

Fractures, Elastic Moduli & Stress: Geological Controls on Hydraulic Fracture Geometry in the Horn River Basin

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Summary

Production from the shale gas reservoirs is dependent upon successfully stimulating these formations by creating hydraulic fractures. There are many examples from the US invoking the impact of geology (specifically rock mechanical properties, in-situ stress and natural fracture) and operational controls (fluid volume, sand volume etc) on hydraulic fracture geometry and ultimately production. The purpose of this paper is to demonstrate the connection between geology and hydraulic fracture geometry in the Horn River Basin.

The first portion of the paper introduces the general relationship between geomechanics and stimulation. We begin by addressing the theory behind the construction of in-situ stress profiles that provide the basis for fracture models. It will be demonstrated that changes in geomechanical rock properties such as Young's Modulus and Poisson's Ratio that influence borehole in-situ stress profile, and therefore the achievable frac geometry, are driven by changes in the depositional and diagenetic history of the Horn River shales. The effectiveness of a variety of in-situ stress models at predicating height growth will be discussed using microseismic data as a validation tool. Understanding the link between geological facies and geomechanical properties can be exploited during drilling to enhance the utilization of MWD Gamma Ray informed geosteering to insure that the lateral and vertical heterogeneity of the shale is used as a guide for proper well and frac stage placement.

The second part of the paper will introduce the concepts underpinning the notion of hydraulic fracture complexity with particular focus on the role of natural fractures. Some observations on the nature of the fracture systems present in the Horn River suggest they are multi-faceted, with multiple histories of generation and with diverse fills or open-porosity. Given this complexity, we performed a novel parametric study investigating the impact of fracture network properties on stimulated geometry in the Horn River. The results of the parametric study will be discussed within the context of the relative importance of, and interplay between, in-situ stress state and natural fractures in determining the final outcome of a hydraulic fracture treatment.

Introduction

Nexen Inc.'s Dilly Creek Project lies in the eastern half of the Horn River Basin of northeastern British Columbia (Figure 1). The prospective shale gas intervals are the Middle Devonian Muskwa, Otter Park and Evie formations which are comprised of siliceous, organic-rich shales (Figure 2). These shales are typically at a depth of 2200-2700m and can reach thicknesses as a complete section of over 200m. Beneath the prospective shale section are limestones and dolomites of the Lower Keg River Formation. The gas shales are overlain by the shales of the Fort Simpson Formation.

Exploitation of this resource requires multi-well pad development with each well having multi-stage hydraulic fracture treatments. Optimization of this "manufacturing" process requires resolving key unknowns surrounding well spacing, stage spacing, lateral well placement and hydraulic fracture design parameters (fluid volume, sand volume, rate, perforation strategy etc). We believe that the time and capital spent to achieve this optimization can be reduced by adequate characterization and modeling of the geological parameters that impact drilling and completion practices and outcomes. This paper will highlight the geological parameters that influence stimulation effectiveness in the Horn River Basin.

Geomechanics and Stimulation Concepts

While traditional concepts of bi-wing hydraulic fractures are described in terms of height, half-length and azimuth, a new paradigm has emerged for understanding the complex stimulation of low-permeability, fractured shales. For complex stimulation, hydraulic fracture geometry is now described as the height, length and width of a stimulated area as defined by microseismic monitoring (Figure 3). Different geological parameters control vertical height and horizontal shape (width and length, with the ratio referred to as the Fracture Complexity Index, Cipolla et al. 2008). The basis for understanding these controls from a geomechanical perspective will be provided.

