The role of preexisting fractures and faults during multistage hydraulic fracturing in the Bakken Formation

Yi Yang¹ and Mark D. Zoback¹

Abstract

We performed an integrated study of multistage hydraulic fracture stimulation of two parallel horizontal wells in the Bakken Formation in the Williston Basin, North Dakota. There are three distinct parts of this study: development of a geomechanical model for the study area, interpretation of multiarray downhole recordings of microseismic events, and interpretation of hydraulic fracturing data in a geomechanical context. We estimated the current stress state to be characterized by an NF/SS regime, with $S_{H \max}$ oriented approximately N45°E. The microseismic events were recorded in six vertical observation wells during hydraulic fracturing of parallel wells X and Z with three unusual aspects. First, rather than occurring in proximity to the stages being pressurized, many of the events occurred along the length of well Y, a parallel well located between wells X and Z that had been in production for approximately 2.5 years at the time X and Z were stimulated. Second, relatively few fracturing stages were associated with an elongated cloud of events trending in the direction of $S_{H \max}$ as was commonly observed during hydraulic fracturing. Instead, the microseismic events in a few stages appeared to trend approximately N75°E, approximately 30° from the direction of $S_{H \text{ max}}$. Earthquake focal plane mechanisms confirmed slip on faults with this orientation. Finally, the microseismic events were clustered at two distinct depths: one near the depth of the well being pressurized in the Middle Bakken Formation and the other approximately 800 ft above in the Mission Canyon Formation. We proposed that steeply dipping N75°E striking faults with a combination of normal and strike-slip movement were being stimulated during hydraulic fracturing and provided conduits for pore pressure to be transmitted to the overlaying formations. We tested a simple geomechanical analysis to illustrate how this occurred in the context of the stress field, pore pressure, and depletion in the vicinity of well Y.

Introduction

The Mississippian-Devonian Bakken Formation is a restricted, shallow-water, mixed carbonate-clastic sequence deposited over most of the deep part of the Williston Basin (Gerhard et al., 1990). Using horizontal drilling and multistage hydraulic fracturing led to the successful development of the Elm Coulee (Montana) and Parshall (North Dakota) fields and demonstrated the great potential of the Bakken Formation. Despite the generally successful exploitation of the Bakken Formation, questions remain about how to optimize hydraulic fracturing and the importance of preexisting fractures and faults as fluid pathways in the reservoir.

The study area consists of three horizontal production wells (X, Y, and Z) and six vertical monitoring wells (A-F) (Figure 1). The three approximately 10,000-ftlong horizontal wells are located in the Middle Bakken. The well spacing is approximately 500 ft. Our study focuses on stimulation of wells X and Z. The middle well, well Y, had been hydraulically fractured previously and was in production for about 2.5 years prior to stimulation of wells X and Z.

Well-log data including gamma ray, electrical resistivity, density, and P- and S-wave sonic velocities are available from geophysical logs in vertical wells A, B, D, E, and F. Well logs from vertical well A are shown in Figure 2. The total thickness of the Bakken Formation is approximately 140 ft in the study area, with the top of the reservoir at a depth of approximately 10,000 ft. Wells X, Y, and Z were drilled in the Middle Bakken. As shown in Figure 2, the Upper, Middle, and Lower Bakken members can be easily distinguished from gamma-ray logs. The high gamma ray and high resistivity indicate the oil-saturated, organicrich shale layer in the Upper and Lower Bakken, and the low gamma ray and low resistivity in the Middle member is an indication of the target formation comprised principally of a dolomitic siltstone. The Upper and Lower Bakken shales are also characterized by lower density (approximately 2.3 g/cm^3) and lower

¹Stanford University, Department of Geophysics, Stanford, California, USA. E-mail: alecyang@stanford.edu; zoback@stanford.edu. Manuscript received by the Editor 7 October 2013; revised manuscript received 15 December 2013; published online 21 May 2014; corrected version published online 4 June 2014. This paper appears in *Interpretation*, Vol. 2, No. 3 (August 2014); p. SG25–SG39, 20 FIGS., 3 TABLES. http://dx.doi.org/10.1190/INT-2013-0158.1. © 2014 Society of Exploration Geophysicists and American Association of Petroleum Geologists. All rights reserved.

 $V_{\rm P}$ and $V_{\rm S}$ values, which can be attributed to lithology (clay- and organic-rich shale) and fluid-saturation differences.

In the sections below, we first report the development of a geomechanical model that includes knowledge of the magnitude and orientation of principal stresses, the existence and orientation of natural fractures and faults, and the mechanical properties of the formations being produced. Knowledge of the stress field can be used to better understand microseismic events and fracture networks resulting from hydraulic fracture stimulation (Fehler et al., 1987; Phillips et al., 1998; Rutledge et al., 1998; Maxwell et al., 2002). Therefore, linking observations of microseismic data with geologic and geophysical information can help us better understand the geomechanical properties of the



Figure 1. Entire microseismic events and the well geometry in this study, including three horizontal wells (X, Y, and Z), and six vertical observation wells (A-F). Events are colored by stages. (a) Map view with the arrows represents stimulation sequence along wells X and Z, (b) north–south cross view with geologic formations and geophone locations along each vertical observation well, and (c) histogram of number of events for each stage.



Figure 2. Petrophysical log collected from well A showing the lithologic profile across the Bakken Formation.

Bakken Formation and the role of preexisting fractures and faults on the effectiveness of hydraulic fracturing stimulation in this reservoir.

