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Imaging hydraulic fractures by microseismic migration for downhole monitoring system

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It has been a challenge to accurately characterize fracture zones created by hydraulic fracturing from microseismic event locations. This is because generally detected events are not complete due to the associated low signal to noise ratio and some fracturing stages may not produce microseismic events even if fractures are well developed. As a result, spatial distribution of microseismic events may not well represent fractured zones by hydraulic fracturing. Here, we propose a new way to characterize the fractured zones by reverse time migration (RTM) of microseismic waveforms from some events. This is based on the fact that fractures filled with proppants and other fluids can act as strong scatterers for seismic waves. Therefore, for multi-stage hydraulic fracturing, recorded waveforms from microseismic events induced in a more recent stage may be scattered by fractured zones from previous stages. Through RTM of microseismic waveforms in the current stage, we can determine fractured zones created in previous stages by imaging area of strong scattering. We test the feasibility of this method using synthetic models with different configurations of microseismic event locations and borehole sensor positions for a 2D downhole microseismic monitoring system. Synthetic tests show that with a few events fractured zones can be directly imaged and thus the stimulated reservoir volume (SRV) can be estimated. Compared to the conventional location-based SRV estimation method, the proposed new method does not depend on the completeness of detected events and only a limited number of detected and located events are necessary for characterizing fracture distribution. For simplicity, the 2D model is used for illustrating the concept of microseismic RTM for imaging the fracture zone but the method can be adapted to real cases in the future.

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1. Introduction

Hydraulic fracturing is an engineering tool to efficiently recover oil/gas from unconventional hydrocarbon reservoirs of low-permeability, including tight sand gas/oil and shale gas/oil. For hydraulic fracturing, fractures are stimulated by pumping high pressure fluids into reservoirs through the treatment well. During the fracturing process, fractures are created by shear or tensile failure generating observed induced microseismic events. Microseismic signals can be observed by surface or downhole monitoring geophones. Compared to (near) surface geophones, downhole geophones installed in a borehole close to the fracturing well are more often used for microseismic monitoring because microseismic signals have higher signal to noise ratio (SNR). Microseismic events are distributed approximately around the face and tips of fractures, thus the microseismic cloud provides insight into fracture location, height, length, orientation, and complexity (Maxwell et al., 2010). Generally, the main purpose of microseismic monitoring is to know how fractures are created, where they are distributed, and the characteristics of fractures. Using microseismic monitoring, fracturing design can be optimized in order to improve the success ratio of hydraulic fracturing and to avoid triggering large microseismic events along pre-existing faults (Maxwell, 2013).

For microseismic monitoring, the current efforts are generally focused on detecting microseismic events, determining their locations and focal mechanisms. Hydraulic fracture distribution, as well as stimulated reservoir volume (SRV) is generally determined by microseismic locations (Urbancic et al., 1999; Mayerhofer et al., 2010). The more accurate the microseismic locations, the better the fracture distribution is characterized. Generally, two categories of microseismic location methodologies exist: (1) arrival-based location methods and (2) migration-based location methods. In the case of high SNR (Daku et al., 2004), microseismic locations are determined by picking first arrivals and then finding optimal solutions by fitting absolute arrival times or arrival times

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differences. The other category is known as the migration-based approach by treating the "bright spot" as the seismic location after stacking seismic energy on each node in the space domain that seismic events may occur (Kao and Shan, 2004; Drew et al., 2005; Eisner et al., 2010; Chambers et al., 2010). For downhole microseismic monitoring, back azimuth information of microseismic event needs to be used to constrain location in addition to first arrivals. By combining microseismic locations with source mechanisms, it is helpful for interpreting fracture distribution and understanding fracturing process (Gharti et al., 2011; Zhebel and Eisner, 2014). However, some microseismic events may be too weak to be detected and for some reservoir layers hydraulic fracturing may not necessarily induce microseismic events (Reshetnikov et al., 2010a,b; Das and Zoback, 2011; Zoback et al., 2012). As a result, the fracture network depicted solely by microseismic locations is biased (Johri and Zoback, 2013; Sicking et al., 2012; Yang and Zoback, 2014). In fact, after hydraulic fracturing, some fractures are filled with proppants and become strong scatterers for seismic waves. Thus, for multi-stage fracturing, fractured areas in previous stages can act as scatterers for microseismic events induced by fracturing in later stages. As a result, coda waves of microseismic events in later stages may contain information related to fractured zones in previous stages. In this study, we will explore the possibility of using these scattered waves to characterize the fractured zones.