Fracture Height

Fundamentally, hydraulic fracture height is governed primarily by in-situ stresses related to rock properties. Once a propagating fracture reaches a horizon where the stress contrast is greater than the net pressure in the fracture it will arrest (Simonson et al., 1978). The equation at the heart of height prediction is the standard stress equation.

$$\sigma_{\text{hmin}} = \frac{\nu}{1-\nu}(\sigma_v - \alpha p) + \alpha p$$

Where:
 σ_{hmin} = Minimum horizontal stress
 σ_v = Vertical stress from overburden
 ν = Poisson's ratio
 p = reservoir fluid pressure
 α = Biot - Willis Coefficient

(modified after Eaton, 1969)

When broken down into its constituent elements its states that the minimum horizontal stress at a point in the earth is a function of the effective weight of the overburden that is transmitted into horizontal plus the stress induced by pore pressure at that point. How much of the effective overburden load is transmitted into the horizontal is a function of the Poisson's Ratio. The value of Poisson's Ratio is typically related to such characteristics as lithology, fabric, porosity, cementation, etc.). Assumptions for this equation include that media is isotropic and that there are no additional tectonic forces. In the case of shales, often being layered and having large differences in composition, the isotropic media assumption must be modified. Furthermore, tectonic forces are often evident in interior basins and must be accounted for in the stress profile.

This equation can be modified to account for rock property anisotropy and tectonic forces in a manner consistent with linear elastic fracture mechanics. Anisotropy can be measured for Young's and Poisson's moduli transverse or along shale fabric as well as vertically and horizontally by sonic logs. Tectonic forces also must be accounted for and this is done by calibrating to measured minimum horizontal stress from well tests (DFITS). Using data from the Horn River shales, the importance in properly modifying the standard stress profile correctly to identify potential barriers to height growth will be demonstrated.

Length/Width (Complexity)

Much of the early microseismic work in the Barnett Shale revealed the variety of hydraulic fracture geometry in shale. Many studies since make a case that stress anisotropy and the nature of a natural fracture system are the key geological drivers to this complexity (Gale, 2007). The interaction between in-situ stress, natural fractures and pumping pressures creates complex fracture paths that can utilize natural fractures for propagation. Rock failure is dependent on geological parameters such as tensile strength, cohesion of natural fractures, and friction (if the natural fractures are not healed). Many models of failure are used in trying to understand complex hydraulic fractures. For example, if the rock matrix fails as a tensile fracture, the propagating hydraulic fracture will interact with existing natural fractures based on the tensile strength and friction (Gu and Wang, 2010). Healed natural fractures will reactivate and open when the process zone stress at the hydraulic fracture crack-tip is of sufficient magnitude to overcome the cohesive strength of the fracture and cause slippage. If the tensile strength of the rock is less than that required to cause slip along the fracture then the hydraulic fracture won't "see" the natural fracture and will propagate through it (Cipolla et al 2011). Once open fluid pressure builds to a sufficient level in the fracture to overcome fracture toughness that natural fracture can open and extend. Furthermore, given sufficient fluid pressure build up and the right stress state, shear failure of the fracture can occur (Dershowitz et al. 2010). At some point natural fractures terminate and this may induce new hydraulic fractures at the tip e.g a wing crack (Gale et al, 2007). Similar failure can occur if hydraulic fracture induced fluid pressure is propagating in an open natural fracture system. Typically in this scenario certain orientations of fracture will preferentially reactivate in shear depending on the effective in-situ stress tensor.

The variability in the patterns of complex hydraulic fracture patterns can happen locally, even within the same borehole. Variations in stress anisotropy, defined as the difference between maximum and minimum horizontal stress magnitudes, is often used explain differences in complex geometry (Ketter, et al., 2008). Typically, a constant natural fracture pattern (often orthogonal) is the frame to vary the stress anisotropy. Others have tried to utilize discrete fracture network models (DFN) to investigate how changes in the spacing, orientation, length and connectivity of natural fractures can create significantly different complex hydraulic fracture regions (Rogers et al., 2010). We will provide examples of incorporating in-situ stresses with a DFN to understand the complex hydraulic fracture stimulation observed in the Horn River shales. This study reveals that the interplay of fracture system connectivity (a function of intensity and size), the presence and properties of fracture fill and the in-situ stress state are the key geological variables to understand.

