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Key Points:

- The expanded microseismic catalog from the iMLT provides more easily interpretable spatiotemporal evolution of the microseismicity
- We identify two distinct clusters that are closely related to the injection activity both spatially and temporally
- One cluster is triggered by the reactivation of a preexisting fault, and the other one is controlled by shear failures of natural fractures

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Microseismic Monitoring of Stimulating Shale Gas Reservoir in SW China: 2. Spatial Clustering Controlled by the Preexisting Faults and Fractures

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Abstract Microseismic monitoring is crucial to improving stimulation efficiency of hydraulic fracturing treatment, as well as to mitigating potential induced seismic hazard. We applied an improved matching and locating technique to the downhole microseismic data set during one treatment stage along a horizontal well within the Wei yuan shale gas play inside Sichuan Basin in SW China, resulting in 3,052 well-located microseismic events. We employed this expanded catalog to investigate the spatiotemporal evolution of the microseismicity in order to constrain migration of the injected fluids and the associated dynamic processes. The microseismicity is generally characterized by two distinctly different clusters, both of which are highly correlated with the injection activity spatially and temporally. The distant and well-confined cluster (cluster A) is featured by relatively large-magnitude events, with ~ 40 events of $M - 1$ or greater, whereas the cluster in the immediate vicinity of the wellbore (cluster B) includes two apparent lineations of seismicity with a NE-SW trending, consistent with the predominant orientation of natural fractures. We calculated the b-value and D-value, an index of fracture complexity, and found significant differences between the two seismicity clusters. Particularly, the distant cluster showed an extremely low b-value (~ 0.47) and D-value (~ 1.35). We speculate that the distant cluster is triggered by reactivation of a preexisting critically stressed fault, whereas the two lineations are induced by shear failures of optimally oriented natural fractures associated with fluid diffusion. In both cases, the spatially clustered microseismicity related to hydraulic stimulation is strongly controlled by the preexisting faults and fractures.

1. Introduction

Hydraulic fracturing has been extensively used for the development of unconventional oil and gas reservoirs. Pressurized fluid is injected into the reservoirs to create a connected fracture network through the complex interaction of the induced hydraulic fractures with the natural fracture system. This process typically induces microseismic events of low magnitude in the range from -4.0 to 0.0 (Warpinski et al., 2012), which have been prevalently used to quantitatively interpret fracture geometry associated with hydraulic fracturing stimulation over the last decade (Maxwell et al., 2010).

Shale reservoirs typically show high levels of vertical and lateral heterogeneity (Maxwell, 2011). As a consequence, the seismic response to hydraulic stimulation can vary significantly along both vertical and lateral directions. Successive stages within the same treatment well may produce distinctly different microseismicity, in terms of both number and spatial distribution. It is widely recognized that the overall stress state and abundance of mechanical interfaces govern the propagation of hydraulic fractures (Busetti et al., 2014; Busetti & Reches, 2014). Additionally, aseismic deformation could be a significant term in the hydraulic fracture energy budget, especially in the clay-rich formations (Barros et al., 2016; Goodfellow et al., 2015; Guglielmi et al., 2015), which results in lack of microseismic events in certain areas. Hydraulic fracturing treatment may also occasionally trigger unintended large seismic events with magnitude greater than zero through reactivating critically stressed faults. Felt earthquakes associated with hydraulic fracturing have been documented in a few places worldwide, such as the Western Canada, Europe, and southwestern China (Atkinson et al., 2016; Bao & Eaton, 2016; Clarke et al., 2014; Lei et al., 2017). Overall, it remains a great challenge to fully understand the complex interaction between the injection-driven fracture creation and natural fracture system.

It is generally acknowledged that microseismic events are predominantly brittle failures that correspond to repeated shear slippages on the preexisting natural fractures or mechanically weak planes (Rutledge & Phillips, 2003; Rutledge et al., 2004). Small-magnitude events are much more abundant than large events, attributed to the power law scaling of earthquake occurrence with magnitude. However, these events are commonly not locatable or even detectable due to low signal-to-noise ratio (SNR). Such an incomplete catalog of microseismic events used for fracture mapping may lead to misinterpretation of the fracture geometry. For instance, the frequently reported viewing-distance bias, that is, the detection threshold generally increase as a function of distance from monitoring array, may lead to apparent asymmetry of hypocentral distribution (Warpinski et al., 2012). Furthermore, it is difficult to resolve the potential hydraulic fractures from the scattered distribution of sparse events. Moreover, interpretation of fracture geometry can also be compromised by the accuracy of microseismic event locations (Zimmer et al., 2011). The overall stimulated reservoir volume derived from the dispersed microseismic events is commonly overestimated, not to mention the extent and complexity of hydraulic fractures therein. The scattered event locations may result in apparent fracture complexity, that is, the cloud of events being assumed to represent complexity when in fact the events could well lie in a plane. As a consequence, a more complete and unbiased catalog that contains the diminutive but abundant low-magnitude events is of paramount importance for the accurate interpretation of the fracture geometry and can provide valuable clues to the mechanisms of the hydraulic fracture process.