It is known that seismic migration is the most significant process in seismic exploration because of its ability to image the subsurface structure using various kinds of wavefield. Prestack depth migration has developed from Kirchhoff migration and beam migration to one-way wave-equation migration and reverse time migration (Schneider, 1978; Hill, 1990; Claerbout, 1971; Baysal et al., 1983). In comparison, RTM is more suitable for imaging complicated structures because of its ability to handle various kinds of wavefield including reflected, refracted, diffracted, turning and multiple waves.

In recent years, the concept of seismic migration developed in seismic exploration with active sources has already been applied to passive earthquake sources to image structure discontinuities in the earth at various scales. Chavarria et al. (2003) used both scattered P- and S-waves of recorded waveforms from earthquakes recorded in the pilot well of the San Andreas Fault Observatory at Depth (SAFOD) to image the fault zone structure through Kirchhoff migration. Zhang et al. (2009a) used scattered P-waves of earthquake waveforms to image reflectors around the SAFOD site through a generalized Radon transform. Reshetnikov et al. (2010a) imaged the San Andreas Fault structure by applying the Fresnel volume migration method to earthquake waveforms recorded by downhole sensors. Reshetnikov et al. (2010b) also applied the Fresnel volume migration method to induced high-frequency microseismic waveforms from the German Continental Deep Drilling program to obtain the fault structure.

In this study, we will test the ability of using microseismic events to image fractured zones by the RTM method from scattered waves in microseismic recordings. For simplicity, we assume the fractures and microseismic events are located in the same two-dimensional plane as the downhole sensors, but the method can be adapted to a more generalized three-dimensional case. We test the feasibility of this method using different configurations of microseismic event locations and sensor locations as well as different synthetic models.
Fig. 3. RTM imaging result from 8 individual microseismic events (denoted by asterisks) for the model setup in Fig. 1.
2. Microseismic reverse time migration method

For downhole microseismic monitoring, a string of seismic sensors is installed in a borehole for monitoring microseismic events. In this case, the configuration of seismic sensors and sources is similar to the vertical seismic profile (VSP) system except the sources are located around reservoirs for microseismic monitoring while they are located on surface for VSP. For this reason, we can adapt the VSP RTM method (Sun et al., 2011; Xiao and Leaney, 2010) to downhole microseismic monitoring. The conventional reverse time migration method consists of four generalized steps: (1) stimulate the source and forward propagate the source wavefield, (2) set the microseismic recordings as boundary conditions and backward propagate the wavefield, (3) apply the imaging condition to the forward-propagating wavefield and the backward-propagating wavefield and get the imaging result for this microseismic event, and (4) sum over imaging results from all events to get the final migration image.

Here, we formulate the RTM method based on a 2D acoustic wave equation (Zhang and Sun, 2008; Sun et al., 2011). For the borehole array, we need to compute forward-propagating wavefield $p_F$ with event originating at $(x_s, z_s)$ by

$$\left(1 \frac{\partial^2}{\partial t^2} - \nabla^2\right)p_F(x, z; t) = \delta((x, z) - (x_s, z_s))f(t)$$

(1)

In the above equation, $c = c(x, z)$ is the velocity model, $f(t)$ is the microseismic source signature, and $\nabla^2$ is Laplace operator.

For the common-event recordings $D(x, z; x_s, z_s; t)$ by borehole array at $(x, z)$, we need to back propagate wavefield $p_R$ based on the following equation:

$$\left\{ \begin{array}{l} \left(1 \frac{\partial^2}{\partial t^2} - \nabla^2\right)p_R(x, z; t) = 0 \\ p_R(x = x_s, z; t) = D(x_s, z; x_s, z_s; t) \end{array} \right.$$  

(2)

To simulate both the source wavefield and the receiver wavefield, we adopted the finite difference method (FDM) to solve the above equations with perfectly matched layer (PML) boundary condition.