Observations from the Horn River

Fracture Height

Figure 4 shows the relationships of elastic moduli to other geological properties & the in-situ stress profile for a well in the Horn River. What can be seen is that, similar to other shale plays, the mineralogy, (particularly the volume of clay) has a strong impact on the moduli. Young's Modulus decreases and

Poisson's Ratio increases in these clay rich units of the Fort Simpson and lower Otter Park Formations. Anisotropy, as calculated from the Sonic Scanner data, appears to be confined to these units. Incorporating the anisotropic moduli into the formulations of the stress equation clearly indicate the strong possibility of containment, significant amounts of microseismic data acquired to date in the play support this (Figure 5). Given the strong anisotropy it would be thought that increased layering would be visible in the rock. A Textural Classification Index (TCI) was created from image logs at the ten centimeter scale (Figure 4a). Perhaps surprisingly there was no correlation of high index (high degree of layering) to anisotropy and there was not a strong relationship to any one log measurement. A similar index was developed for thin section and SEM images which showed a clear correlation to lithotype, with silty and argillaceous mudstones having materially higher indices than siliceous, dolomitic and calcareous mudstones. Core Plug scale measurement of anisotropy, summed into the K_0 parameter, confirm the relationship between lithotype and anisotropy. This may seem to suggest that it is always necessary to run specialized logging tools and/or core in order to ascertain the presence and degree of anisotropy with reasonable certainty. In reality it indicates that if you understand the distribution of lithotypes in your reservoir then you can be predictive about mechanical behaviour. The correlation, for example, between the Uranium/Thorium Ratio (an indicator of terrigenous influence that is likely to produce a distinctive lithotype) and anisotropy is apparent in Fig 4a.

The risk of reducing the amount of static data collection is that lateral facies changes in the reservoir may not have been sampled sufficiently. A cursory glance at logs across the basin show that large scale facies change is clearly present particularly in the Otter Park. Seismic, particularly inversions for geomechanical parameters, can be useful to the limits of its resolution and uniqueness of solution in the identifying of different geological character that could impact hydraulic fracture geometry. However in aiming for a 100% success rate in frac initiation and sand placement attention must be paid to the frac stage scale. In this regard geosteering becomes a tool to aid in optimizing both drilling and completions. If sufficient attention is not given to the stratigraphic position of the horizontal wellbore at any given point, what is actually moving up or down in section (vertical heterogeneity) due to structure could be misconstrued as lateral heterogeneity. Correlation using the MWD GR to the nearest well where mechanical data exists can quickly reveal if such movements of the wellbore will result in negative completion implications and thus avoid the need to run expensive mechanical or lithologic logs in open or cased-hole horizontals.

Width/Length (Complexity)

Microseismic monitoring of multiple hydraulic fracture stimulations performed with the same design parameters has identified a spectrum of length/width geometries in Horn River from highly complex to long and linear (Figure 6). In order to be able to understand and try predict the mechanisms behind the varying geometry (both design and geological) it was necessary to first characterize the natural fracture system and define the in-situ stress tensor.

Natural fractures, healed and open, are readily identifiable in the Horn River in core, image log and outcrop (Figure 7). Using these sources of information it has been determined that many of the fracture key properties mentioned are variable in the vertical section and along a wellbore. This therefore introduces a further level of heterogeneity. Density, sonic and image logs and DFIT's have been utilized to estimate the orientation and relative magnitudes of the three principle stresses in the Horn River. A normal regime was originally identified but the pattern of drilling induced fractures in horizontal image logs indicate parts of the reservoir being on the cusp of a strike-slip regime. Therefore relative to plays like the Barnett the stress regime in the Horn river is potentially more anisotropic (maximum horizontal stress significantly greater than minimum horizontal stress) yet highly complex hydraulic fractures are common (Figure 6)?