In addition to the spatiotemporal distribution, the statistical analysis of microseismicity can also help us better understand the dynamic processes associated with fracturing. The size distribution of microseismicity, quantified by the Gutenberg-Richter *b*-value, can provide insights into the prevailing effective stress regime in the vicinity of the events and is increasingly used in microseismic interpretation. Previous microseismic studies have shown that *b*-value of ~ 1 is usually related to fault reactivation within seismically active region, whereas *b*-value of ~ 2 corresponds to hydraulic fracture growth and its interaction with natural fractures (e.g., Downie et al., 2010; Eaton et al., 2014; Wessels et al., 2011). Usually, it is difficult to obtain robust estimates of *b*-values and its temporal evolution from microseismic data sets because of the small-magnitude range and the scarcity of events. Another property of seismicity that has been shown to follow a power law distribution is the *D*-value (Grob & van der Bann, 2011; Verdon et al., 2013), a spatial distribution analysis that quantifies the shape and clustering of microearthquake clouds and thus the level of fracture complexity. The temporal variations of the *b*-value and *D*-value can shed light on changes of the stress state and the evolution of hydraulic fracture network.

In this paper, we report a case study of downhole microseismic monitoring during one stage of a hydraulic fracturing treatment along a horizontal well of Weiyuan shale play in the southern Sichuan Basin, China (Figure 1a). Weiyuan area has been one of the most favorable targets for shale gas exploration and development in China (Jin et al., 2013). The target formation of this study is the Lower Cambrian marine shale with a thickness of ~ 300 m at a depth of $\sim 3,000$ m, which contains a set of organic-rich black shales and is the main source of the shale gas reservoir (Borkloe et al., 2016).

The complex tectonic history in the study area has resulted in very complex structures with extensive folding and faulting (Liang et al., 2015), which poses a great challenge for shale gas exploitation. The shale play is characterized by strong stress anisotropy with differential stress up to 24.7 MPa, with the orientation of the maximum principal horizontal stress being roughly N90°E, according to the image well logging analysis (Figure 1a). Multiscale natural fractures and strike-slip faults are commonly observed with strike directions oblique to the orientation of maximum stress, predominantly in the range N40°–60°E (Figure 1a). While the high differential stress is unfavorable for the generation of complex fracture geometry, the orientation of maximum horizontal principal stress oblique to pervasively existing natural fractures, along with the high content of brittle minerals, creates a scenario well suited to the development of complex fracture networks.

This paper is organized as follows. First, we give an overview of the microseismic monitoring experiment and a brief introduction on the improved matching and locating technique specifically tailored for a downhole array configuration in section 2. This approach leads to a tenfold increase in the number of detected microseismic events when compared to the conventional processing. Next, we present a detailed analysis of the spatiotemporal evolution of the expanded microseismicity in section 3. We also analyze the statistical characteristics in the distribution of magnitude sizes (*b*-value) and spatial hypocenter locations (*D*-value)

Figure 1. (a) Location of the Wei yuan shale gas play (solid red square). According to the image well logging analysis, the orientation of the local maximum principal stress (magenta arrows) and the strike of the prevalent natural fractures (red arrows) are $N90^{\circ}E$ and $N40^{\circ}-60^{\circ}E$, respectively. (b) The 3D view of the experiment geometry. The wellhead of the monitoring well (pink line) is laterally separated from that of the treatment well (black line) by about 60 m. The downhole monitoring array consists of 20 levels of triaxial 15 Hz geophones at a depth from 2,120 to 2,405 m with sensor spacing of 15 m, about 300 m above the perforation shots of the studied treatment stage (solid red ellipsoids). The distance between the perforation shots and the lowest geophone is ~ 500 m.

with the large number of microseismic events, which provide useful aids to the interpretation of the microseismicity. Finally, we discuss how our results contribute to the current understanding of induced seismicity and shed light on the complex interactions between fluid and rocks that create and propagate fractures.