Geomechanics of the study area

To build a quantitative geomechanical model, we follow the general procedure outlined in Zoback (2007) to constrain the orientation and magnitudes of the three principal stresses in the reservoir. The magnitude of vertical principal stress was determined from the weight of the overburden, whereas estimates of pore pressure (P_p) were available from diagnostic fracture injection test (DFIT) data, which provide instantaneous shut-in pressure (ISIP) to constrain the magnitude of $S_{h\min}$. Physical properties were determined by commercial laboratory tests on Bakken core samples from well

A. The values are listed in Table 1.

Unfortunately, there are no image logs at this site to determine the orientation of the maximum compressive stress from the orientation of compressive and/or drilling-induced tensile wellbore failures. Previous studies close to the study area report the orientation of $S_{H \max}$ to be approximately N45-55° E, based on the DITFs observed in Formation MicroImager (FMI) logs obtained from three horizontal wells (Olsen et al., 2009; Sturm and Gomez, 2009). Using the physical property measurements from the core samples, as well as estimates of S_V , $S_{h\min}$, and P_p from this study, we used the methodology outlined in Peška and Zoback (1995) to analyze the occurrence of tensile fractures in the wells studied by Sturm and Gomez (2009) as a function of $S_{H \max}$ orientation and magnitude (see Appendix A). This modeling indicates that when $S_{H \max}$ is oriented toward N45-55°E, transverse tensile fractures that are quite similar to those reported by Sturm and Gomez (2009) will occur. However, the magnitude of $S_{H \max}$ is not well constrained by the modeling. The stress state could either be a normal faulting or a strike-slip faulting regime.

Microseismic events during hydraulic stimulation

As shown in Figure 1, microseismic events during hydraulic fracturing of wells X and Z were monitored with approximately 1900-ft-long, 40-level, 3C geophone arrays in six vertical observation wells (A-F). The spacing between seismometers in each array was 49.2 ft. Hydraulic fracturing was first performed along well X from toe to heel and consisted of 29 stages, followed by another 38 stages along well Z. For both wells, different hydraulic fracturing methods were used along the lengths of the wells: Stages 1–18 (well X) and stages 31–49 (well Z) used a ball-activated sliding sleeve with swell-packers; stages 19–29 (well X) and stages 50–67 (well Z) used pumpdown perforation guns with bridge plugs. Both stimulations used a hybrid fluid system (slickwater, linear gel, and crosslinked gel), sand, and ceramic proppants. The cumulative fluid volumes injected during stimulation in wells X and Z were approximately 72 and 84 Mbbls, respectively. Note that the middle well Y was hydraulic fractured approximately 2.5 years prior to the fracturing along wells X and Z in this study; however, it was not microseismically monitored at the time of fracturing.

A total of 6499 treatment-induced microseismic events were detected and located by the contractor (Figure 1a and 1b). Event histograms of each stage (Figure 1c) show that the number of events in several stages (i.e., stages 2–4, stages 50–53) is much higher than in other stages. Events from six selected stages (i.e., stages 2–5, 43, and 50) were reprocessed by a second contractor. Both initial and reprocessed hypocenter locations show unusual characteristics.

Events along wellbore Y

The first unusual observation of the microseismicity is that many of the events occur along well Y during pressurization of stages in wells X and Z. Figure 3 demonstrates the spatial-temporal evolution of events in stage 4. A few events occurred near the perforation location in well X as expected at the beginning of

injection; however, after approximately 20 min, the great majority of events occurred along the length of well Y, thousands of feet away from the perforation location near the toe of well X.

The pressure records of wells X and Y during stage 4 show that the occurrence of microseismic events along well Y was associated with increased pressure in well Y starting about 20 min after pressurization of well X (Figure 3d). In the beginning of stage 4 when the events clustered close to the perforation location, the pressure in well Y remained constant at approximately 2213 psi downhole pressure. When many events began to occur thousands of feet southward along well Y, the fluid pressure began to rapidly increase in well Y. The sudden increase in pressure in well Y indicates that fluid pressure from pressurization of well X was being observed in well Y, presumably via fluid pathways through preexisting fractures and faults. Dohmen et al. (2013) argued that the microseismic events along well Y are distributed throughout the depletion zone

surrounding this original production well. As explained below, our analysis suggests that microseismic events along well Y do not necessarily depend on prior depletion. In other words, it does not matter if the reservoir was at initial or depleted conditions, these microseismic events would occur during hydraulic fracturing as long as there are preexisting fracture and faults in the area.

Events cluster at multiple depths

As illustrated in Figure 1, another unusual observation is that the microseismic events occur at two distinct depths: one clustered within or near the Middle

Table 1. List of parameters values of geomechanical properties and sources at Middle Bakken.

Parameters	Values at Middle Bakken	Source
S_v gradient	1.05 psi/ft	Integration of density log
$S_{h\min}$ gradient	0.79 – 0.85 psi/ft	DFIT data
P_p gradient	0.66 – 0.7 psi/ft	DFIT data
Young's modulus	3.77 * 10 ⁶ psi	Rock mechanics test
Poisson's ratio	0.21-0.31	Rock mechanics test
UCS	16 * 10 ³ psi	Rock mechanics test
Internal	0.8	Rock mechanics test
friction Sliding friction	0.6	Common estimate



Figure 3. (a) Chronicle progression of microseismic events and corresponding pressure recording of stage 4 during well X stimulation. The triangle symbols represent perforation location. (a) Map view of microseismic events, (b) north–south cross view of microseismic events, (c) colormap of events chronicle distribution in (a) and (b), and (d) injection pressure of X (red line) and downhole pressure record of Y (black line) of stage 4.

Bakken Formation and the other clustered at a much shallower depth approximately 800 ft above the well depth in the Mission Canyon (MC) Formation. In fact, there are more microseismic events located in the MC Formation than in the Bakken. Figure 4 shows that the stages associated with the largest number of events are the stages with many events in the MC Formation. In particular, see stages 2, 3, and 5 near the toe of well



Figure 4. Relative depth (with respect to the Bakken Formation) histograms of microseismic events by stages for wells X and Z, as well as the corresponding average surface treatment pressure of each stage.



Figure 5. Waveforms of a large event located at MC in stage 50, recorded by 3C (H₁, H₂, and Z) geophones in array B. The array ranges from approximately 8000 to 9960 ft, and the bottom of the array is approximately 50 ft above the top of the Upper Bakken Formation.

X and stages 50–52 near the middle of well Z. Moreover, whereas the events in the MC Formation occurred in just a few stages of well X (stages 2–5 and stage 18), events in the MC Formation are associated with more than half of the stages of well Z.