The imaging condition for the conventional RTM is zero-lag cross-correlation of the source wavefield and the receiver wavefield. The images are given by

$$I(x, z) = \int_0^t S(x, z, \tau)R(x, z, t - \tau)d\tau$$

(3)

where $t$ is time, $S$ and $R$ denote the forward-propagating source wavefield and backward-propagating receiver wavefield at spatial coordinate $(x, z)$, and $I(x, z)$ represents the imaging result at $(x, z)$. The final migration image is obtained by stacking the images for each event.

The major drawback of conventional RTM is the low-frequency noise caused by cross-correlation of unwanted wavefield, which adversely affects the imaging resolution. Thus, the suppression of low-frequency noise is an active research area in RTM and many methods have been proposed (Baysal et al., 1984; Loewenthal et al., 1987; Guitton et al., 2006; Zhang and Sun, 2008; Yoon and Marfurt, 2006). In this study, we adopted the wavefield-separation method (Liu et al., 2007, 2011; Xiao and Leaney, 2010), which applies the cross-correlation imaging condition to source wavefield and receiver wavefield at different directions, as follows,

$$I(x, z) = \int_0^t S^*(x, z, \tau)R^*(x, z, t - \tau)d\tau$$

(4)
Here, the superscripts “+” and “−” denote the different directions along the horizontal or vertical directions.

3. Synthetic test of downhole microseismic migration method

For simplicity, we assume that microseismic sources, downhole sensors and fractures are located in a 2D plane and accordingly design a 2D acoustic model for testing the microseismic migration method introduced in the above section. Furthermore, we assume that both source locations and velocity model are known in the numerical testing of the method.

Fig. 1 shows the configuration of microseismic events, downhole sensors and an oval-shaped fracture. The fracture is located at $X = 1000 \text{ m}$ and is assumed to be induced by a previous hydraulic fracturing stage. Thirty-six sensors are installed in the monitoring well at $X = 445 \text{ m}$. The sensors range in depth from $Z = 975 \text{ m}$ to $Z = 2025 \text{ m}$ with a spacing of $30 \text{ m}$ from top to bottom. Other symbols are the same as those in Fig. 3.

We used a 40 Hz Ricker wavelet as the source to model synthetic waveforms based on the seismic acoustic equation. The
common-event recordings are 2 min long. A 10th-order accuracy central difference stencil is applied to solve the acoustic equation with the perfectly matched layer (PML) boundary condition. From the snapshot of forward-propagating source wavefield at t = 0.1786 s (Fig. 2a) and the recordings (Fig. 2b), the scattered waves from the fractured zone can be clearly seen. For microseismic migration, the background velocity model is used. The respective RTM imaging results for 8 individual microseismic events are shown in Fig. 3. All images clearly reveal that there exists an impedance anomaly around X = 1000 m where the oval-shaped fracture is located. However, the images are different for different events, indicating that the contribution to imaging is different for each event because of their different locations relative to the fractured zone. By stacking the normalized RTM imaging result from each individual event, the fractured zone is better imaged due to the better data coverage (Fig. 4). The image of the fracture shape becomes clearer and the upper tip of the fracture is clearly imaged. In comparison, the lower part of the fracture is not imaged as well as the upper part. This is because there are observations from only 8 events distributed in a limited aperture and the sensors are located relatively higher than the fracture. As a result, sensors in the monitoring well cannot receive enough wavefield that contains information related to the lower part as well as the bottom tip of the fracture.

There are clear artifacts in the RTM imaging result for each event due to the limited spatial coverage of wavefield by using only one event (Fig. 3), and the artifacts can be suppressed by using 8 events (Fig. 4). There are also some artifacts appearing to the west of the monitoring well (Figs. 3 and 4). This kind of artifacts has also been noted when applying the RTM method to vertical seismic profile system, which is mostly caused by the limited spatial coverage of the observation system and can be alleviated by the increase of sensor spatial coverage (Sun et al., 2011).