2. Data and Methodology

2.1. Microseismic Monitoring Experiment

The schematic diagram of the wells and geophone positions is shown in Figure 1b. Typically, horizontal wells are drilled in the direction of the minimum horizontal principal stress, in order to create multiple transverse fractures during the subsequent fracking process and thus maximize exposed pay zone, since the created fractures tend to follow with the direction of the maximum principle horizontal stress. Yet in the case of this study, the horizontal well (black line) is drilled along the NW-SE direction, which is approximately perpendicular to the orientations of the existing faults/fractures, to intersect a maximum number of natural fractures and enhance the fracturing stimulation effect. There are 19 treatment stages along the 1,900 m long horizontal section. The target shale formation has a small dip of 5° . Hydraulic fracturing treatment was performed between 28 October and 10 November of 2014, with each stage lasting approximately 3 hr. The completions were monitored using a variety of microseismic monitoring arrays, including a downhole array consisting of 20 levels of triaxial 15 Hz geophones (purple triangles in Figure 1b) deployed in a nearby vertical monitoring well (pink line) at a depth from 2,120 to 2,405 m, with a sensor spacing of 15 m and a sampling rate of 2,000 Hz.

2.2. Expanded Microseismic Catalog

The continuous downhole data set was first processed with the standard short-term and long-term average ratio (STA/LTA) detector, resulting in a total of 6,445 potential events over the course of treatment. Figure 2 presents the hypocentral distribution of microseismic events, which are color coded by stage number and scaled by local magnitude. It is noted that only events with local magnitude greater than -2 are shown for the sake of clarity. Despite of similar treatment strategy across all the 19 stages, the seismic response is highly variable (Figure 2). Instead of uniformly distributed along the treatment horizontal well, the microseismicity is distributed in several clusters, most notably the one near the toe region (blue ellipsoid) but also the one around the heel area (red ellipsoid). The clustering of microseismicity implies that the stimulation might be strongly controlled by the preexisting natural fault/fracture system. Interestingly, the microseismic activity near the toe region persists throughout the whole treatment course (Figure 2a). Since the event locations and

Figure 2. Hypocentral distribution of microseismic events from standard short-term and long-term average ratio detector for (a) treatment stages 1 to 18 and (b) the nineteenth treatment stage. Event dots are color coded by stage number and scaled by local magnitude. It is noted that only events with local magnitude greater than -2 are shown for the sake of clarity.

the structure within the toe-ward cluster cannot be well resolved using the heel-ward, single-well monitoring array, its spatiotemporal evolution and possible driving mechanism remain enigmatic. In this study, we focus on the microseismicity around the heel region to investigate the possible interaction between fracking fluid and the preexisting natural fault/fracture system (Figure 2b). This seismic cluster mainly occurred during the last stage (the nineteenth stage) and is close to the downhole monitoring array (~ 500 m), resulting in smaller location uncertainty and lower detection threshold. Moreover, it displays features of both fault reactivation and newly created hydraulic fracture network.

The treatment of the last stage started around UTC 10 November 2014, 08:00, and lasted for about two and a half hours. During this period, there are numerous microseismic events where both P and S arrivals are visible but hard to pick accurately due to low SNR and complicated waveforms. As a result, only 240 events could be confidently located based on manually picked P and S arrival times (red ellipsoid in Figure 2b), with local magnitude range from -3.0 to 1.3 . The microseismic cloud is elongated in a NE-SW orientation, which is almost perpendicular to the wellbore. A number of high-magnitude events cluster into a small volume, approximately 340 m away from the injection interval to the northeast side.

To improve the completeness of the catalog, we search for undetected events with an improved match and locate technique, which is specifically tailored for downhole array configuration. We briefly outline the technique here; the readers are referred to the companion paper and several other related studies for more details (Caffagni et al., 2016; Eaton & Caffagni, 2015; Meng et al., 2018; Zhang & Wen, 2015). We first employ an optimal set of well-located high SNR events to act as waveform templates and detect smaller events that strongly resemble templates through stacking cross-correlograms between the template waveforms and potential event signals in the continuous records over multiple stations and components. In principal, the master events should form a complete basis for all of the detectable microseismicity. In practice, we first spatially cluster the events from a standard STA/LTA detector, generally following Arrowsmith and Eisner (2006). Then, the most prolific event within in each cluster is chosen as the potential candidate of template event. Furthermore, the P wave SNR of a template event over all three components should be greater than 2. The detailed procedures for selecting template events are given in the companion paper (Meng et al., 2018). This correlation-based algorithm exploits the waveform coherence of repeating events, and therefore has high detection probability at low false alarm rate even in the presence of strong ambient noise. Then, the residual moveout in the correlograms across the array is used to locate events relative to the template event. The combination of waveform correlation-based detection and relative locations means that the detectability is

greatly enhanced and the location precision is significantly improved, especially for low SNR events. While the absolute location of the event clusters may be biased by possible mislocation of the template events, due to velocity model uncertainty, the spatial distribution of the member events in each cluster can still be recovered up to a very high precision.