Interestingly, the average surface treatment pressure during the stages associated with large number of shallow events does not seem to be different from the pres-

> sure in other stages. For example, stages with a larger number of microseismic events in the MC Formation are not associated with higher treatment pressures (with exception of stage 18), whereas two stages with relatively high treatment pressure (i.e., stages 17 and 47) are associated with very few events. We investigated the correlation of microseismic data with other variables such as the maximum/average treatment pressure and the volume of fluid and proppant injected, and no correlation was found. Hence, these shallow events seem to be more likely the result of a vertical hydraulic connection associated with preexisting fractures and faults rather than anomalous hydraulic fracturing procedures.

> Figure 5 illustrates a selected shallow event from stage 50 recorded by 3C geophones in well B. The three components of each geophone within the entire array are plotted together, where the bottom of the array is approximately 50 ft above the top of the Bakken Formation. Clear P- and S-wave arrivals are observed with simple moveout. The waves arrival times clearly indicate that the event is located in the MC Formation. The minimum P-wave arrival time is observed

approximately 800 ft above the well depth.

Events trend approximately 30° with respect to $S_{H \max}$

During hydraulic fracture stimulation, one expects Mode I (opening mode) hydraulic fractures to open in a plane perpendicular to the least principal compressive stress, or equivalently, parallel to the direction of $S_{H \max}$ in a strike-slip or normal faulting environment. As the microseismic events are associated with slip on preexisting faults surrounding the hydraulic fractures when the well is being pressurized, the microseismic events are generally expected to form an elongated cloud extending in the $S_{H \max}$ direction from the perforations (e.g., Maxwell et al., 2002; Fisher et al., 2004; Moos et al., 2011). As described below, the great majority of events located in this study are not consistent with this pattern. Instead of trending approximately N50°E in the direction of $S_{H \max}$ as expected, the dominant trend of hypocenters is approximately 30° from $S_{H \max}$. A total

of approximately 1500 microseismic events from stages 50 to 52 are shown in Figure 6 and illustrate a consistent trend approximately 30° from the $S_{H \max}$ direction (the blue solid line). This approximately 30° offset with respect to $S_{H \max}$ indicates that these microseismic events

are probably occurring along a preexisting natural fault at the orientation expected for strike-slip faults. Therefore, it suggests that well-oriented, preexisting strike-slip faults exist in the area, and the fluid injection during hydraulic stimulation of stages 50–52 activated slip on the faults and caused the approximately 1500 microseismic events.

To constrain the source mechanism of these microseismic events, we constructed earthquake focal plane mechanisms for selected microseismic events in stage 50 by using the first motion of P-wave observed on the borehole geophones (Aki and Richards, 2002). To construct the focal plane mechanisms, the waves were assumed to propagate along a linear path between the source and the receiver. Because the distance between the microseismic hypocenters and geophones is very small (<2000 ft) and the P-wave velocity between the hypocenters and seismometers is nearly constant (Figure 2), this assumption is quite reasonable. Second, for the shallow events, the events and geophones are located within a relatively homogeneous limestone formation. The simplicity of the waveforms shown in Figure 5 indicates the simple path between the source and receiver and the lack of converted phases.

The 3C seismograms are rotated from the geographical coordinates (H_1, H_2, H_2) and Z) to radial and transverse directions. Because the two horizontal components $(H_1 \text{ and } H_2)$ are rotated in the horizontal plane, it requires additional controlled source to calibrate geophone rotations. Because the horizontal orientation of the geophones is not available for this analysis, instead of orienting the vertical and one horizontal component in the same plane with the wave propagation direction, we directly rotate the vertical component (Z) to the wave propagation direction (Figure 7a). Therefore, only direct P-wave arrival can be used for construction of the focal plane mechanisms. After rotation, the direct P-waves would propagate in the direction from the source to the receiver with the first motion up for compression

and down for dilation. Figure 7b and 7c illustrates an example of seismogram recordings before and after rotation.

To find the best-fitting focal planes with the limited receiver azimuth coverage, we use the P-wave radiation



Figure 6. The distribution of 1497 microseismic events of stages 50–52 during *Z* stimulation. (a) Map view of the microseismic events, the fitted orientation of a potential fault (red solid line), the current N50°E $S_{H \text{ max}}$ orientation (blue arrow line), and the orientation of theoretical conjugate fault (red dashed line), (b) zoom in view of north–south cross section of the microseismic events, and (c) idealized relationship between conjugate sets of strike-slip fault and principal stresses (map view).



Figure 7. (a) Schematic illustration of seismogram rotation, (b) seismogram recorded by a 3C geophone before rotation, and (c) seismogram of the 3C geophone after rotation.



Figure 8. Radiation pattern of P-wave first motions for the selected event and corresponding beach-ball solutions using recording from arrays A, B, D, and F. (a) Predicted P-wave first motions of a certain focal mechanism and corresponding beach ball and (b) observed P-wave first motions and best-fit focal plane solutions.



Figure 9. Contour map of misfit between predicted and observed P-wave first motions for various dip and rake.

pattern in the homogeneous far-field to predict the polarization (Aki and Richards, 2002) and compare the predicted results with the observations. Because the microseismic events of stages 50-52 follow a consistent trend of N75°E, we assume this is the orientation of the slipping fault and then predict the P-wave first motions by varying dip and rake values. Figure 8 shows an example of the predicted P-wave first motions with strike/dip/rake as $75^{\circ}/65^{\circ}/$ -74° (a) and the observed P-wave first motions (b), based on the same source and receiver locations for a selected microseismic event. Although there are some minor inconsistencies between the observation and prediction, the overall fit is quite good. We define the misfit as the percentage of the number of inconsistency over the total number of observed polarizations and apply a grid search methodology to calculate the minimum misfit as a function of dip and rake. Figure 9 shows a contour map of misfit for varying dip and rake for a fault striking N75°E. It is clearly seen that although there is no unique solution due to the limited geophone coverage, there are multiple solutions that can equally fit the observation within a limited range of rake and dip values (Figure 8b). Clearly, the radiated seismic wavefield implies a steeply dipping fault (> 65°), with high rake values

 $(-70^{\circ} \text{ to } -90^{\circ})$, suggesting normal faulting with a small strike-slip component.

