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The Significance of Bedding Planes to Hydraulic Fracturing and Production

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Introduction

In unconventional plays it has long been suggested that traditional bi-wing models of fracturing may not be applicable in these highly fractured media. There is a persistent line of thinking that mesh models, such as proposed by Sibson (1997) and Hill (1977) or Pine and Batchelor (1984) based on geologic evidence, are appealing since the embedded features in them can be easily incorporated into a complex network model and may adequately describe the inter-play amongst pre-existing and newly generated vertical fractures. These models, however, do not sufficiently account for the presence of thinly bedded layers and the interaction of those bedding planes with the sub-vertical fracture sets or any indication as to what role these bedding plane fractures have in production. As Goldstein et al. (2011) showed, the activation of bedding planes during stimulations is an active part of the stimulation process and frac growth. Based on Seismic Moment tensor analysis they determined that a significant portion of events were generated as a result of slip related failure along horizontal planes, either associated with lithologic contacts or sub-laminar bedding within different geologic units under what can only be described as a dynamic stress field that locally perturbs the stress from known regional stress conditions. Baig et al. (2015) further supported the notion that local stresses are dynamic in response to injection and the driver for observed fracture complexity, showing that the principal stress axes flip-flop spatially during injections thereby allowing for the activation of a complex network of pre-existing fractures.

Here, we were presented with an often-observed dilemma that post-stimulation, treatment wells stimulated under similar injection conditions result in variable production, often inversely related to the number of events/activated fractures generated during the injection program. This is counter-intuitive as one would suspect that more events equal more active fractures which would suggest more free surface area is stimulated thereby leading to increased opportunities for production, assuming that similar in-situ volumes exist in both locations. This interpretation, however, lacks details on the types of failures being observed, fracture orientations, and relative fracture size (as related to the overall magnitudes of the individual events) that could provide insight into the observed behaviours. In this study, we attempt to identify how this unanticipated result may come about, and then raise questions as to whether traditional concepts of vertical fractures as related to hydraulic fracture stimulations need to be re-evaluated for unconventional shale reservoirs.

Investigation

To address this question we examine microseismic data collected from a North American shale gas play where multiple downhole geophone arrays were deployed to monitor the seismicity associated with multiple lateral treatment wells. Two horizontal wells (Figure 1), Well A and Well B, were stimulated with similar treatments and completion programs (same number of perforation clusters, but different lengths of treatment zones) and both targeted the same reservoir interval. For this study, we examined the 2 stages from each well that were closest to the geophone arrays and therefore did not have any detection biases over the range of magnitudes observed. The array configurations allowed for the calculation of event moment magnitudes, source dimensions (source radius) and therefore fracture length and area, energy and stress release, as well as moment tensor solutions and stress inversion that provided for fracture plane identification (azimuth and dip).

In Figure 2 the event distributions are shown for the two wells where Well A yielded more than twice as many microseismic events (M<0) as compared to Well B (1994 events versus 845 events, respectively). This would suggest that the stimulation program for Well A resulted in increased surface area and therefore would likely be the better producer of the wells, even though Well A exhibited greater height growth and extension out of the target formation. However, through moment tensor and source characterization analyses we gain a different perspective on the observed microseismicity. As shown in Figure 3, a significant portion of events in Well A are associated with failure of sub-vertical fractures. These fractures are in alignment with the J1 and J2 joint sets as identified by Engelder et al., 2009. Whereas, for Well B, a significant portion of the observed events are associated with sub-horizontal fractures and therefore are likely associated with bedding plane slip behaviour.

When we examine the production data for the two wells, interesting observations can be made. In essence there is increased production for Well B over time as compared to Well A. This suggests that the pathways back to the treatment well were well defined in Well A. However, over time, the interconnected behaviour in Well B allowed for drainage to continue over a longer time frame than for Well A thereby suggesting that the fluid is more efficiently percolating through these sub-horizontal bedding plane fractures and therefore enhancing the overall stimulation.

Summary

If we argue that the differences in well completion and treatment design are irrelevant as compared to the differences in observed fractures orientations and production results, it would suggest that bedding plane failures under different stress regimes play a critical role in production and further suggests that models and approaches based on sub-vertical or bi-wing fractures are insufficient to describe the processes associated with stimulations in shales. Although not conclusive, these observations do point to a need for developing discrete fracture models that include bedding planes and thereby a re-evaluation of the design criteria for stimulations. By designing stimulation programs to better control fracture orientations and ensuring a greater amount of surface area is being stimulated within the reservoir (by maximizing the amount of horizontal to sub-horizontal fractures), operators may have the potential to optimize production.