This approach is particularly suitable to the single-well monitoring array that is most prevalent in hydraulic fracturing monitoring. In our study, we select 78 representative template events that are well recorded by the borehole array and have a relatively uniform spatial distribution across the seismically active volume. An additional 3,021 events were detected and located for stage 19, a tenfold increase in the number of events as compared to the standard STA/LTA detections. This expanded catalog has an apparent magnitude of completeness (M_c) of -3.0 , which is approximately 1 magnitude unit lower than the conventional catalog. This expanded catalog provides a higher level of detail in the spatiotemporal distribution of the induced microseismicity, allowing us to investigate possible relationship between the microseismicity and the fluid injection activities. Finally, we apply the collapsing technique (Jones & Stewart, 1997) to this expanded catalog. The locations of microseismic events are moved inside their confidence ellipsoids in order to reveal the fine structures of possible fractures or faults.

3. Results

3.1. Spatial Distribution of Microseismicity

Figure 3a presents the hypocentral distribution of the events from the expanded catalog. Event dots are color coded by occurrence with respect to the onset of injection and scaled by local magnitude. The spatial distribution of hypocenters displays complex structures extending several hundred meters from the injection points, with strong spatial and temporal clustering. It seems that there exist several NE extending lineations. The distribution of the microseismic events appears to be asymmetric, with an average extent of ~ 300 m in the northeast side and only ~ 100 m in the southwest side. The microseismic events are well confined within the stimulated depth interval, whose vertical extent approximately coincides with the thickness of the target formation.

Figure 3b shows the collapsed hypocenters, which exhibit much more distinct spatial lineation in both the plane (left) and depth-sectional (right) views. The reduced scatter of events reveals a more linear pattern of events that provides more evidence for the northeastward extent of the seismicity. From the spatial distribution, we observe three distinct clusters. Apart from the relatively large-magnitude seismicity to the northeast side (A in Figure 3b), we can see two clearly distinguished lineations (B1 and B2 in Figure 3b) along the strike direction of the natural fracture system, suggesting at least two parallel primary fractures developed from the injection interval. The northern cluster of the two parallel trends (B1) shows bi-wing fracture geometry, whereas the southern one (B2) shows one-sided fracture geometry. These two clusters are located near the wellbore and consist of numerous relatively low-magnitude events and probably represent small-scale failures along weak planes near the injection interval.

3.2. Temporal Evolution of Microseismicity

Figure 4a displays the treatment curves, including the calculated bottom-hole pressure (BHP, green line) and the injection rate (magenta line), against a histogram of microseismic events in 180 s bins (blue) in order to illustrate a plausible causal relationship between injection and seismicity. During the injection, the BHP was typically 73 MPa and injection rates were around $13.5 \text{ m}^3/\text{min}$. We also show the seismicity rate of the conventional catalog (sky blue) for comparison. Figure 4b displays the magnitude-time plot of the microseismic events (blue circles). To illustrate the potential difference between the cluster A and the rest of the seismicity, we also show a separate histogram and magnitude-time plot in Figure 4a (red) and Figure 4b (red circles), respectively.

The microseismic sequence appears to show three distinct phases (alternative grey shadows in Figure 4a), in conjunction with temporal variations in the BHP and injection rate. During the first phase (phase I), the injection rate rapidly increased to a stable level, whereas the BHP quickly increased to a peak value and then decreased slightly to a stable level. The successive period when the BHP and the injection rate remain quasi-steady is considered as the second phase (phase II). We refer to the shut-in period as the third phase (phase III). To further illustrate the temporal evolution of microseismicity, we select four short time

Figure 3. Hypocentral distribution of microseismic events during the nineteenth stage of hydraulic fracture treatment for (a) expanded catalog and (b) collapsed extended catalog. Map view and depth view are shown on the left and right columns, respectively. The well trajectory of the treatment well (black line) and the locations of the perforation shots are also shown for reference. Event dots are color coded by occurrence with respect to the onset of injection and scaled by local magnitude. The clusters A and B are marked by open red and blue ellipsoids, respectively. The two clearly distinguished lineations (B1 and B2) within cluster B are denoted by thick dotted blue lines. The orientations of the maximum horizontal stress (grey arrows) and the strike of the prevalent natural fractures (red arrows) are also shown for reference.

windows (T1, T2, T3, and T4) to show the snapshots of the microseismicity occurring in each period (Figure 5). Similar to Figure 3, the event dots are also color coded by occurrence with respect to the onset of injection and scaled by local magnitude.

