Tomographic fracture imaging: Examples of induced fracture and reservoir-scale observations during wellbore stimulations, Niobrara and Bakken plays, USA

Jeffrey Ross¹, Ken Parrott¹, Jan Vermilye², and Amanda Klaus²

Abstract
Classic microseismic techniques have been unable to adequately resolve many of the questions that have been asked with respect to reservoir stimulation and production in the Bakken and Niobrara unconventional resource plays as they have matured over the last few years. This has become evident especially in relation to the infill drilling and restimulation phases of field development. In support of efforts to design efficient continued development of operations in these areas, Whiting Oil and Gas has utilized a different, but related, technology to enhance understanding of the subsurface environment during and after reservoir stimulation treatments. We present two separate field examples of a novel reservoir monitoring technology that utilizes microseismic surface geophone arrays and seismic emission tomography (SET) methodologies to directly image both natural and hydraulically induced fracture systems. Tomographic fracture imaging (TFI) was developed with the goal of directly identifying and mapping active induced or natural fracture systems, as opposed to inferring them from a population of microseismic hypocenters as is done in classical microseismic data acquisition and analysis. Examples shown here consist of results from a purpose-designed array intended to monitor the stimulation efficiencies of three wellbores on a single Niobrara drill pad that was completed within a very short timeframe, and the results of a much larger reservoir-scale study showing the 4D reservoir effects of field production over a nine–month period by the TFI reprocessing of legacy microseismic data in the Bakken. These examples represent clear empirical evidence that the TFI technique is effective in detecting and localizing active fracture networks that are highly correlative to other wellbore data, even though much remains to be researched about the exact mechanisms involved in the generation of seismic energy within fracture networks.

Introduction
The history of horizontal unconventional oil and gas production cannot be told without including the parallel development of microseismic fracture stimulation monitoring. As commercially developed, microseismic monitoring has emphasized the detection of microearthquakes as an indicator of the creation of new fractures or fracture networks, essential to successful completion of an unconventional well. Attempts to correlate classic microseismic attributes such as stimulated rock volumes or fracture half-length to wellbore performance or ultimate recovery have had mixed success. Even after a decade of use within the oil and gas industry, across a number of basins and plays, much disagreement remains as to how to interpret these data and how these data can be used numerically, if at all, to aid reservoir engineers in reservoir modeling or well design. We contend that this is because reservoir engineers are primarily interested in reservoir flow characteristics, either through matrix or fractures. Microseismic hypocenters and their distributions are at best only a proxy for these networks. Of more value to a reservoir engineer would be to have a technology available that would directly reveal fracture networks and fluid flow paths, either as a result of production or reservoir stimulation operations. This is the promise of tomographic fracture imaging.

In late 2013, Whiting made the decision to test the TFI processing flow on archived conventional microseismic data acquired over Sanish Field in the Bakken play of North Dakota. Ultimately, Whiting contracted for TFI reprocessing of data associated with 20 wells across the Sanish Field, in five different areas of specific interest. After a thorough evaluation of the TFI results and a comparison with the informational content revealed by the conventional hypocenter processing of the same data, the experiment was considered to be a success.

As a result of this success, the decision was made to test the TFI procedure on a specifically designed survey in order to monitor the stimulation of a number of high-density pilot pad wells being drilled in the Niobrara play of northern Colorado. Recording of the TFI data was run concurrently with a number of other wellbore monitoring technologies, both surface and downhole, to get as complete a picture of the stimulations of these wells as possible.

Although many observations from both of these data sets are worthy of discussion, we have chosen two clear examples of calibrated and verifiable results that strongly support the TFI method’s validity. These examples are discussed in detail here.

TFI methodology
TFI utilizes streaming depth imaging (SDI), based on a modified version of Kirchhoff migration, to image the intensity and distribution of weak seismic signals emitted from reservoir depths. SDI captures both microearthquakes (Figures 1a and 1b) and low-amplitude signals that are continuous for longer time durations (Figures 1c and 1d) (Sicking et al., 2014, 2015). Imaging these very weak signals requires the use of high-quality trace filtering to suppress noise (Sicking et al., 2016). The objective of the processing is to suppress reflectivity noise and surface-wave noise without modifying the phase of the signal waveforms that are emitted at depth and travel to the receivers at the surface. The most important processing steps include cepstral filtering, median filtering, and low-cut frequency bandpass. The processing is designed to preserve signal in the 15 to 50 Hz frequency domain, important for transmission of seismic waves in the earth (Woodburn et al., 2012), and this frequency band has the highest signal transmission.

¹Whiting Oil and Gas Corp.
²Global Geophysical.

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The trace-processing workflow preserves this frequency band without phase distortion in the waveforms. Preserving waveform phase is important for SDI performance because the seismic waves generated from the same location at different times will have different waveforms. Summing the images over long time intervals requires that the signals from the same location stack up to build the signal-to-noise ratio. Knowing the bandwidth of the signals generated at depth is not as important as knowing the bandwidth of the signal that arrives at the receiver grid.