Figure 10 shows six events with hypocenters spatially spread out along the interpreted fault in Figure 6. Note that the selected six events occur in the MC Formation during pressurization of stage 50. These events have a high signal-to-noise ratio, and the signals are well recorded by most of the geophones along arrays A, B, D, and F. The distribution of focal mechanisms (Figure 10c) also suggests the existence of approximately N75°E trend fault plane in the area. Dip angles are between 65° and 88°. The slip on the N75°E steeply dipping plane in these events is normal and strike-slip, which indicates magnitudes for three principal stresses of $S_v \sim S_{H \max} > S_{h \min}$.

To compare and contrast the microseismic events occurring in the Bakken and MC, Figure 11 shows the locations of the events only during stage 50. It can be clearly seen that the events from the Bakken and MC follow a similar N75°E trend. The limited P-wave polarization of an event from the Bakken Formation (Figure 11c) which is consistent with focal mechanism of events from the MC Formation, suggests that the events at both depths have the similar source mechanism. This suggests that the steeply dipping fault, determined from focal plane solutions on MC events, appears to connect the deep Bakken Formation and serves as fluid conduit during hydraulic stimulation in stage 50 and causes the events in the MC Formation. Therefore, a steeply dipping, approximately N75°Etrending fault appears to connect the Bakken and MC Formations previous a fluid with

MC Formations, providing a fluid pathway during hydraulic fracturing in the Bakken Formation. An Ant TrackTM image of 3D seismic in the study area suggests faults at the depth of MC with a similar trend (M. Simon, personal communication, 2013).

Events near the toe of well X

Events from stages 2-5 near the toe of well X were reprocessed by a second contractor (Figure 12). Although in general, the reprocessed event locations captured the characteristics we observed in Figure 1 (see Appendix B), there are some differences worth noting. First, the reprocessed events at the toe of well X (i.e., stage 2) now show a strong lineation in the direction of N75°E that is consistent with what we have observed in stages 50–52 (Figure 6). Second, many reprocessed events are located in the Lodgepole Formation, displaying a connection between the Bakken and MC. Originally, few events were located at this depth. Altogether, the reprocessed events seem to outline a steeply dipping plane connecting the MC and Bakken Formations, similar to the fault conduit we interpreted for stages 50–52. Interestingly, as the hydraulic fracturing was proceeding from stages 2-5, the hypocenters occur progressively downward from the MC to the Bakken (Figure 12).

Spatial-temporal plots of these events, including depth and horizontal position versus time, are shown in Figure 13 to examine the temporal growth of the microseismic clouds associated with stages 2-5. The downward progression of the events in these four stages is fairly continuous although there is a clustering of events at specific depths during each stage (Figure 13b). The horizontal positions of the events along the N75°E trend are plotted with respect to injection location of stage 2 (zero along the y-axis in Figure 13c). The stages show different characteristics of growth along the N75°E trend. Microseismic events in stages 2, 4, and 5 are

principally to the southwest of the well (especially stage 2), whereas events in stage 3 are concentrated nearly directly above the well. The strong N75°E lineation of hypocenters seen in stage 2 appears to be associated with slip along a prominent fault. Events from stages 4 and 5 appear to be caused by slip along many smaller fractures clustered closer to the well, above in the



Figure 10. (a) Map view of selected events for focal mechanism analysis for stage 50, (b) cross view of selected events, and (c) focal plane solutions of six selected events.



Figure 11. (a and b) Map view and cross view of events from the Bakken Formation and MC Formation during stage 50 and (c) P-wave polarization of an event from the Bakken Formation.

Lodgepole Formation and below in the Three Forks Formation (Figure 12c).

A striking observation of the pumping history during stage 5 (Figure 13a) further supports the argument that hydraulic stimulation is inducing microseismicity by channeling flow through a network of preexisting faults. During stage 5, the fluid injection was shut down after approximately 20 min due to the broken blender at the surface, with the pressure dropping from 4100 to 2800 psi (Figure 13a). Because the pressure after the pause of injection was far below the fracture gradient, the distribution of microseismic events in stage 5 was triggered by relatively low pressure in preexisting network of fractures and faults without the presence of a large hydraulic fracture. Recall that during stages 4 and 5, microseismic events were also seen thousands of feet southward along well Y (Figure 3). Thus, the spatial distribution of events and the occurrence of events during stage 5 at pressures lower than the fracture gradient support the hypothesis of fluid channeling along faults near well X and length of well Y during stage 4 stimulation.

Fault slip analysis

The hypocenter distributions of microseismic events and the focal mechanisms suggest the existence of



Figure 12. Reprocessed events locations at stages 2-5 near the toe of well X. (a) Map view of the events, (b) cross view of the events, and (c) 3D view (looking to the direction of S75°W).

steeply dipping faults in the area that connect the deep Bakken Formation with the shallower MC Formation. To test whether the pore pressure perturbation during hydraulic fracture stimulation at the Bakken Formation is likely to cause the slip on the faults in the local stress field, we assess the proximity of each nodal plane in the focal mechanisms shown in Figure 10 to evaluate the potential for shear failure in the local stress field in the context of the Mohr-Coulomb failure criterion. We use a stress field in which $S_v \sim S_{H \max} > S_{h \min}$ in the model because the focal plane mechanisms indicate normal faulting with a small component of strikeslip faulting. We use geomechanical properties such as Poisson's ratio and the Biot coefficient of the Middle Bakken (Table 2) because they were measured directly from core samples collected from well A and were not available for the MC Formation.

We test two scenarios with different stress paths. First, fluid is injected into the reservoir in its initial state, ignoring any depletion effects from production in well Y (Figure 14a and 14b). The second scenario attempts to account for the depletion effects on the stress field prior to hydraulic fracturing of wells X and Z. The stress path associated with this scenario is based on approximately 4450 psi depletion in well Y as illustrated by the pressure data shown in Figure 3 (Figure 14c

> and 14d). We assume that the fault plane orientations shown in Figure 8 are representative of the study area and plot them in the stereonets and Mohr circles. The background color of the stereonets represents the excess pressure needed to cause slip for a coefficient of friction of 0.6 for poles of the fault planes. The Mohr circles illustrate the effective shear and normal stresses on the planes for the various cases considered.