During the first time window (T1), an intriguing observation was the temporal coincidence between abrupt increase in pumping pressure and the sharp transition from quiescence to high seismic activity within the cluster A (Figure 4b). This seismic sequence was located ~340 m away to the northeast side of the injection interval, offset and disconnected from the treatment zone (Figure 5a). In particular, the largest event (M_L 1.3) in this cluster occurred before the pumping pressure reached the peak value (UTC 10 November 2014, 08:05:53). This relatively large event eventually prompted the emergency temporary shut-down for about 10 min during the second phase to prevent potential seismic hazard (blue bar in Figure 4a). The pumping was then resumed after adding degradable particulate diverter, with a bimodal particle size distribution (60/80 meshes and 100/120 meshes). The diverter was used to temporarily isolate possible fault or macrofracture networks, thereby directing the stimulation fluids to untreated zones and enhancing fracture-network complexity. Yet this adjustment lagged behind the occurrence of this event for about 1 hr, possibly due to the time-consuming data processing and engineering decision-making. Then, the seismicity rate within the cluster A rapidly dropped to a steady level during the successive time window (Figure 5b). Interestingly, a few large-magnitude events occurred about 30 min after the pumping was stopped (Figures 4b and 5d). In total, 40 events with local magnitude larger than -1 were recorded.

Figure 4. (a) Calculated bottom-hole pressure in the treatment well (green) and injection rate (magenta) of the nineteenth treatment stage, against the seismicity rates of cluster A (red) and cluster B (blue) in 180 s bin. The seismicity rate of the conventional catalog (sky blue) is also shown for comparison. The whole stage period is divided into three successive phases (alternative grey shadows). (b) Magnitude-time plot of the events inside the region A (red circles) and the region B (blue circles) in Figure 3b. Symbols are scaled by local magnitude.

The seismicity rate of the microearthquakes occurring in the immediate vicinity of the wellbore outside the cluster A (blue in Figure 4), on the other hand, closely follows the pumping pressure and injection rate. The temporal distribution displays two prominent peaks. The first peak was coincident with the sharp increase of the pumping pressure and injection rate. The seismicity rate peaks at the time of maximum pumping pressure (T2 in Figure 4a). The spatial distribution of the microseismicity during this time window forms two lineations, which are delineated by thick dotted blue lines in Figure 5b. We then observe a nearly quasi-constant seismicity rate during the second phase when both the pumping pressure and injection rate remained steady. Figure 5c exhibits the distribution of microseismic events during the period T3 after the pumping was resumed, in which it appears that there are more scattered events around the two lineations (B1 and B2) formed during the period T2. Once the treatment was terminated, there was a significant increase in the number microseismic events within the next 10 to 15 min, with seismicity rate peak slightly lower than the first peak occurring in the second period (Figure 4a). After that, the seismicity dropped rapidly to a relatively low level. These postpumping events also show the same feature with tight spatial clustering (Figure 5d).

3.3. B-Value and Fractal Dimension

Assuming that the size distribution of microseismicity follows the Gutenberg-Richter relationship, which is given by the magnitude-frequency distribution equation:

$$\log_{10} N = a - bM \quad (1)$$

Here N is the number of events of magnitude M or greater and b is commonly referred to as the b-value that describes the relative number of large versus small events. A more complete catalog over nearly four

Figure 5. Similar to Figure 3b. Map view of the locations of the microseismic events during the four short time windows (T1, T2, T3, and T4) marked in Figure 4a.

magnitude units enables us to robustly analyze the magnitude-frequency distribution of the microseismicity. Figure 6a shows the magnitude-frequency distribution of cluster A (red) and cluster B (blue). We estimated the b -values of both clusters using least-square fitting on a log-log plot over the linear magnitude ranges, yielding b -value of 0.47 ± 0.01 and 1.38 ± 0.02 , respectively. Here we refer cluster B as the volume consisting clusters B1 and B2 and their surrounding volumes. The magnitude of completeness of both clusters shown in Figure 6 is approximately -3.0 . It is obvious that the b -value of cluster A is significantly lower than that of cluster B, indicating more abundant of larger events in cluster A. This abnormally low b -value of cluster A is comparable to that obtained in previous studies on the injection-induced seismicity in the adjacent region (Lei et al., 2013). It should be emphasized that the magnitudes of microseismic events are relatively estimated based on the peak amplitude ratio of the stacked envelope over the monitoring array with respect to the corresponding template event (see also, Caffagni et al., 2016; Meng et al., 2018). While the magnitude of small events ($M_L < -2.5$) might be slightly overestimated, it should have a negligible impact on the estimates of b -value.

