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Fault Re-activation Predictions: Why Getting the In-situ Stresses Right Matters

Patrick J. McLellan
McLellan Energy Advisors Inc.

Summary

Deterministic fault re-activation analyses can be a valuable tool for making predictions of induced seismicity risk associated with hydraulic fracturing or waste water disposal. This paper reviews many of the common modelling approaches with this class of geotechnical tools and highlights some of the limitations of the simple analytical models that do not capture all the relevant physics, e.g., poro- and thermo-elastic effects, "stress shadows" created during hydraulic fracture treatments, and realistic fault friction coefficients. Using recent data from a well-characterized field in the Montney Formation, NEBC, the sensitivity of fault re-activation during high pressure injection is investigated for the range of measured minimum horizontal in-situ stresses and pore pressures from 32 DFIT or mini-frac tests. The importance of site-specific geomechanical data for making confident predictions or post-failure analyses is demonstrated.

Introduction

Fault re-activation is a classic rock mechanics problem treated in many branches of applied earth science – seismology, engineering geology, civil geotechnical engineering, structural geology, mining and petroleum engineering. Invariably there are issues of data availability and its quality when it comes to characterizing in-situ stresses, pore pressures, rock mechanical properties and fault geometry. A deterministic assessment of induced seismicity risk for a known fault structure may have a low predictive confidence for these reasons. Similarly Probabilistic Seismic Hazard Analyses (PSHA), which are more popular with many seismologists, also have limitations due to data quality, variability, if it exists for a given setting, and local shallow geological differences. First-order deterministic predictions of fault re-activation potential are relatively simple to perform with readily available software, and represent a viable way to first investigate a potential issue. When a local setting has been more fully characterized with core, logs, well tests and seismic to define in-situ stresses, pore pressures, mechanical properties and fault geometry it may be appropriate to assess fault re-activation with more flexible numerical geomechanical models that allow for complex geometries, non-linear properties, and transient effects. These sorts of fault stability analyses have application not only to induced seismicity arising with waste water disposal, but also hydraulic and acid fracturing, carbon sequestration, enhanced oil recovery, and hydrocarbon production.

Methodology

The Mohr-Coulomb failure analysis represented with a simple diagram is often used to display the factors affecting slip on a plane in a triaxial stress state. The basic mechanics of the problem can be found in most classic rock mechanics textbooks, such as Jaeger and Cook (1979). Researchers have extended this procedure for different rock types with non-linear or bilinear failure criteria. At low effective stresses, especially in weak materials like poorly cemented sandstones or weak shale, the failure envelope may deviate from a straight line, reflecting a lower tensile or cut-off strength. A comparison of analytical and numerical failure models, which are based on a simple or more complex Mohr-Coulomb criteria, is given in the presentation.

Several different metrics have been used to assess the “critical” stress condition or essentially when the shear stress on a fault exceeds the its strength, e.g., slip tendency, modified slip tendency, factor of safety to failure, critical pressure perturbation, critical failure function, or similar. These deterministic models can be broadly classified as being either analytical (single plane or field scale); general purpose numerical models; or specialized, seismological models for assessing earthquake risks at a very large scale on multiple connected faults, such as over 100’s or 1000’s of kilometers.

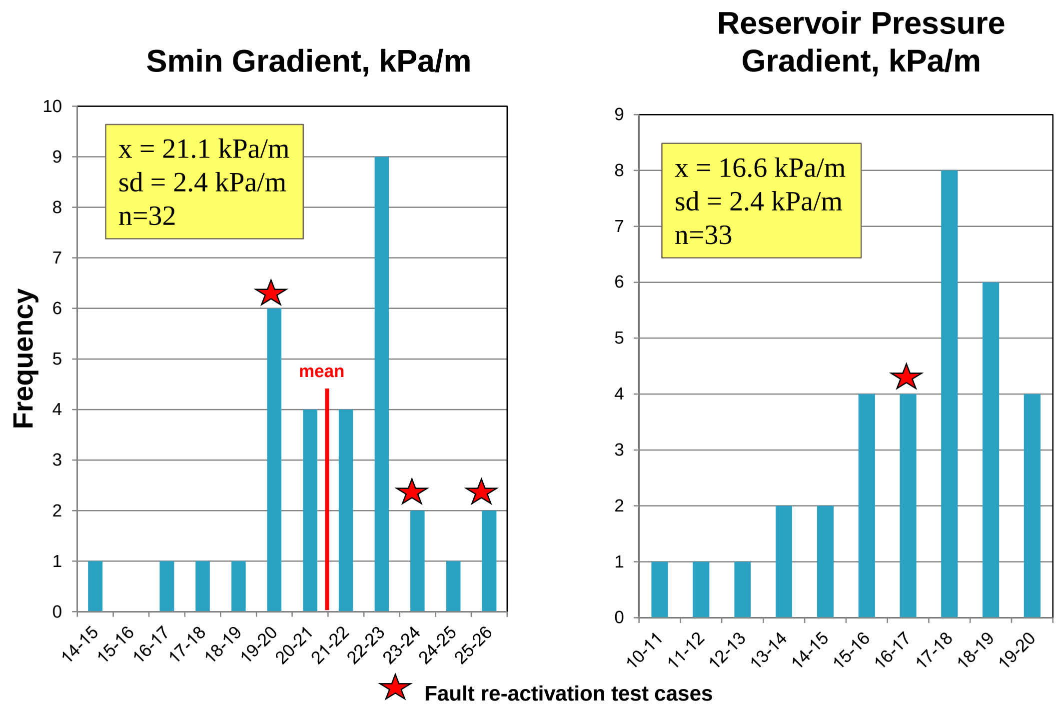
Invariably in practice one is faced with the question – When is a simple model for the re-activation problem adequate for the intended purpose, whether that be assessing fault risk before injecting or producing, or analyzing a known seismicity event where fault specific information has been obtained.