Complex Hydraulic Fracture Modeling

With this fracture and stress data a parametric study was undertaken using DFN model and Finite/Discrete Element (ELFEN) software (Rogers et al, 2010) to determine if the range of different microseismic patterns observed in over 150 fracture treatments could be reproduced for the given stress field by varying natural fracture system parameters only. The results (Figure. 8) clearly show that “isotropic” or “weakly anisotropic” hydraulic fracture complexity patterns can be created in an anisotropic stress regime.

Lateral variation in spatial organization of natural fractures (e.g. clustering) is a common occurrence in rock (Odling et al. 1999). In the Horn River it is likely that the frequency of such clusters may occur on scales smaller than common lateral well lengths. Therefore it appears that the modeling results are a geologically reasonable explanation for variance in frac length/width geometry along a wellbore targeted in a horizon where variation in mechanical properties can be reasonably said to vary little. Furthermore if the mechanical conditions under which the natural system formed correlate to the present day mechanical stratigraphy it may be reasonable to assume that the influence of a fracture swarm could apply for most or all of the height of the stimulated zone. If a lateral facies change is encountered in a horizontal in the targeted horizon that would result in a relative change in the magnitudes of the principal stress (becoming more or less anisotropic) the impact of that on the complexity of the frac geometry through the entire section is difficult to conceptualize. A facies change would need to occur at the same point through out a vertical section that represents different depositional conditions under varying sequence stratigraphic positions.

Conclusions

The depositional setting and diagenetic history of shale gas packages such as the Muskwa/Otter Park and Evie Formations have inherent heterogeneity as a consequence of depositional, diagenetic and structural factors. This heterogeneity has been shown to impact the hydraulic fracture geometries achieved in the Horn River from both a height and complexity standpoint. Core, well log and seismic data are available to capture this heterogeneity at a variety of scales. It is suggested that acquisition of some of this data can be reduced when it is combined with insight from outcrop observations, standard drilling acquired data and geological concepts surrounding sequence stratigraphy and spatial variation in fracture systems to predict changes in the reservoir that may impact (positively or negatively) hydraulic fracture geometry.

Key conclusions are:

- Anisotropy in geomechanical parameters is present in specific facies and when properly input into the borehole stress profile allows for the identification of barriers to hydraulic fracture height growth.
- Natural fractures, both healed and open are present in the Horn River and reactivation and failure of both during stimulation is a dominant geological mechanism for controlling stimulated area complexity within a consistent stress field.

Acknowledgements

The authors would to thank Nexen for permission to present this work and the Shale Gas team including Doug Beringer and Jon Dola for their contributions. We also thank Steve Rogers of Golder Associates for his work on hydraulic fracture modeling using Fracman®.

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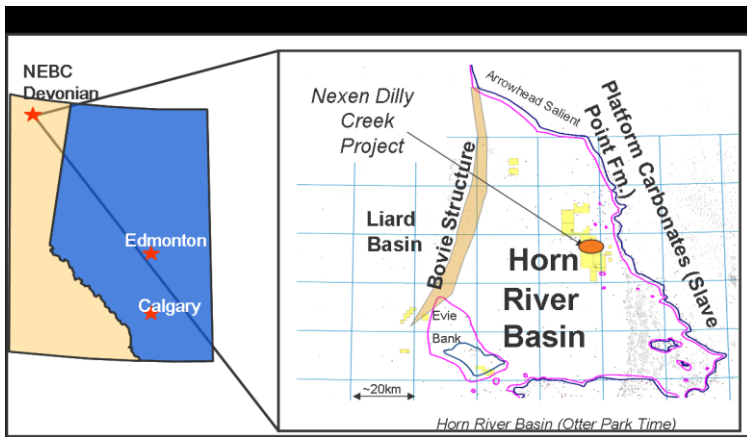


Figure 1. Location and outline of Horn River Basin play Nexen Inc., Dilly Creek project highlighted in yellow