To further test how the sensor spatial coverage affects the downhole microseismic RTM imaging result, we shift the sensors both downward and upward. For the sensors located from Z = 1575 m to Z = 2625 m, the summed RTM image becomes more accurate and the shape of the fracture zone becomes clearer because more wavefields coming from the lower part of fracture can be received (Fig. 5a). If the sensors are shifted upward to be located in the range of Z = 775 m to Z = 1825 m, the fracture is more poorly resolved especially for the lower part of the fracture (Fig. 5b). This indicates that with a larger aperture of sensors, the fracture can be better characterized because wavefield from different directions can be received.

We also test how the spacing interval of borehole sensors affect the downhole microseismic RTM imaging result. For comparison, we used 12 and 24 borehole sensors from Z = 975 m to 2025 m with an interval of 90 m and 45 m, respectively. The fracture is clearly imaged from using one event or all 8 events with 12, 24 or 36 sensors (Fig. 6). It is clear, however, that the fracture is slightly better imaged with more sensors. For the case of using only 12 sensors, arc-shaped spatial aliasing can adversely affect the imaging resolution due to the low spatial sampling of seismic
wavefield. This problem can be mitigated by seismic data reconstruction, such as the compressive sensing method (Tang, 2010).

In reality, the background model is not homogeneous and for the case of shale gas development the model can be approximated by a layer model and the hydraulic fracturing is conducted in the target shale layer. To assess how the subsurface structures affect the fracture imaging, we test two models: one by adding several layers to the homogeneous background (Fig. 7a), and the other by adding a normal fault in addition to layers to the homogeneous background (Fig. 7c). Except for the background velocity model, all the other model setup parameters are the same as those in Fig. 1. For microseismic migration in this case, we again assume the background velocity model is known. The tests using two models show that even with more complex structures in the background model, the fracture zone can still be clearly imaged (Fig. 7b, d). At the same time the layer interfaces below the microseismic events are also imaged, especially for the first layer interface (Fig. 7d). This indicates that for the real case of hydraulic fracturing, it is possible to image both fracture zone and the shale layers by using microseismic events.

In practice, microseismic signals may be contaminated by noise. To test how noise affects the imaging result, we add Gaussian distributed noise to the recordings with signal-to-noise ratio (SNR) of 2 (Fig. 8a) and 0.5 (Fig. 8c), respectively. The normalized and stacked microseismic RTM images with all 8 microseismic events show that even with noise the fracture zone can still be clearly imaged although migration images are contaminated to some degree (Fig. 8b, d). This demonstrates that the wavefield-separation imaging condition method used in microseismic RTM behaves well in suppressing the imaging noise.

It is inevitable that the microseismic event is generally associated with some uncertainty in its location and origin time. However, with more advanced microseismic location methods such as the double-difference location method (Waldhauser and Ellsworth, 2000), the microseismic event locations are very accurate and the associated uncertainties could be on the order of 10 m (Castellanos and Van der Baan, 2013; Li et al., 2013). Here, we further test how location errors affect the RTM imaging results by perturbing event locations randomly within 10 meters (Fig. 9a), 20 m (Fig. 9c) and 50 m (Fig. 9e), respectively. Fig. 9b, Fig. 9d and Fig. 9f show the normalized and stacked RTM images corresponding to perturbed event locations in Fig. 9a, Fig. 9c and Fig. 9e, respectively. Compared with the image using true event locations shown in Fig. 4, the RTM image is almost not affected by randomly perturbing locations within 10 m (Fig. 9b). In comparison, greater location errors may adversely affect the RTM result and it can be seen that the fracture structures are slightly distorted by randomly perturbing locations within 20 m (Fig. 9d). If we further perturb event locations randomly within 50 m on the order of the half wavelength (Fig. 9e), the fracture zone is more distorted but it is still clearly recognizable in the migrated image (Fig. 9f).
4. Discussion and conclusions

In this study, we propose to take advantage of microseismic scattered waves and apply the RTM method to directly image the fracture zone by hydraulic fracturing. Unlike the conventional location-based fracture characterization method that uses microseismic locations as a proxy for determining the fracture distribution, the microseismic migration method that we propose to use in this study does not need to detect and use all microseismic events to accurately characterize the fracture zone. As long as a few microseismic events with high SNR are detected and located, they can be used to characterize the fractured zone. The numerical tests showed that with only 8 microseismic events, we are able to clearly characterize the fracture zone.

