Using Microseismicity to Identify and Verify Increased Fracture Complexity During Hydraulic Fracture Stimulations

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Summary

We examine microseismicity associated with hydraulic fracture stimulation in a naturally fractured shale formation. The stimulation program was designed to assess the potential for increasing fracture complexity by considering the number of perforations, injection pressure rate changes, and different fracture hesitation approaches. In addition to event locations, multi-array and multi-well configurations allowed for the assessment of general moment tensor solutions for the observed events. This approach provided an opportunity to examine the relative spatial and temporal behaviour of fracture orientations (azimuths and dips) as a function of the stimulation program. In general, derived fractures typically grouped into two orientations (sets), similar to mapped natural fractures or secondary (induced) fractures. Reducing the number of perforations resulted in increased fracture variability and complexity whereas sequential failure of different mapped fracture sets occurred as a result of pressure rate changes. Our results also suggest that the hesitation approaches achieved their objective, with the dominance of natural fracturing early in the sequence as compared to induced fracturing upon re-injection, a direct result of localized stress re-orientation during the stimulation. Our observations suggest that varying the stimulation program can potentially be used to control fracture complexity and potentially result in a direct impact on stimulation effectiveness.

Introduction

Microseismic monitoring is routinely being used to identify overall hydraulic fracture characteristics such as geometry, half width, stage overlap, and estimated stimulated reservoir volume. Engineers utilize these data along with engineering data to assess the effectiveness of a stimulation program, improve drainage, and ultimately increase production. Inherently, microseismic signals contain information about the physical processes at the source (event origin). By utilizing techniques such as Seismic Moment Tensor Inversion (SMTI) analysis (Baig and Urbancic, 2010), additional source characteristics such as the principal strain axes, failure mechanisms, and potential fracture plane orientations can be determined.

Solving for SMTI derived parameters is not trivial and numerous papers have been written discussing various approaches, models, and methods of assessment of validity. All approaches require that the events being examined are sufficiently surrounded by a three dimensional network of measuring points (network of sensors). For hydraulic fracture stimulations, access in many cases restricts the coverage, however, multi-array multi-well array configurations can provide sufficient coverage, as determined through condition number analyses, to solve for the failure components of individual events.

One of the more interesting potential uses of SMTI data is in the evaluation of the effect different stimulation approaches have on fracture development. For example, an approach being investigated by numerous producers, referred to as hesitation stimulations, in theory can be used to create a dendritic (branching) fracture network to enhance well productivity (up to 2 to 5 times over conventional fracturing) and to rapidly drain the reservoir around a wellbore as compared to bi-wing fractures (Kiel, 1977). The process uses a cyclic injection procedure by shutting the well in or allowing it to flow back, and then resuming injection to open secondary fractures offset from the initial primary fracture orientation. Similarly, changes in injection pressure rates, the number of perforations, slurry rates may result in variations in local stress conditions that potentially can affect the type of fracturing, the fracture intensity and overall fracture complexity associated with a particular stimulation program.

In this paper, we examine microseismicity associated with a stimulation designed to assess fracture complexity in a naturally fractured shale formation. In particular, the stimulation program considers the number of perforations, injection pressure rate changes, and different fracture hesitation approaches. In addition to event locations, multi-array and multi-well configurations allowed for the assessment of general moment tensor solutions for the observed events. This provided an opportunity to examine the relative spatial and temporal behaviour of fracture orientations (azimuths and dips) as a function of the stimulation program. Based on these analyses, we discuss how augmenting observations of microseismicity with moment tensor derived fracture data can be used to assess the effectiveness of different fracture stimulation programs as evidenced in this study.

Analysis

Our analysis is focused on examining the stimulations associated two long horizontal wells in naturally fractured shale. Three arrays were deployed consisting of a minimum 16 -24 triaxial 15Hz omni-directional geophones magnetically clamped in a vertical observation well along with additional 24-level multi-point arrays in the vertical and horizontal sections of nearby wells. Based on the condition number analysis as outlined by Urbancic et al., 2010, the arrays were positioned meet the prerequisites for obtaining general solutions. General solutions with low condition numbers were used in the determination fracture orientations, utilizing an approach similar to that proposed by Gephart and Forsyth (1984). Individual fractures showing consistency between general and double couple solutions were retained for further analysis. Overall, our analysis considers ~6200 events for 10 stages of the stimulation associated with 2 horizontal wells located within ~800 ft. to each other (See Figure 1).