We also calculate the spatial distribution of b -value with our expanded catalog. Since the microseismicity is well bounded within the formation depth, the microseismicity is projected onto a horizontal planar surface. Similar to Tormann et al. (2014), the planar surface is gridded into equally sized nodes with gridding space 10 m. For sampling of events, each node is used as a center for a circle of radius ~ 50 m. If the number of events within one circle exceeds a predefined minimum $N_{\min}$ and there is at least one event located within 10 m of the centered grid node, the b -value is estimated and assigned to the location of the node. Tormann et al. (2014) noted that uncertainty in b -value increases rapidly when calculated for less than 50

Figure 6. (a) Magnitude-frequency distribution of cluster A (red) and cluster B (blue), respectively. The open diamonds mark the magnitude range over which the best fit slope, which corresponds to b-value, was calculated. The bin spacing for both plots is 0.1 units. The b-values of the two clusters are 0.47 and 1.38, respectively. (b) Spatial distribution of b-value. The hypocentral distribution of the microseismic events is also shown (blue circles).

events. Generally, 50 events are sufficient for establishing statistically significant differences in b-values and are widely used as $N_{\min}$ (e.g., Eaton & Maghsoudi, 2015). Similarly, we used least squares fitting on a log-log plot over a dynamic magnitude range to determine the slope that corresponds to the b-value.

The b-value distribution shows strong spatial variations (Figure 6b). The b-values of neighboring nodes are inevitably correlated because the radius of each circle is significantly larger than the grid spacing, resulting in substantial data overlaps. The gridded spatial variations of b-value reveal a distinct patch of extremely low b-value (~ 0.5) around cluster A. The b-values in the other regions range from 1.3 to 1.8. Note that the relatively low b-value near the cluster edge (yellow nodes) might be artifacts resulting from small number of sampled events.

To quantify spatial clustering of seismicity, Hirata (1989) defined a spatial correlation dimension D (fractal dimension) using the spatial correlation integral:

$$C(R) = \frac{2}{M(M-1)} N(r < R) \quad (2)$$

where N is the number of unique event pairs whose separation distance r is less than R , and M is the total number of events. By plotting $C(R)$ against R on a double logarithmic coordinate, we can obtain the fractal dimension D from the slope of the linear portion of the distribution by the least squares method. As shown in Figure 7a, the fractal dimension D -values of clusters A and B are 1.35 ± 0.01 and 1.74 ± 0.02 , respectively. The D -values were lower than that of a pure planar distribution ($D = 2$), suggesting that microseismic events were distributed between a linear and a planar orientation. It is noteworthy that the collapsed technique used in this study may lead to reduced apparent complexity, that is, the cloud of events being assumed to form a linear trend when in fact the events could be located not exactly on the fracture plane. Hence, we should take caution to interpret the observed fracture complexity. We also show the D -values of the uncollapsed hypocentral distribution for comparison purpose (Figure 7b). As expected, the collapsing technique remarkably decreases the observed D -values of both clusters. Nevertheless, the D -value of cluster A of the uncollapsed hypocentral distribution is still systematically lower than that of cluster B. In addition, while we cannot quantify the effect of location uncertainty of individual event on the estimates of D -values, it is obvious that large location uncertainty will generally produce more scattered distribution of microseismic events, and hence larger D -values.

We further analyze the temporal variations of b-value (Figure 8a) and D -value (Figure 8b). Both the b-value and D -value are calculated over sliding windows of 100 events with an overlap of 50 events. Figure 8a shows the temporal variation of the b-value of cluster A (red circles) and cluster B (blue circles). The calculated b-value of each cluster as a whole is also shown for reference (dotted line). There was no obvious variation

Figure 7. Correlation integral versus distance for (a) the collapsed and (b) the uncollapsed hypocentral distribution of cluster A (red) and cluster B (blue). The fractal dimension (D-value) was calculated from the best fit slope at the distance range from 15 to 80 m (open diamonds).

in b-value of cluster A throughout the whole stage. On the contrary, the b-value of cluster B seems to be closely correlated to the treatment activity. During the first phase, we observed a relatively high b-value (~ 1.6) at the very beginning, and then the b-value gradually declined to intermediate values (~ 1.0). During the second phase, the b-value increased rapidly to relatively high level (~ 1.6) and remained quasi-steady. Note that there was a large excursion in b-value around 09:30, coinciding with the temporary stop of the treatment. Similarly, in response to the sudden termination of pumping, the b-value decreased dramatically to ~ 0.9 after injection has ceased.

Figure 8b shows the temporal evolution of fractal dimension D . The variations of D -values were more chaotic than those of the b-values, and there seemed to be no clear correlation between the two parameters. While

Figure 8. Temporal variations of (a) b-value and (b) D-value for cluster A (red circles) and cluster B (blue circles). The b-value and D-value for each cluster as a whole are also shown as dotted lines.

the D-value of Cluster A was systematically lower than that of Cluster B, the trends were quite similar. For both clusters, the D-value was relatively low during the first phase, and then increased and varied in a tight range during the second phase, suggesting that more complex fractures were created. The spatial dimension D-value of cluster A reached a minimum of ~ 1.0 , indicating more linearly aligned event hypocenters. Interestingly, the D-value of cluster A decreased dramatically from ~ 1.3 to ~ 0.9 during the postinjection period, whereas the D-value of cluster B only declined slightly to ~ 1.6 , implying linear to planar microseismic events cloud.