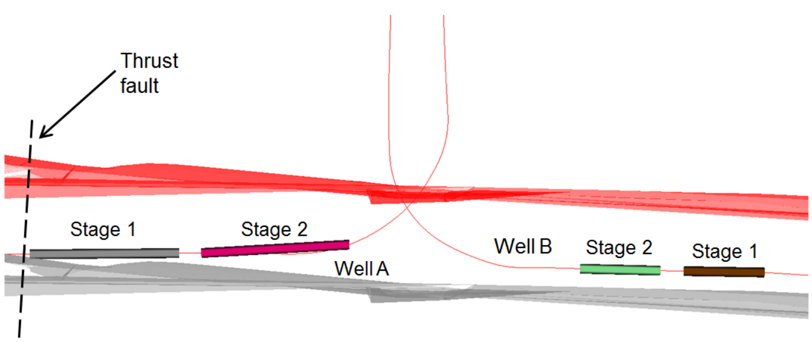

Figure 1: Well geometry of Well A and Well B.

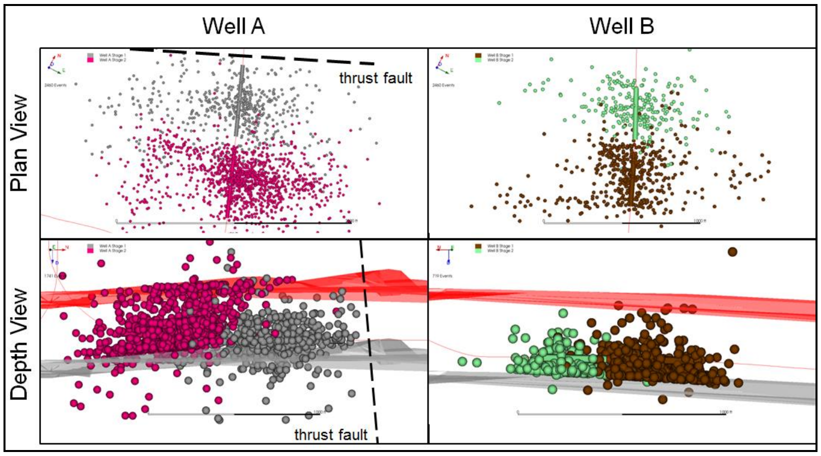

Figure 2: Event distributions s from Well A (left) and Well B (right).

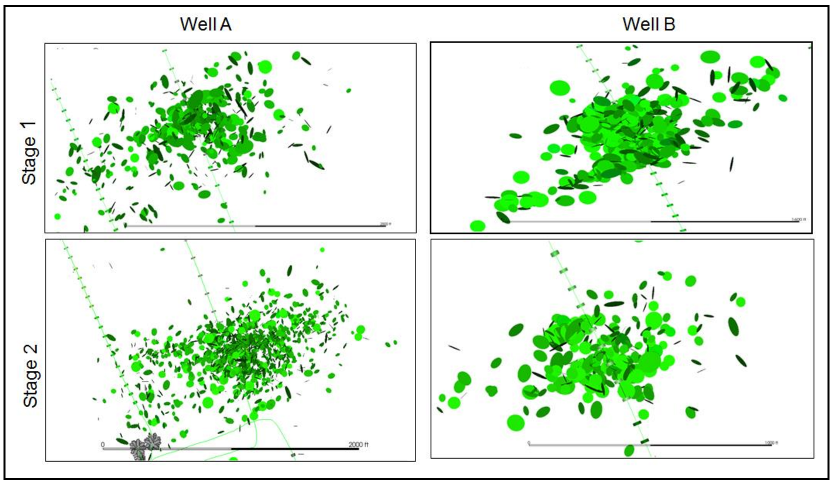

Figure 3: Fracture planes for both Well A (left) and Well B(right). Well B shows a predominance of sub-horizontal fractures, while Well A has more sub-vertical fractures.

	Initial Production (Mcf)	**# days**	**Longer Term Production (Mcf)**	**# days**
Well A	516134	70	931066	182
Well B	643705	72	1406359	182

Table 1: Published production data at day 70 and day 182 for Wells A and B.