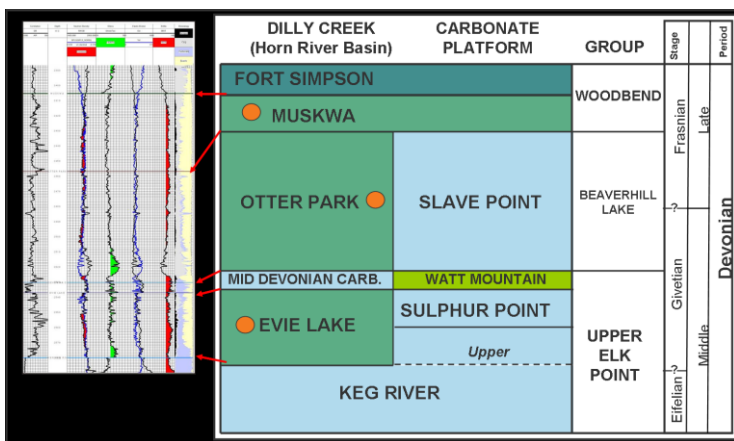


Figure 2. General Stratigraphy of the Horn River Basin (after Ross & Bustin, 2008). Dilly Creek Type Log shown on left. Targeted Horizon shown by discs

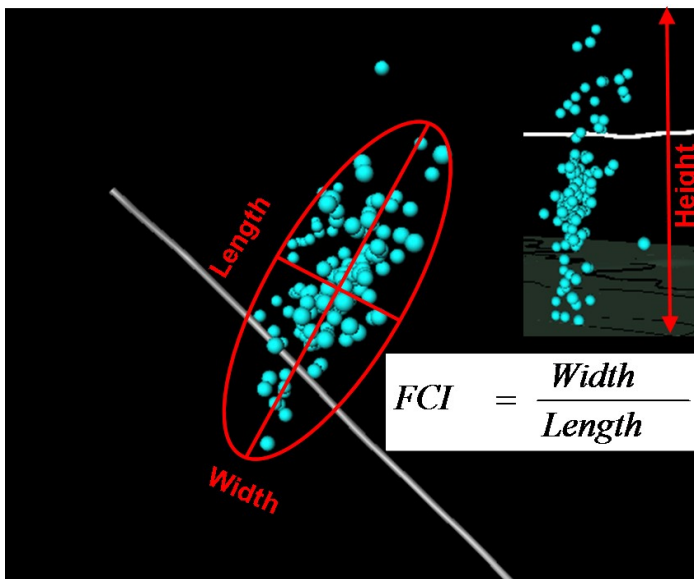


Figure 3. Height, width and length of a microseismic cloud example from Dilly Creek. A simple ratio, of length to width can be calculated to give a first order characterization of complexity called the FCI. In this example the value is 0.34, which is similar to published Barnett shale examples (Cipolla et al. 2008),