The stimulation program consisted of different approaches. In Well 1, with the exception of Stage E, the stages consisted of at least four perforations, whereas a more varied program was considered for Well 2, consisting of 3 and 4 perforation stages as well as two stages that included hesitation intervals of a few hours and over one day. Included in Figure 1 are rosette diagrams showing the orientation of SMTI derived fractures with dips greater than 60 degrees (Note: over 90% of the observed events were associated with steeply dipping fractures). Also included on Figure 1 are the fracture orientations mapped from core just to the south of the study area. These fractures can be classified into two groupings, those referred to as natural fractures developed during paleo-stress conditions and those induced by core drilling (secondary fractures) developed under the current stress regime. Generally, the natural fractures trend NW-SE and are steeply dipping whereas the induced fractures trend NE-SW and are also steeply dipping.

In general, the observed fracturing for the early Well 1 stages are dominated by fractures similar to the mapped natural fracture network. Observed differences between the mapped and derived fracture orientations are likely related to a slight re-orientation of the regional stress field between the data collection sites. However, the observed consistency in orientation suggests that the stimulation has activated the pre-existing natural fracture network. Stages A to D in Well 1 all exhibit primarily NW-SE trending fractures. These stages were completed based on utilizing four perforations. In contrast, Stage D in Well 2, also a four-perforation stage, the fracture network appears to be dominated by activated secondary fractures and to a smaller degree natural fracture. These differences are likely due