For microseismic monitoring, it is important to estimate the SRV. More importantly, it is better to estimate the effective SRV where the proppants exist and fractures are conductively connected (Mayerhofer et al., 2010; Johri and Zoback, August 2013). However, for the zone where the microseismic events are detected and located, it does not necessarily indicate the existence of...
proppants and opened fractures there. Therefore, it has been a challenge to use microseismic monitoring to characterize where proppants migrate. With the microseismic migration method, it is possible to differentiate the region with or without proppants and opened fractures. Even if the region is associated with microseismic events, if it does not show strong scattering effect the fractures may be closed due to the lack of support by proppants.

We showed that for different sensor positions relative to the fracture zone, the RTM imaging result is different. The monitoring system having better spatial sensor coverage can better image the fracture zone. Therefore, if it is possible, the sensors should be installed around the same depth zone of fracturing. It is also noted that different sensor spacing intervals also affect the imaging result and for the case of large spacing interval the spatial aliasing caused by low spatial sampling of the wavefield will impart the imaging resolution. In addition to imaging the fracture zone, from different synthetic tests it is also noted that the backward-propagating wavefield is focused at the source locations (Fig. 3).

In real cases, the microseismic signals are contaminated with noise to some degrees. The synthetic tests by adding different levels of noise to microseismic recordings show that the wavefield-separation imaging condition method used in microseismic RTM can satisfactorily deal with the noisy data to recover the fractured zone. We also test how microseismic event location errors affect the RTM imaging results and it shows that the fracture zone can be biased to some degree but can still be clearly imaged even when the event locations are randomly perturbed within 50 m, approximately on the order of half wavelength. With more advanced microseismic location methods available, the location errors could well be on the order of 10 s of meters. The uncertainty in the origin time bears a similar effect on the RTM imaging result as location errors. It is also possible that different microseismic events may have different source time functions. However, due to the nature of high frequency and limited bandwidth for microseismic signals, the corresponding source time functions can be well approximated by a smooth ramp function with a very short duration (Li et al., 2011a,b). In addition, most of microseismic events from the same fracking stage generally have similar focal mechanisms. Therefore, it is expected that source signatures of microseismic events would not greatly affect the RTM image.

In these tests, we assume the background velocity model used for microseismic migration is known. In real cases, the velocity model can be well estimated from sonic well logging and calibrated by perforation shots (Zhang et al., 2016). Furthermore, it can also be estimated by microseismic velocity tomography using arrival times from microseismic events (Zhang et al., 2009b). In this study, we only use the reverse time migration method to the scattered P waves, but the method can also be adapted to use scattered S waves based on the elastic wave equation. We emphasize that the goal of this study is to show the concept of microseismic RTM to image the fractures. For the application of this method to the real microseismic data, we need to adapt the microseismic RTM to the 3D case. One way to do this is to use the 3D acoustic equation and modify the Eqs. (1) and (2) accordingly to realize the 3D microseismic RTM. Another way is to apply the 2D RTM to each microseismic event that forms a 2D plane with the vertical monitoring array. By stacking RTM images from different microseismic events, we may be able to obtain the 3D RTM image. To better take care of uncertainties in the origin time, location and source signature of microseismic event, we could apply the elastic reverse time migration imaging with both microseismic scattered P and S waves (Xiao and Leaney, 2010). When combined with microseismic locations and focal mechanisms, microseismic migration can help us to better understand the fracture network, and thus to better optimize the fracturing design and to enhance the oil/gas recovery.

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