> For the first scenario without depletion, the initial reservoir pressure in the Middle Bakken is approximately 6700 psi. Note that for the estimated initial stress field and pore pressure, neither the steeply dipping, N75°E fault, or its auxiliary plane would be expected to slip prior to stimulation (Figure 14a). During hydraulic fracturing, a pore pressure perturbation of only approximately 330 psi would be sufficient to cause the well-orientated N75°E fault to slip (Figure 14b). Because the average pumping pressure during hydraulic fracturing is approximately 1300 psi above the initial reservoir pressure, approximately 330 psi pore pressure increase could be easily achieved during stimulation.

> For the second scenario, the reservoir is depleted prior to the stimulation due to the previous production in well

Y. With approximately 4450 psi depletion from the initial reservoir state, the Mohr circle moves to the right with increasing circle size, due to the relative increase in the vertical effective stress with respect to the horizontal effective stresses (Figure 14c). The stress state after depletion indicates that slip is not expected on the approximately N75°E-trending fault. As shown in

Figure 14d, a pore pressure increase of approximately 1600 psi is required to induce slip on approximately N75°Etrending faults. As the reservoir pressure is only approximately 2200 psi after depletion, an increase in pore pressure of approximately 1600 psi could also be easily achieved during hydraulic fracturing because the pumping pressure is close to 8000 psi. As discussed in Appendix C, Dohmen et al. (2013) carry out a similar analysis for the zone of depletion around well Y and estimated that a pore pressure perturbation approximately 1200 psi was required to induce shear failure. Details of our respective analyses, including the sensitivity of the results to physical properties (i.e., Biot coefficient, Poisson's ratio), are discussed in Appendix C.

Figure 15 summarizes our interpretation of events at stages 2–5 and 50–52. We propose that relatively large and small preexisting fractures and faults are present in the vicinity of wells X, Y, and Z and significantly affect the hydraulic fracture stimulation. Relatively large scale faults serve as fluid pressure conduits and transmit injected fluid to other formations, resulting in the outof-zone seismicity. Small fractures also transmit injected fluid from well X to well Y and cause the microseismic events along the length of well Y.

Conclusions

In this study, we integrated geomechanics with microseismic data to understand the role of natural fractures and faults during multistage hydraulic fracturing stimulation in the Middle Bakken Formation. Analysis of the microseismic locations, focal plane mechanisms, and fault modeling points to the importance of preexisting faults as conduits for pressure and fluid transmission during hydraulic fracturing. In several locations, the existence of relatively large-scale, steeply dipping faults in the area transmit pressure and fluid from the Bakken Formation upward to the MC. Slip would not be expected

on these preexisting faults without the perturbation during multistage hydraulic fracturing. Overall, we attribute the spatial pattern of hypocenters to be controlled by the distribution of preexisting fractures and faults. We believe that the unusual microseismic patterns observed in this study result from fluid channeling dominated by preexisting fractures and faults,



Figure 13. Spatial temporal relations of microseismic events at stages 2–5. (a) Injection records of stages 2–5, (b) events locations along vertical direction with respect to the depth of the Middle Bakken, (c) events positions along the N75°W trend with respect to the perforation location of stage 2, and (d) histogram of event numbers.

Table 2. Inputs for Mohr circle analysis with different stress paths.

	(a)	(0)	(C)	(0)	
S_v (psi)	10,605	10,605	10,605	10,605	
$S_{H \max}$ (psi)	10,302	10,302	7819.3	7819.3	
$S_{h\min}$ (psi)	8080	8080	5597.3	5597.3	
P_p (psi)	6666	6996	2213	3813	
ΔP (psi)	0	330	-4453	1600	
Biot coefficient (α)	0.8	0.8	0.8	0.8	
Poisson's ratio	0.25	0.25	0.25	0.25	
Friction coefficient (μ)	0.6	0.6	0.6	0.6	
$S_{H \max}$ azimuth	N50°E				
Strike	N75°E				
Dip angle/dip direction	69°/N165°E				



Figure 14. Stability analysis of the fault planes in the Middle Bakken. (a) A prestimulation scenario with no pressure perturbation, (b) a poststimulation scenario from initial state with pressure perturbation of 330 psi, (c) a depleted scenario with pore pressure depletion of 4453 psi, and (d) a poststimulation scenario from depleted state with pressure perturbation of 1600 psi. The background color of the stereonets is the pore pressure elevation necessary to initiate slip for a coefficient of friction of 0.6. The white circle is the pole of the activated fault, and the black tadpole is the slip motion of the activated plane. Mohr circles include the representative fracture/fault and its auxiliary plane. The activated planes in response to pore pressure elevation are shown in red in the Mohr circle.



Figure 15. Schematic model to demonstrate the effects of preexisting fractures and faults during hydraulic fracture stimulation at stages 2–5 and 50–52.

and that the depletion near well Y promoted the fluid pressure transmission process from wells X and Z toward well Y during hydraulic fracture stimulation.

Acknowledgments

We thank the Hess Corporation for providing the data to carry out the research and permission to publish this study. We thank B. Hughes for providing software used in geomechanical analysis. We also thank T. Dohmen and M. Simon for the valuable discussions. Financial support was provided by Stanford Rock Physics and Borehole Geophysics (SRB) Industrial Consortium and Hess Corporation.