4. Discussion

4.1. Plausible Fault Reactivation

The most striking feature of the microseismicity is a cluster of relatively large-magnitude events to the north-east side of the injection interval in an area where microearthquakes were generated persistently over the whole injection period (cluster A). As aforementioned, several studies have shown that b-value of microseismicity related to fault reactivation during fluid injection is typically approximately 1.0, depending on the local stress state (e.g., Downie et al., 2010; Wessels et al., 2011). The extremely low b-value of this cluster (0.47 ± 0.01) strongly indicates that the persistent but intermittent seismicity within this cluster could be triggered by the reactivation of a nearby unmapped fault, as opposed to the creation of a new fault.

Currently, two distinct mechanisms, pore pressure diffusion and poroelastic stressing, are frequently invoked to account for induced seismicity related to fault reactivation during fluid injection (Ellsworth, 2013). When the wellbore is hydraulically connected to faults through stimulated fractures or even directly intersected by faults, the strength of preexisting faults will be weakened by elevated pore pressure, due to both decreased effective normal stress and reduced fault friction, allowing shearing stress to surpass fault cohesion (Chang & Segall, 2016; Segall & Lu, 2015). Undoubtedly, the diffusion of pore pressure within a fault is the primary driver in inducing seismicity, especially when an effective fluid pathway to nearby preexisting fault is available. Consequently, it has been widely acknowledged to explain moderate earthquakes associated with long-term wastewater injection into disposal wells (e.g., Lei et al., 2013; Yeck et al., 2016), as well as relatively large postinjection seismic events related to hydraulic fracturing treatment (e.g., Bao & Eaton, 2016; Clarke et al., 2014). In our case, we speculate that the increase of pore pressure may also play a dominant role in triggering the seismic swarm. Hydraulic fracturing fluids or pressurized formation waters entered the hydraulically connected fault and directly increased the pore pressure within the critically stressed fault, which promoted the pressure sensitive fault to slip, yielding a burst of relatively large-magnitude seismicity. It is noted that the large event (M_L 1.3) occurred at the very beginning of injection, even before the pumping pressure reached the maximum value. In this scenario, the instantaneous response of the possible fault to fluid injection implies that there is a strong pressure coupling with the injection interval. It is unlikely that the extension of the fault itself reaches the wellbore, since the repeating nature of the events strongly suggests repeated failures of the same fault patch within a relatively small volume of rock (Figure 3b). By contrast, its connection with the local natural fractures in the target formation induced during well stimulation may provide an alternate high-permeability pathway. Interestingly, there are a few scattered events around the cluster A during the previous treatment stage (Figure 2a), suggesting that the accumulated stress of previous, adjacent stages may have developed a well-connected network of natural fractures from the wellbore to the cluster A and promoted this fault to critical stress state. The continuity of cluster B1 with cluster A during the initial pumping phase (Figure 5a) clearly indicates the existence of such a well-developed natural fracture network. It could act as a highly permeable conduit that connects the injection interval to the critically stressed fault and provides the immediate transfer of pressure over large distance.

An alternative mechanism is that a hydraulically isolated but critically stressed fault can be reactivated by a long-range transfer of stress perturbation in the solid host rock through poroelastic coupling, related to the reservoir volume expansion caused by the pore pressure increase near the injector. The static stress perturbation can promote a distant critically stressed fault, which is outside the traditional fluid flow front and thus hydraulically isolated, to fail if the fault is favorably oriented in the regional stress field. Previous studies denoted that poroelastic stressing may, in certain circumstances, play a dominant role at large distances before the diffusion of pore pressure begin to take effect and could have great impact on seismicity rate, especially in the shale formation of extremely low permeability (Deng et al., 2016; Murphy et al., 2013;

Skoumal et al., 2015). However, the full poroelastic coupling may either promote or inhibit shear slip, depending on the location and orientation of the faults relative to the injector, as well as permeability and hydraulic connectivity to the reservoir (Chang & Segall, 2016; Segall & Lu, 2015). Considering the large seismicity rate of the cluster A at the beginning of injection, we argue that the poroelastic stress perturbation might play a limited role in triggering this seismic swarm, and pore pressure diffusion through a well-connected natural fracture network to the critically stressed fault is more likely a driving mechanism for the seismicity sequence. This scenario is highly speculative, and further geomechanical modeling of specific fault geometry and background stress state is required to discern relative contributions from the two distinct mechanisms (e.g., Deng et al., 2016). For example, both poroelastic loading as well as elevation of pore pressure of the cluster A area may have been promoted by the previous, adjacent stages completed.