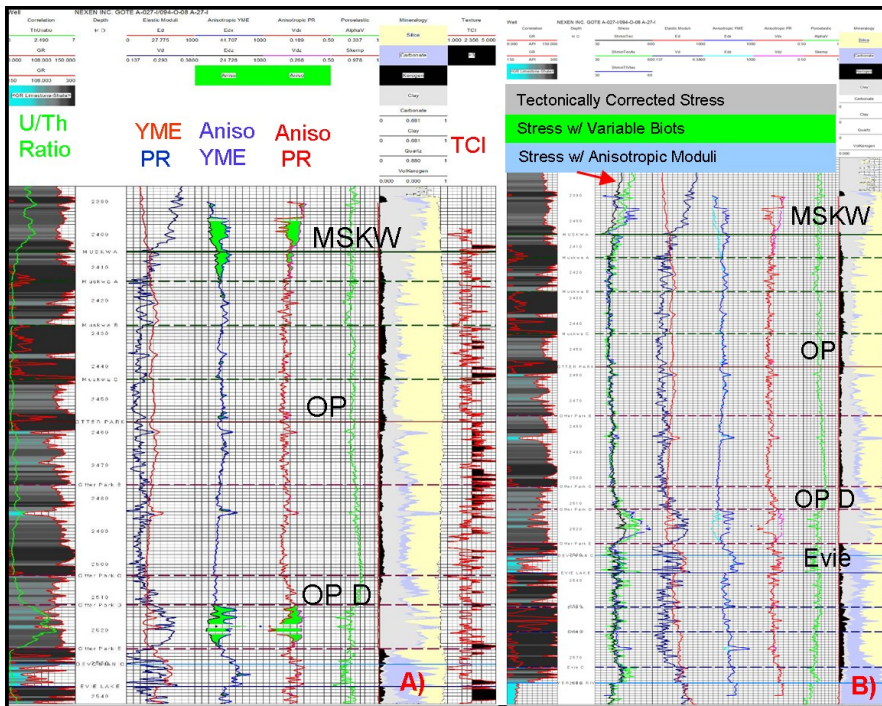


Figure 4. a) Anisotropic mechanical property log for Dilly Creek well showing relationship to mineralogy and stratigraphic horizon. b) In-situ stress profile generated using different assumptions showing high stress contrast related to certain facies. MSKW-Top Muskwa, OP –Top Otter Park, OP D – Top Otter Park D, TCI-

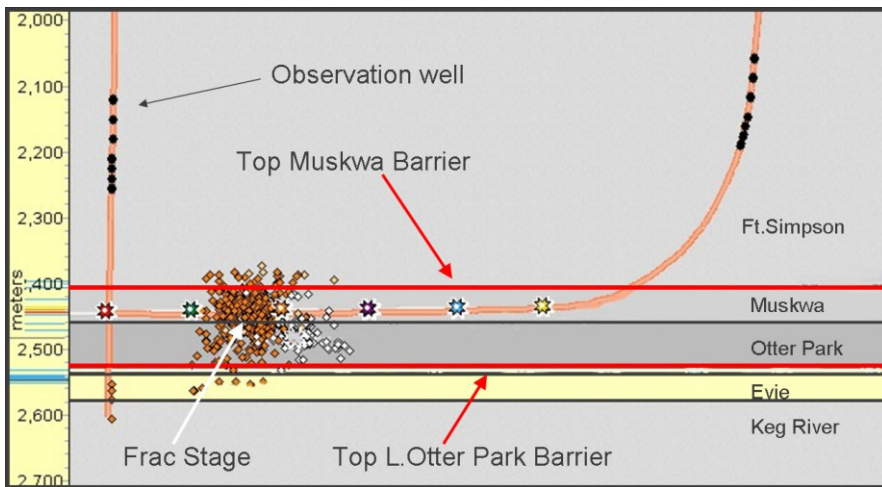


Figure 5. Typical vertical microseismic geometry for Dilly Creek showing containment at the Fort Simpson and Otter Park D.

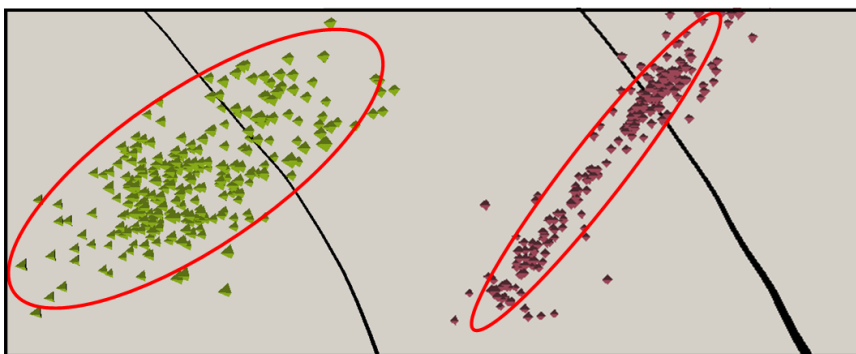


Figure 6. Example of complex and linear hydraulic fracture geometries resulting from stimulations in the Horn River