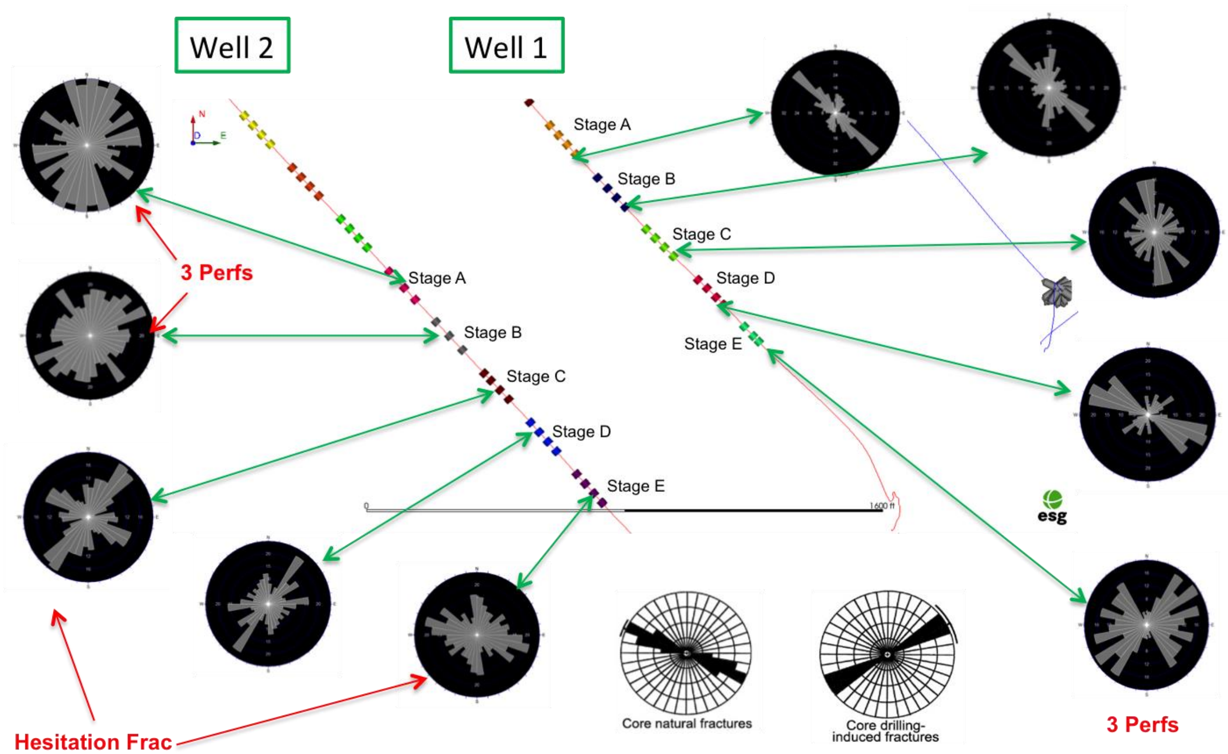


Figure 1. Plan view of well locations along with the rosette diagrams for the SMTI derived fractures for each stage. Additionally, the mapped natural and induced (secondary) fractures are also shown on rosette diagrams. Unless indicated, each stage consisted of four perforations. North direction is towards the top of the figure.

to the proximity of the stages to nearby or previously fractured areas and thereby the observed fracture network is likely related to local re-orientation of the stress field. For Well 1, Stage E, three perforations were used and interestingly, the observed fractures are widely distributed, resembling a 'starburst' pattern. This is very similar to what was observed for Stages A and B for Well 2, also three perforation stages. It appears that stages with fewer perforations resulted in starburst fracturing with therefore a significant increase in associated fracture complexity.

In Figure 2, during the stimulation of an early stage in Well 2, a change in injection pressure occurred during the stimulation. If we consider the events prior to the pressure change, fractures generally trend NE-SW whereas following the pressure change, most of the fractures are oriented NW-SE. In referring back to Figure 1, it appears that the pressure change was sufficient to active the natural fractures subsequent to the initial activation of secondary fractures. This suggests that the degree of fracture complexity, fracture lengths and widths associated with different stimulation programs can be verified through SMTI analysis.

Similar in concept are the hesitation fracture stages in Well 2 (Figure 3; Stages C and E). The hesitation stimulation programs were effectively the same, with the exception of the duration of the flow back time associated with the cyclic injection. In either case, the hesitation approaches resulted in observed differences in fracture orientations prior to and post the flow back interval. Prior to flow back, activated fractures were dominated by singular fracture sets, either trending ~E-W or NE-SW.

Following the flow back interval, activated fractures include the initial pre-flow back fracture set and a dominant secondary fracture set. Based on these observations we can speculate that local re-