Appendix A

The S_{HMAX} orientation and magnitude

FMI image logs provide a continuous unwrapped image of the borehole wall and include information about the distribution of natural fractures, as well as the distribution of wellbore failures, such as breakouts and drilling-induced tensile fractures (DITFs). Borehole breakouts are compressive failures on the walls of the borehole that occur when the maximum resolved compression exceeds the rock failure strength. DITFs are tensile failures on the wellbore wall that occur when the minimum resolved effective stress becomes negative and the wall fails in tension. The effective stresses at the well face of a vertical wellbore in a linear isotropic

elastic medium are described by the Kirsch equations:

$$\begin{aligned} \sigma_{\theta\theta} &= S_{H\max} + S_{h\min} - 2(S_{H\max} + S_{h\min})\cos 2\theta - 2P_p \\ &- \Delta P - \sigma^{\Delta T}, \end{aligned} \tag{A-1}$$

$$\sigma_{zz} = S_V - 2(S_{H\max} - S_{h\min})\cos 2\theta - P_p - \sigma^{\Delta T}, \quad (A-2)$$

and

0

$$\sigma_{rr} = \Delta P, \qquad (A-3)$$

where ΔP is the difference between the pore pressure and the mudweight, $\sigma^{\Delta T}$ is the thermal stress from the temperature contrast between the reservoir and the drilling fluids, and $\theta = 0$ is the direction of $S_{H \max}$ (Zoback et al., 2003).

However, when the borehole axis is not aligned with one of the principal stress axes, the direction of maximum tension becomes oblique relative to the borehole axis, resulting in an inclined DITF (Figure A-1). To calculate the stress concentration around the borehole, we need to transform the principal stresses (i.e., S_1 , S_2 , S_3) into borehole Cartesian coordinates, and this is described in detail by Peška and Zoback (1995). After coordinate transformation and adding the effect of P_p to obtain effective stress, the perturbed stress field around a misaligned borehole at the borehole wall is given by Hiramatsu and Oka (1966),

$$\sigma_{zz} = \sigma_{33} - 2v(\sigma_{11} - \sigma_{22})\cos 2\theta - 2v\sigma_{12}\sin 2\theta, \quad (A-4)$$

$$\begin{split} \sigma_{\theta\theta} &= \sigma_{11} + \sigma_{22} - 2(\sigma_{11} - \sigma_{22})\cos 2\theta - 4\sigma_{12}\sin 2\theta \\ &- P_m + P_p, \end{split} \tag{A-5}$$

and

$$\tau_{\theta z} = 2(\sigma_{23} \cos \theta - \sigma_{13} \sin \theta), \qquad (A-6)$$

where θ is the angle around the borehole wall in the cylindrical coordinate system and ν is the static Poisson's ratio of the medium. Considering the principal stresses at the borehole wall, the magnitude and orientation of the tangential stress become (Peška and Zoback, 1995):

$$\sigma_{t \max}(\theta) = \frac{1}{2} (\sigma_{zz} + \sigma_{\theta\theta} + \sqrt{(\sigma_{zz} - \sigma_{\theta\theta})^2 + 4\tau_{\theta z}^2}), \quad (A-7)$$

$$\sigma_{t\min}(\theta) = \frac{1}{2}(\sigma_{zz} + \sigma_{\theta\theta} - \sqrt{(\sigma_{zz} - \sigma_{\theta\theta})^2 + 4\tau_{\theta z}^2}), \quad (A-8)$$

and

$$\omega(\theta) = \frac{1}{2} \arctan\left(\frac{2\tau_{\theta z}}{\sigma_{zz} - \sigma_{\theta\theta}}\right), \quad (A-9)$$

where ω is the inclination of the maximum tangential principal stress from the borehole axis, which determines the inclination of the DITFs relative to the borehole axis. DITFs will occur around the wellbore where the most tensional stress becomes negative, assuming the tensile strength of a rock is essentially zero.

In our study, we first analyze the three FMI logs obtained from three horizontal wells described by Sturm and Gomez (2009) that are close to our study area. Although the quality of the FMI logs are low quality, we are able to find that DITFs occur at a few depth ranges at the top and bottom of the wellbore and that most of them intersect the wellbore axis with a high angle (transverse). Figure A-2a displays an example of DITFs with high inclination angle (approximately $50^{\circ}-60^{\circ}$) located at the bottom of the wellbore. We then use the physical property measurements from the core samples, as well as estimates of S_v , $S_{h\min}$, and P_p to model the DITFs occurrence along this east-westtrending horizontal well. Modeling is performed using BSFO module of the software SFIB by GeoMechanics International. An example of matching results is shown in Figure A-2b, with an $S_{H \max}$ orientation of N50°E and magnitude of 1.02 psi/ft. Although the DITFs modeled match the observation with a high inclination angle at the top and bottom of the wellbore, the inputs for $S_{H \max}$ orientation and magnitude are not unique because many other combinations will also predict similar DITFs. Therefore, we follow the methodology outlined by Peška and Zoback (1995) and predict the position and inclination angle of DITFs, with a wide range values



Figure A-1. Schematics of occurrence of DITFs in an image log when borehole axis is not aligned with principal stress (modified from Zoback, 2007).



Figure A-2. Observed and predicted DITFs along an eastwest-oriented horizontal wellbore. (a) DITFs occur at top and bottom of the wellbore with high inclination angle, an example from FMI logs of well Nesson State 44X-36H that were reported by Sturm and Gomez (2009) and (b) predicted DITFs with inputs listed in Table 1 and $S_{H \text{ max}}$ oriented N50°E with a magnitude of 1.02 psi/ft.

of $S_{H \max}$ orientation and magnitude. Figure A-3 combines many information including presence/absence of DITFs (color versus white), the inclination angle (ω) of DITFs with respect to the borehole axis (color map), and their position around the borehole. It is clearly seen that when the magnitude of $S_{H \max}$ is enormously high (i.e., upper left corner of the plot), trans-



Figure A-3. Predicted occurrence of DITFs with varying combinations of $S_{H \max}$ orientations and magnitudes, colored by inclination angle ω to the wellbore axis; the higher ω (hot color) represents transverse DITFs, and the lower ω (cool color) represents axial DITFs.



Figure B-1. Initial and reprocessed microseismic event locations at stages 2–5, 43, and 50. (a and b) Map view of reprocessed and initial locations', (c and d) north–south cross view of reprocessed and initial locations.

verse DITFs will be predicted with $S_{H \max}$ oriented between N0° and 40°E, but they will occur near the side of the wellbore instead of top and bottom. To be consistent with the observation, with approximately 50°–60° inclined fractures at the top and bottom of the wellbore, $S_{H \max}$ should orient approximately N45°–55°E as reported by Sturm and Gomez (2009). However, the magnitude of $S_{H \max}$ cannot be further constrained, and stress state suggests either a normal faulting or a strike-slip faulting regime.