With a growing interest in the mechanics of multi-zone stimulation behaviour in the last decade researchers in industry and academia have investigated several of the following factors that are believed to affect fault re-activation in a given setting:

- Poro-elastic or “stress path” effects, i.e., for situations where we inject into or produce from permeable reservoirs, that leads to vertical and horizontal total and effective stress changes,
- Thermo-elastic effects, similar to above, where colder or warmer fluids are injected into permeable or impermeable formations,
- “Stress Shadow” effects arising during the hydraulic fracture stimulation of low permeability, unconventional resources,
- Fault friction behaviour as measured on real fault materials, at representative strain rates, effective stresses, and fluid saturation conditions. The common assumption of a fault friction coefficient of 0.6, contrasts with actual values from the laboratory that can range from 0.4 to 1.0,
- Non-uniform and transient fluid pressure distributions along a single fault or network of faults

This presentation will demonstrate, with the relatively simple linear Mohr-Coulomb fault re-activation criteria used in the geomechanical software STABView (2008), the sensitivity of the critical injection pressure gradient (commonly referred to as the “frac gradient”) to changes in the far-field in-situ stress magnitudes, fault orientations, and fault friction angle.

Fig 1



Data from McLellan et al, GeoConvention, Calgary, 2014

Example Analyses

McLellan et al (2014) reported the results of a comprehensive DFIT or mini-frac testing program on 32 horizontal wells in the Farrell Creek Montney Formation of NEBC. Fig 1 shows the distribution of the fracture closure pressure (FCP) or Smin determined from these tests which were conducted at very similar injection rates, with similar volumes in the toe stages of these wells, typically through 3 perforation clusters. Identical FCP and ISIP selection procedures as described by McLellan at al (2013) were used to analyze these tests. Note the considerable variability in Smin across this field, which has been affected by both thrust and normal faulting of Laramide and Permian ages, respectively. For all but two of the DFIT tests the Smin values are less than the calculated vertical stress from bulk density logs, hence these tests have provided the minimum horizontal in-situ stress, SHmin. The two tests with Smin gradients greater than 25 kPa/m suggest horizontal hydraulic fractures were produced in excess of the vertical stress, Sv. Similar to the Smin distribution, the pore pressure gradients derived from 32 DFITs and one build-up test have a wide distribution from 10 to 20 kPa/m, which is thought to reflect structural effects in this faulted field, and to some extent, uncertainty in the pore pressure value determined after one or more weeks until the point where pseudo-radial flow conditions are commonly interpreted. Red stars are used on the Smin and reservoir pressure histograms to show three in-situ stress states selected to analyze fault re-activation risks.