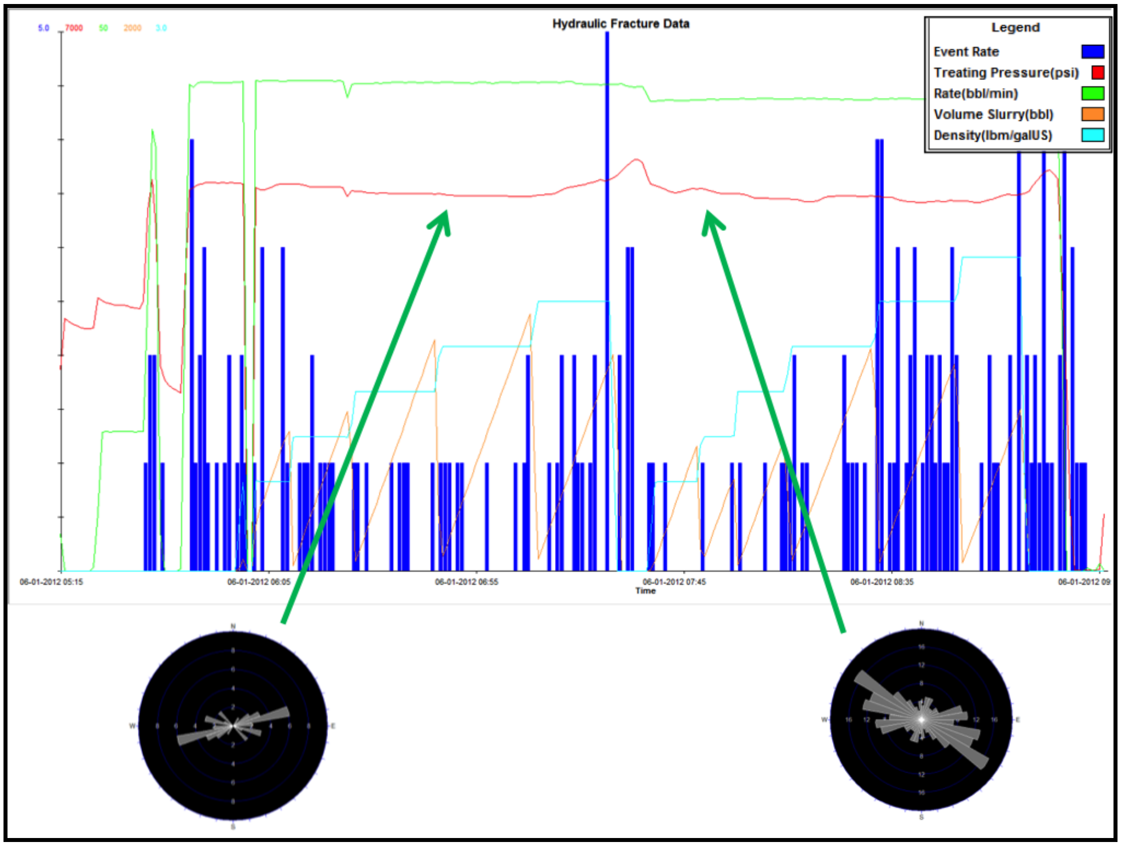
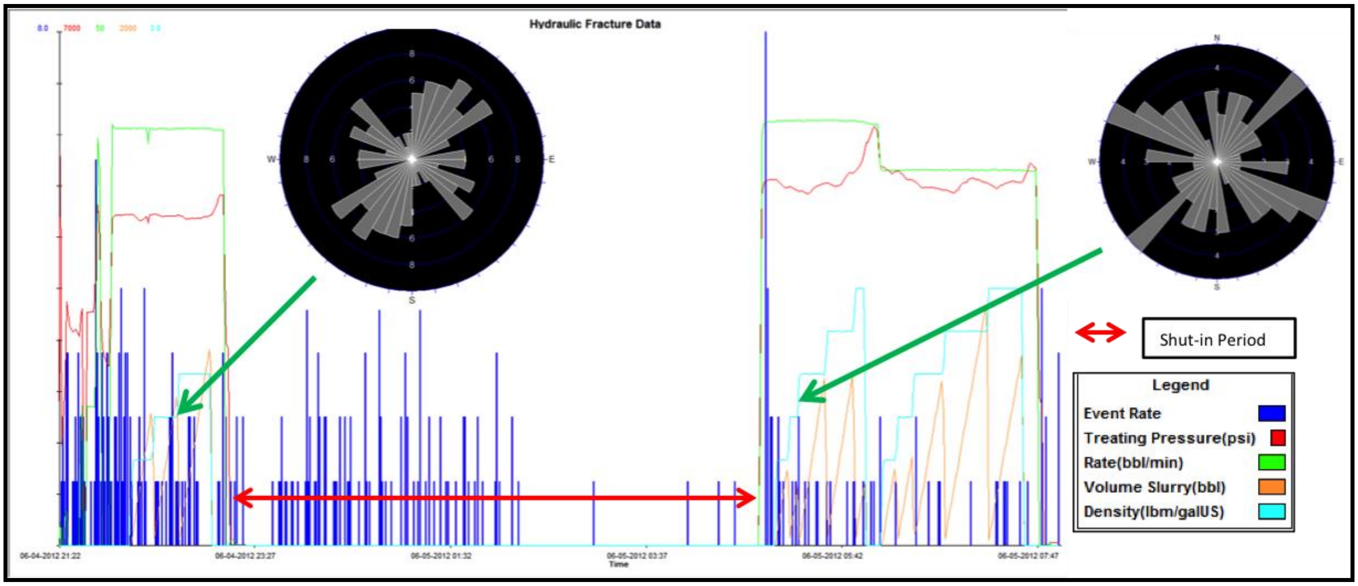


Figure 2. Early Well 2 stage showing re-orientation of the fracture set as a result of injection pressure changes (red) during the stimulation.

orientation of the stress field as a result of the pre-flow stimulation allowed for the activation of a secondary fracture set. The continued activation of the initial fracture sets suggests that differences in failure mechanisms may be occurring, where previously opened fractures are exhibiting closure. In both cases, the level of fracture complexity has increased as a result of the hesitation process. In the future, the effectiveness of the created transport network is to be examined as part of a study of the failure mechanisms.