Appendix B

Microseismic events uncertainties

The microseismic events shown in this study (except for events in Figures 12 and 13) were initially monitored and processed by the first contractor, and they determined the microseismic event location by using P-wave arrival times (i.e., moveout) at the geophones and converted them to source location using a Kirchhoff diffraction migration and stacking method in a 3D grid. The 3D-velocity model applied was upgraded from wellbore sonic log data using the seismic signals from the perforation shot events, which accounts for horizontal and vertical anisotropy. Perforation calibration of the 84 known perforation locations showed an averaged location error approximately 69 ft, which corresponds to the average location error of the microseismic events. The second contractor reprocessed six selected stages (stages 2-5, 43, and 50) and used P- and S-pick times and the 3C hodogram information plus forward modeling on a grid-search-based velocity model to arrive at a location that has low residual time error.

> Figure B-1 compares the initial and reprocessed event locations for the reprocessed stages. Obviously, the reprocessed event locations also exhibit the unique patterns similar to what we observed on initial locations. For example, the events in stage 50 follow the N75°E trend, and many events in stage 4 distribute thousands of feet southward along the middle well. Moreover, events are located at the Bakken Formation and MC Formation. The consistency between the initial and reprocessed locations suggests that these microseismic event locations were credible, and the observed event patterns indeed reflected the reservoir responses during hydraulic fracture stimulation.

Appendix C

Fault slip analysis of events along well Y

As mentioned above, prior to hydraulic fracturing of wells X and Z, the middle well Y has been in production for approximately 2.5 years. Therefore, the reservoir adjacent to well Y was depleted and the local stress field was affected. The change of horizontal stress magnitude resulting from depletion is estimated by poreoelastic theory and described by

$$\Delta S_{\text{Hor}} = \alpha \frac{(1-2\nu)}{(1-\nu)} \Delta P_p \tag{C-1}$$

(Engelder and Fischer, 1994). The α is the Biot coefficient and ν is the Poisson's ratio.

While the Mohr circles shown in Figure 14 correspond to the input values from Table 2, it is obvious that the depletion effects on the horizontal stress are controlled by the Biot coefficient and Poisson's ratio (see equation C-1). Laboratory measurements of six core samples obtained from the Middle Bakken in well A show that the Poisson's ratio ν ranges from 0.21 to 0.31. The Biot coefficient α is defined by

$$\alpha = 1 - \frac{K_b}{K_g} \tag{C-2}$$

(Nur and Byerlee, 1971), where K_b is drained bulk modulus of the rock and K_g is the bulk modulus of the rock's individual solid grains. We measured the volumetric strain of the two core samples at the hydrostatic condition, using the core samples from the Middle Bakken in well A. Our results suggested

that K_b ranges from 7.85 to 9.53 GPa when the confining pressure changes from 20 to 30 MPa. The mineralogy of the sample measured by XRD is listed in Table C-1. Using the Hill's average (Mavko et al., 2009) of 18.5% clay, 52.5% calcium, and 29% quartz, K_g is approximately 41.15 GPa. Therefore, α in the Middle Bakken ranges from 0.78 to 0.81.

Figure C-1 shows the dependence of specific parameters in the fault slip analysis. With a coefficient of friction of 0.6 and 4453 psi depletion, Figure C-1a illustrates the pore pressure perturbation required to make the existing fractures/fault unstable, with varying α and ν . Clearly, the results are more sensitive to α than ν . This is reasonable because α determines the pore pressure effects, thus, directly affecting the position and size of the Mohr circles. Figure C-1b shows the similar analysis with a constant $\nu = 0.25$, and varying depletion and α . As expected, depletion and α are affecting the results. For the initial reservoir with minimal depletion, shear failure would occur in the Bakken with a pore pressure perturbation <500 psi. However, when the reservoir is depleted approximately 4500 psi due to prior production, the prediction becomes sensitive to α and requires higher pore pressure perturbation when α is lower. On the other hand, with a constant α , shear failure is more easily achieved for a reservoir with less depletion.

Dohmen et al. (2013) investigate the importance of depletion effects and the pore pressure perturbation required to cause shear failure in the vicinity of well Y. Although the result of our analysis is generally consistent with theirs, our respective analyses differ in several ways. First, we estimate $S_{h\min}$ from direct measurements and then estimate the change of $S_{h\min}$ associated with depletion effects. In contrast, they estimated $S_{h\min}$ using a general empirical relation based on bilateral-constraint (the horizontal stress is related to the vertical stress by a term $\nu/(1-\nu)$). As the bilateral-constraint is of questionable applicability for predicting (Zoback [2007], pp. 292–295), we argue that using measured values of $S_{h\min}$ is preferable. Second, we use physical properties based on lab measurements on the Middle Bakken samples, rather than estimated values. Third, our analysis uses the specific fault orientations determined from the seismicity trends and focal plane mechanisms. Finally, based on the focal plane mechanisms, we use an initial stress state with $S_{H \max}$ slightly smaller than S_v whereas Dohmen et al. (2013) assume a stress state representing a pure



Figure C-1. Sensitivity analysis of required pore pressure elevation for shear slip occurrence along the representative fracture/fault (see Table 2), with coefficient of friction of 0.6. (a) Varying Biot coefficient and Poisson's ratio, with 4453 psi reservoir depletion. (b) Varying Biot coefficient and reservoir depletion, with constant Poisson's ratio of 0.25.

Table C-1. Mineralogy of core samples from the Middle Bakken and their bulk modulus.

	Quartz	Calcite	Clay
	(Mavko et al., 2009)	(Mavko et al., 2009)	(Vanorio et al., 2003)
K (GPa)	37	$70.2 \\ 0.525$	12
%	0.29		0.185

normal faulting stress regime. The results presented in Figure C-1 demonstrate that our analysis indicates that microseismic events along the well Y would have occurred with or without depletion.