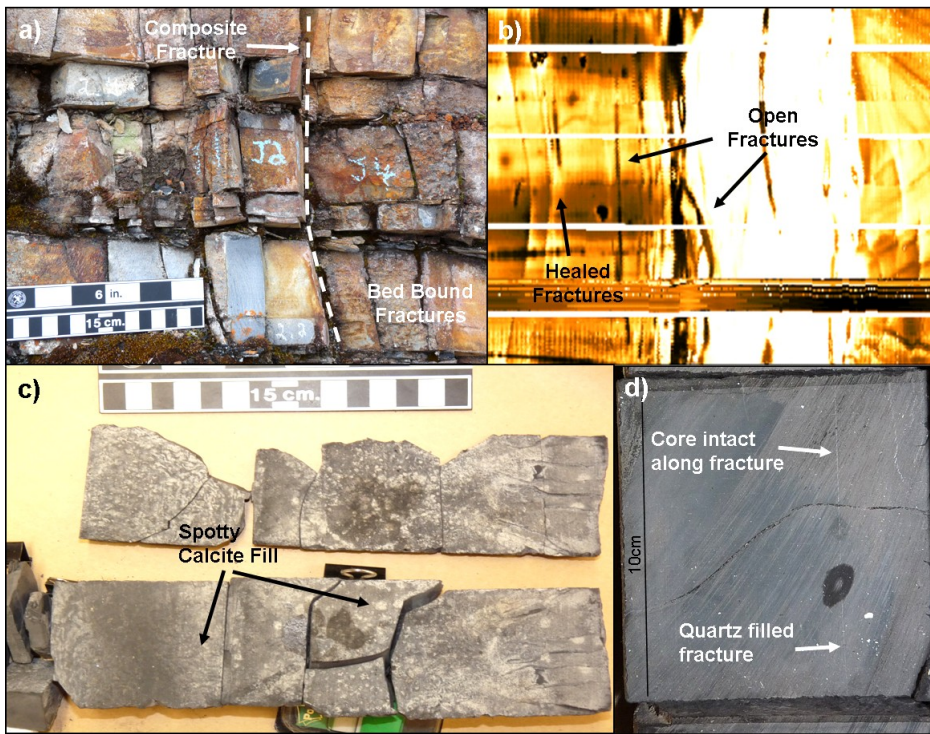


Figure 7. Small-scale examples of fracture information. **a)** Northeast BC Devonian sh outcrop showing multiple fracture sets. Image log data in a horizontal well through the Muskwa/Otter Park formation. Core c showing **c)** partially open and **d)** closed fractures in the Muskwa/Otter Park formation.

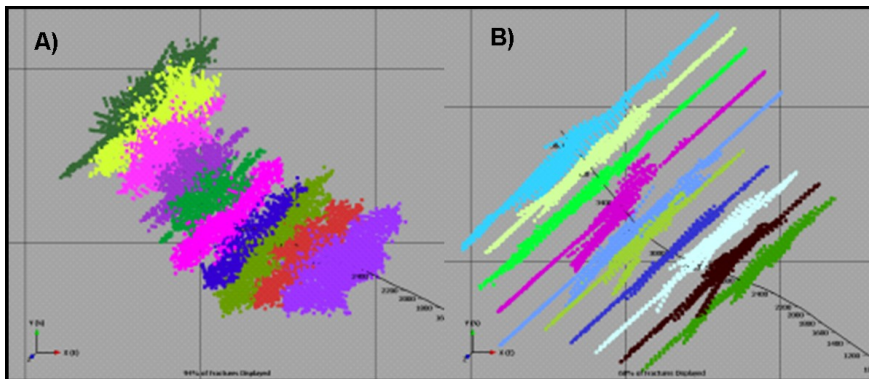


Figure 8. Simulated microseismic patterns on Horn River well produced from hydraulic fracture modeling in Fracman®. A) Complex hydraulic fracture pattern resulting from a well connected natural system (high intensity, long fractures). B) Linear hydraulic fracture pattern resulting from low connectivity natural system (low intensity, short fractures). Stress magnitudes and direction and pore pressure are the same for both cases.