Fig.2

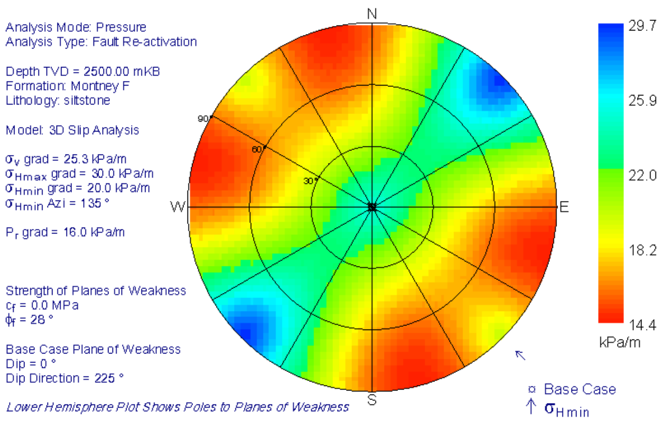


Fig. 3

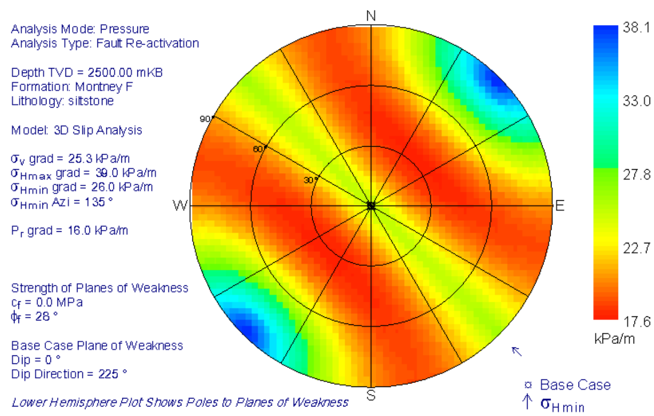


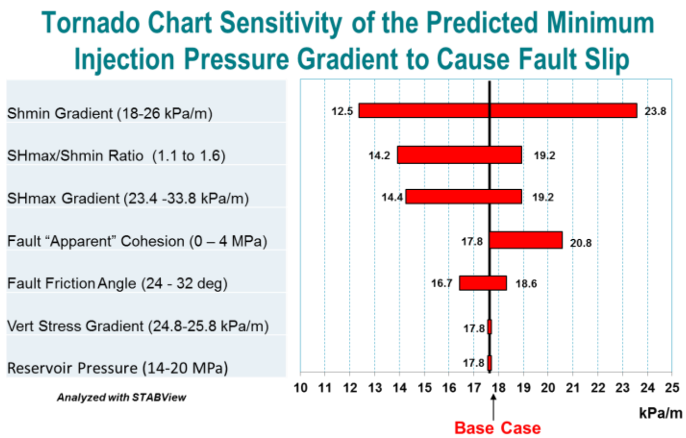
Fig. 2 is a lower hemisphere colour polar or stereonet plot of all possible poles to fault planes contoured with values of the injection pressure gradient required to cause slippage. The input data on in-situ stress magnitudes and orientations, pore pressures, fault cohesion and friction angle are also shown for this analysis. This would classify as a strike-slip fault stress regime based on the assumed stresses. Poro-elastic effects due to injection have been ignored for this example. The dark red regions on the plot reflect the faults with the lowest injection pressure gradients at this depth (~14.4 kPa/m) which would result in fault slippage. Vertical faults striking at N75°E and N15°E are the most critical, ie., they are prone to slipping at the lowest injection pressure.

Fig 3 shows a different looking polar plot but this time with an assumed thrust fault stress regime, that would be indicative of the rare Smin data for two wells suggesting horizontal hydraulic fractures were produced. In this case the pattern of injection pressure gradients required for all possible fault poles looks quite different from Fig 2. The most “critical” fault orientations would possess azimuths NW-SE and dip at 30° to the NE or SW, each of which would slip at an injection pressure gradient of ~17.6 kPa/m. Hydraulic fracture treatments had bottomhole injection pressure gradients in excess of 25 kPa/m for most of the field.

Fig 4 is a tornado chart for this same problem showing the relative sensitivity of various plausible in-situ stresses, pore pressures and mechanical properties.Note the most sensitive input parameters are the SHmin and SHmax gradients, followed by the “apparent” fault cohesion, and then the fault friction angle.The small range of vertical stress gradients, as calculated for this area from bulk density logs, shows this parameter is less significant for causing fault re-activation.

A set of 12 direct shear tests were conducted in the laboratory to measure the coefficient of friction on failed and intact bedding planes in Montney siltstones at effective stress levels representative of high pressure injection during stimulation treatments used in the field (McLellan, 2012; McLellan et al, 2014). A friction coefficient of 0.5 was the average of all the tests along or across bedding. Even this small difference from the typical assumed value of 0.6 will mean that several natural fracture sets or faults in the very over-pressured field are already in “critical” conditions even before injection commences (Rogers et al, 2014).

Fig. 4



Conclusions

1. For deterministic fault predictions simple slip-on-a-plane models are the recommended starting point to understand the problem and perform a first-order analysis of the most important causal factors.
2. Horizontal in-situ stress differences drive the fault re-activation problem in typical, over-pressured strike-slip fault stress regimes of the Montney Formation in the Farrell Creek area of NEBC.
3. For more reliable fault re-activation analyses the minimum horizontal stress should ideally be obtained from mini-fracs. Poro-elastic, thermo-elastic and “stress shadow” effects should be accounted for, where possible.
4. There are rare cases where low angle bedding planes can be inflated and sheared during hydraulic fracture operations in thrust fault stress regimes, i.e., $\sigma_3 = S_v$
5. For a given 3D seismic derived fault geometry the relative importance of the input data for a basic fault re-activation analysis is: *Stresses* > *Fault Properties* > *Injection Pressure* > *Elastic Properties*

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