References

- Aki, K., and P. G. Richards, 2002, Quantitative seismology: Theory and methods: University Science Books.
- Dohmen, T., J. Zhang, C. Li, J. P. Blangy, K. M. Simon, D. N. Valleau, J. D. Ewles, S. Morton, and S. Checkles, 2013, A new surveillance method for delineation of depletion using microseismic and its application to development of unconventional reservoirs: Presented at SPE Annual Technical Conference and Exhibition, SPE 166274.
- Engelder, T., and M. P. Fischer, 1994, Influence of poroelastic behavior on the magnitude of minimum horizontal stress, S_h in overpressured parts of sedimentary basins: Geology, **22**, 949–952, doi: 10.1130/0091-7613(1994) 022<0949:IOPBOT>2.3.CO;2.
- Fehler, M., L. House, and H. Kaieda, 1987, Determining planes along which earthquakes occur: Method and application to earthquakes accompanying hydraulic fracturing: Journal of Geophysical Research, 92, 9407–9414, doi: 10.1029/JB092iB09p09407.
- Fisher, M., J. Heinze, C. Harris, C. Wright, and K. Dunn, 2004, Optimizing horizontal completion techniques in the Barnett shale using microseismic fracture mapping: Presented at SPE Annual Technical Conference and Exhibition, SPE 90051.
- Gerhard, L. C., S. B. Anderson, and D. W. Fischer, 1990, Petroleum geology of the Williston Basin: Part II: Selected analog interior cratonic basins, *in* M. W. Leighton, D. R. Kolata, D. F. Oltz, and J. J. Eidel, eds., Interior cratonic basins: AAPG Memoir 51, 507– 559.
- Hiramatsu, Y., and Y. Oka, 1966, Determination of the tensile strength of rock by a compression test of an irregular test piece: International Journal of Rock Mechanics and Mining Sciences & Geomechanics Abstracts, 3, 89– 90, doi: 10.1016/0148-9062(66)90002-7.
- Mavko, G., T. Mukerji, and J. Dvorkin, 2009, The rock physics handbook: Tools for seismic analysis of porous media: Cambridge University Press.
- Maxwell, S., T. Urbancic, N. Steinsberger, and R. Zinno, 2002, Microseismic imaging of hydraulic fracture complexity in the Barnett shale: Presented at SPE Annual Technical Conference and Exhibition, SPE 77440.
- Moos, D., G. Vassilellis, R. Cade, J. Franquet, A. Lacazette, E. Bourtenbourg, and G. Daniel, 2011, Predicting shale reservoir response to stimulation in the Upper Devonian of West Virginia: Presented at SPE Annual Technical Conference and Exhibition, SPE-145849.
- Nur, A., and J.D. Byerlee, 1971, An exact effective stress law for elastic deformation of rock with fluids: Journal

of Geophysical Research, **76**, 6414–6419, doi: 10.1029/JB076i026p06414.

- Olsen, T., E. Gomez, D. McCrady, G. Forrest, A. Perakis, and P. Kaufman, 2009, Stimulation results and completion implications from the consortium multiwell project in the North Dakota Bakken shale: Presented at SPE Annual Technical Conference and Exhibition, SPE 124686.
- Peška, P., and M.D. Zoback, 1995, Compressive and tensile failure of inclined well bores and determination of in situ stress and rock strength: Journal of Geophysical Research: Solid Earth, **100**, 12791–12811, doi: 10 .1029/95JB00319.
- Phillips, W., J. Rutledge, T. Fairbanks, T. Gardner, M. Miller, and B. Schuessler, 1998, Reservoir fracture mapping using microearthquakes: Austin chalk, Giddings field, TX and 76 field, Clinton Co., KY: SPE Reservoir Evaluation & Engineering, 1, no. 2, 114–121, doi: 10 .2118/36651-PA.
- Rutledge, J.T., W.S. Phillips, and B.K. Schuessler, 1998, Reservoir characterization using oil-production-induced microseismicity, Clinton County, Kentucky: Tectonophysics, **289**, 129–152, doi: 10.1016/S0040-1951(97) 00312-0.
- Sturm, S., and E. Gomez, 2009, Role of natural fracturing in production from the Bakken Formation, Williston basin North Dakota: Presented at AAPG Annual Convention and Exhibition, 50199.
- Vanorio, T., M. Prasad, and A. Nur, 2003, Elastic properties of dry clay mineral aggregates, suspensions and sandstones: Geophysical Journal International, 155, 319– 326.
- Zoback, M., C. Barton, M. Brudy, D. Castillo, T. Finkbeiner, B. Grollimund, D. Moos, P. Peska, C. Ward, and D. Wiprut, 2003, Determination of stress orientation and magnitude in deep wells: International Journal of Rock Mechanics and Mining Sciences & Geomechanics Abstracts, 40, 1049–1076, doi: 10.1016/j.ijrmms.2003.07 .001.
- Zoback, M. D., 2007, Reservoir geomechanics: Cambridge University Press.



Yi (Alec) Yang received a B.S. in geology from Peking University, China, and an M.S. in petroleum engineering from Stanford University, which is where he is pursuing a Ph.D. in geophysics. His Ph.D. research focuses on unconventional reservoir development, particularly on using the

geomechanics and microseismic to evaluate and optimize multistage hydraulic fracturing stimulation. His research interests also include lab study of the mechanical and transport properties of unconventional reservoir rocks and their application to reservoir development. He currently works as a petrophysicist for Shell.



Mark D. Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He conducts research on in situ stress, fault mechanics, and reservoir geomechanics with an emphasis on shale gas, tight gas, and tight oil production. He is the author of *Reservoir Geomechanics*, published in 2007 by Cambridge University Press. He is the author/coauthor of more than 300 technical papers and holds five patents. He served on the National Academy of Engineering committee investigating the Deepwater Horizon accident and the Secretary of Energy's committee on shale gas development and environmental protection. He is currently serving on the National Academy of Sciences Advisory Board on drilling in the Gulf of Mexico.