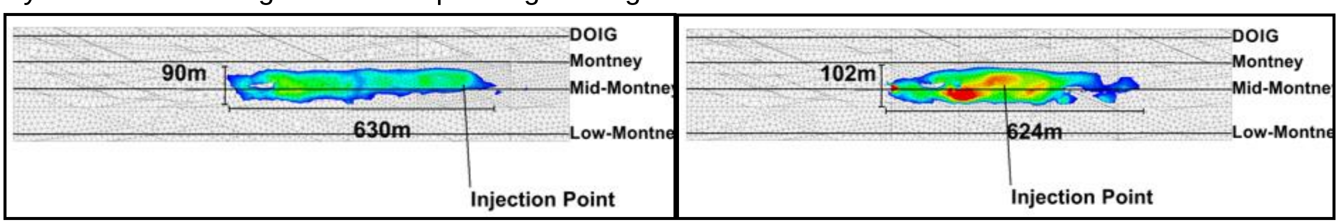

Figure 5 Effective proppant placement (1.0kg/m^2). a) Asymmetric fracture growth. b) Symmetric fracture growth.

with lengths on the order of 1000m closely matching the microseismic extents regardless of the degree of asymmetry. The consistency of the modeled lengths rules out apparent asymmetry resulting from monitoring biases. The variable asymmetry of the fractures about the injection points is likely a result of a stress shadow between stages. Finally, the 3D geomechanical models are able to provide the effective distribution of proppant placement along the primary hydraulic fracture planes.

Results from the geomechanical models can be populated into a reservor simulator to estimate the corresponding production and reservoir drainage. Additional sensitivity studies can help optimize the completion strategy for increased production. Alternatively, HCPV or TOC can be used as a proxy for reservoir qualtiy to compare different designs and maximize the fracture surface contact area. Operational costs can also be included to optimize the fracturing, completion and well design to maximize the well value. In this way, microseismic monitoring can be leveraged for operational improvements.

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