Moderate to large-scale faults are commonly observed within the tectonically active Sichuan basin and the adjacent regions. There are significant fault-related problems encountered by well drilling in this region, such as frequent drilling out of the target zones that complicate well completion. In addition, these faults may lead to dissipation of injection fluid and increase seismic hazard during hydraulic fracturing treatment. For instance, water injection has already induced 14 $M4.0+$ earthquakes in Zigong conventional gas field (Lei et al., 2013), which is about 40 km south of our treatment well. Most of the faults are less than 1 km in length and are generally not resolvable with reflection seismic survey. On the other hand, these faults can potentially produce felt or even damaging earthquakes, due to the high stress level and critical stress state (Lei et al., 2017). Our results suggest that proper microseismic monitoring can reveal previously unmapped small faults, and therefore has potential to mitigate seismic hazard related to completion and treatment operations, possible through a “traffic-light” monitoring system (e.g., McGarr et al., 2015).

4.2. Interaction With Preexisting Natural Fractures

The spatiotemporal evolution of the microseismicity in cluster B is distinctly different from that of cluster A, implying that different mechanism has been involved in generating microseismic events. As both the seismicity rate (Figure 4a) and the temporal variation of b -value (Figure 8a) of cluster B closely track the pumping activity, we infer that the cluster B is probably induced by shear failures of optimally oriented natural fractures in the immediate vicinity of the wellbore due to elevated pore pressure associated with fluid diffusion. This conjecture is further supported by the relatively high b -value (1.38 ± 0.02), consistent with numerous observations of induced seismicity related to hydraulic fracturing.

Natural fractures appear to control the injection stimulated volumes in the immediate vicinity of the wellbore. The hypocentral distribution obviously delineates two NE-SW linear trends extending up to hundreds of meters away from the wellbore (Figure 5b), consistent with orientations of the prevalent natural fractures. This pattern of event distribution indicates reactivations of two sets of parallel natural fractures that steer the fracture growth from being perpendicular to the minimum principal stress. Rutledge et al. (2004) also observed anomalously large-magnitude microseismic events produced by rupture of natural fractures that is oblique to the maximum horizontal stress orientation in the Carthage Cotton Valley Gas Field, Texas. In our study area, the local horizontal maximum stress is approximately aligned with the east-west direction. From the set of preexisting natural fractures of various orientations, the set most favorably oriented for the reactivation is with an azimuth approximately 30° from the direction of maximum horizontal principal stress, generally consistent with the orientation of prevalent natural fracture. Therefore, in contrast to small faults or larger fractures that are critically stressed associated with cluster A, we interpret cluster B features to represent a more discontinuous and complex population of smaller natural fractures, yielding more relatively small-magnitude events, thus, resulting in higher b -values and D -values than cluster A.

It is worthy to point out that there are only a few scattered events in the southern region of the injection interval. The monitoring bias, that is, weak events of low magnitude in this region have not been detected, is unlikely to result in this apparent asymmetry. Instead, the asymmetric propagation of hydraulic fractures is more likely to reflect strong heterogeneity of the shale gas reservoir. One possible explanation is that the major deformation in the southern region occurred aseismically such that little detectable seismic energy was released. As a matter of fact, aseismic deformation is a significant component in the hydraulic fracture energy budget, especially in the clay-rich target formations (Barros et al., 2016; Goodfellow et al., 2015). Consequently, fracture dimensions could be underestimated in this scenario.

5. Conclusions

We present a case study of microseismic monitoring during the hydraulic fracturing treatment of a horizontal well within the Weiyuan shale play in SW China. A total of 3,052 microseismic events were identified by applying an improved match and locate technique to the last stage of the treatment. We investigate the detailed spatiotemporal evolution of the observed microseismicity, as well as the size distribution (b-value) and the fracture complexity (D-value). We find two distinctly different clusters that are both closely related to the injection activity both spatially and temporarily. One distant anomalous cluster (cluster A) is populated with relatively large magnitude events ($\leq M_L$ 1.3) and shows an extremely small b-value (~ 0.47) and a low D-value (~ 1.35), implying reactivation of a preexisting critically stressed fault. On the other hand, we also observe two other hydraulically connected seismicity lineations in the immediate vicinity of the wellbore (cluster B) with a NE-SW orientation. This direction is consistent with the orientation of the predominant natural fractures, indicating that these optimally oriented fractures were activated by injected fluids that steer the fracture growth from being perpendicular to the minimum principal stress. In contrast to small faults or larger fractures that are critically stressed associated with cluster A, cluster B features more discontinuous and complex population of smaller fractures. Overall, the preexisting natural fracture/fault system plays a dominant role in generating fracture networks within the stimulated shale gas reservoir.

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