Conclusions

In this study we have examined how different fracture sets associated with stimulation of a naturally fractured shale formation are activated by differences in the stimulation program. Specifically, we examined the response in fracturing based on the number of perforations, injection pressures and cyclic hesitation style of stimulation. The objective of the program was to assess the potential for increasing fracture complexity. In general, derived fractures typically grouped into two orientations (sets), similar to mapped natural fractures or secondary (induced) fractures. Reducing the number of perforations resulted in increased fracture variability and a starburst pattern in fracturing rather than specific fracture orientations. Increases in fracture complexity where also observed, however, through the sequential addition of fracture sets, resulting from both pressure changes and cyclic injection programs. Our results suggest that the stimulation programs achieved their objective of increasing fracture complexity through the re-orientation of the localized stress field during the stimulation. Our observations suggest that varying the stimulation program can potentially be used to control fracture complexity and potentially result in a direct impact on stimulation effectiveness. The current study did not consider the type of failures associated with the activated fractures. Future studies will look into the role opening and closure of fractures play in stimulated fracture network effectiveness in fluid transport.



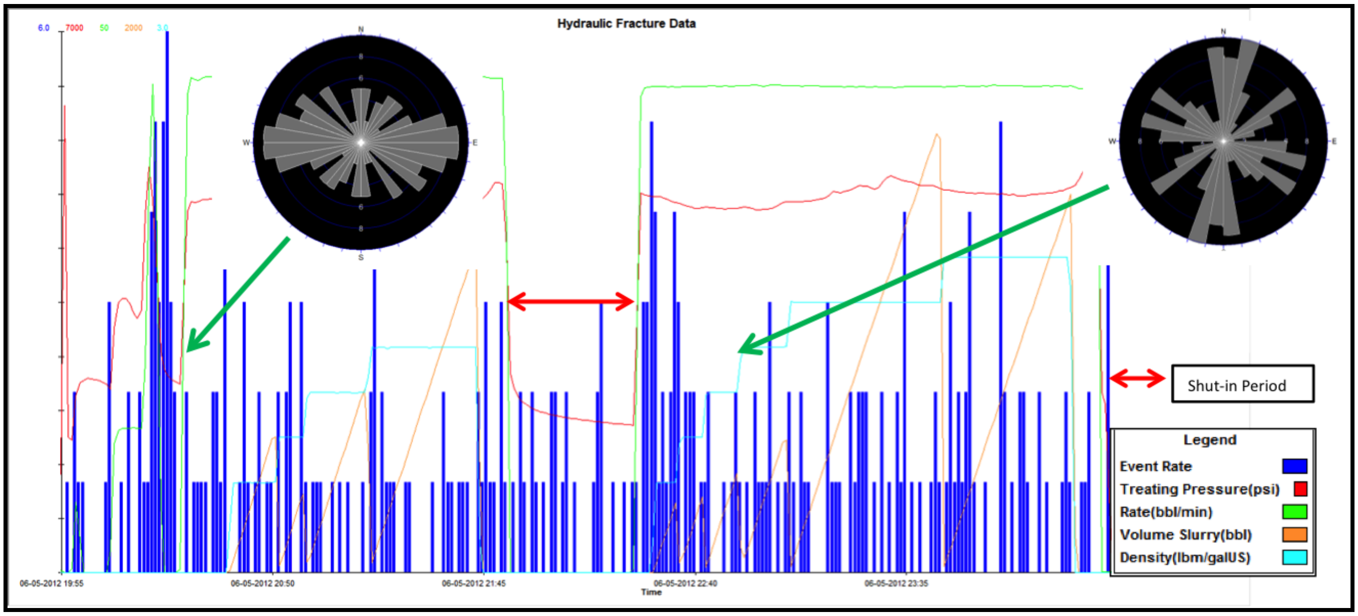


Figure 3. Top. Well 2, Stage C cyclic injection program (hesitation fracture) with a 24 hour shut-in (flow back) period. Bottom. Well 2, Stage E cyclic injection program (hesitation fracture) with a shortened shut-in (flow back) period.

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