Field data for TFI is collected using either a surface array or a shallow buried grid. A velocity model is subsequently built and calibrated. This velocity model can be a simple 1D velocity model derived from a sonic log or a 3D velocity model including anisotropy, depending on the complexity of the velocity field. Statics are then computed and applied. A volume of interest is defined and divided into subvolumes called voxels, and a table of one-way traveltimes is computed from every voxel to every receiver.

When initially recorded, the time and location of microseismic signals are unknown. Traditional seismic methods first identify that a seismic event occurred and then locate and measure that event. SDI assumes that each point in time and space in the model is a potential seismic source. In order to image the signal, it is streamed through the SDI algorithm using one-way traveltimes to sequentially move out the trace data as if there were a seismic source at each voxel. For each time step, the coherence of the moved-out traces is calculated.

Coherence is a measure of the similarity between traces. The higher the coherence, the more likely that there was seismic activity in that voxel during that time window. A genuine seismic emission will result in the same waveform being received at many receivers, while noise will be less coherent across receivers if surface and reflectivity noise have been removed properly. An example of noise removal is shown in Figure 1. This example shows a single microearthquake (MEQ) from the Sanish data set (Figures 1a and 1b) and a long-duration signal from the Nibrara array (Figures 1c and 1d). Figures 1a and 1c show the signal in both the trace and the coherence domain before filtering and noise-removal processing. Figures 1b and 1d show the same signals after all filtering. This example illustrates the large signal-to-noise ratio improvement of the processing workflow: the signal is difficult or impossible to see in the trace data before filtering and does not produce a high coherence value. After filtering, the coherent arrival is visible in both the trace data and in the coherence volume. Further detailed discussion of how the trace processing affects the image is beyond the scope of this paper but is available in Sicking et al. (2016).

The sources at each voxel emit energy multiple times over the time window of recording. These emissions tend to be of a very low amplitude, but the energy accumulates over time, revealing the locations of the active fractures. The images from each of the time steps are summed into a three-dimensional image of the subsurface (Figure 2). This coherence volume is processed further to generate detailed fracture image volumes.

Fracture networks are extracted from the coherence volume based on a physical model of fracture damage zones. Seismic energy is not evenly distributed in the earth’s crust but is preferentially released on fracture/fault surfaces and in damage zones surrounding these surfaces. Fracture mechanics predict that stress concentrations are associated with fractures. Field studies (Vermilye and Scholz, 1998) and laboratory experiments (e.g., Lockner...
et al., 1991; Moore and Lockner, 1995; Janssen et al., 2001) show clear evidence for these stress concentrations, recorded in the damage zones associated with fractures.

Both natural and induced damage zones consist of rock volumes with a high density of smaller fractures that display exponentially higher densities with proximity to the main fracture surface. Natural forces, such as earth tides and tectonic, flexural, and isostatic forces are known to generate heterogeneously distributed microseismic failure events throughout brittle crust (Sicking et al., 2016). During well treatment, this natural activity is enhanced when injected fluid volumes alter the stress state around the wellbore, and seismic energy is emitted as the rock releases stored elastic-strain energy.

Because fracturing and fracture movement produce seismic emissions, it should be expected that the clouds of repeated high energy within the coherence volumes record the locations of damage zones (Figure 2a). The fracture (TFI) is extracted from this zone by computing the surface of highest amplitude within the cloud (Figure 2b). This is accomplished by searching the volume for high-amplitude ridges and collapsing the ridges to single-voxel-thick surfaces.

Fracture surfaces do not fail in a single event but do fail incrementally over time. It is to be expected that failure will occur on both induced and reactivated fractures. The fractures mapped throughout the total volume of interest are referred to as reservoir-scale TFI. We suggest that these fracture zones are activated by the propagation of fluid pressure waves due to nearby well completion or production operations and do not require fluid transmission. A reservoir-scale TFI is generated for each stage of a well completion (Figure 3a). A location repetition volume is then generated from the individual stages. Although the many individual stage TFIs can be viewed together (Figure 3b), this has limited value because the overlying TFIs obscure one another. Each voxel in a location repetition volume (LRV) represents how many times that voxel was activated in all the individual stage reservoir-scale TFIs. These location repetition numbers are summed for all stages to determine the total location repetition number (Figure 3c).

Activity on large, reservoir-scale fractures can obscure activity on smaller induced fractures that are directly connected to the wellbore. A separate workflow is used to isolate all time windows during a stage that show high levels of activity at the stage location.

Figure 2. (a) A chair-cut coherence volume. (b) The same coherence volume rendered with the reservoir-scale TFI generated from that coherence. Dashed line indicates the location of a layer boundary separating rocks of significantly different geomechanical properties. Note: this image is not from data sets discussed in this paper.

Figure 3. All Figure 3 images are a single-voxel-thick slice at the depth of the well. Well shown as a thick gray line. (a) A single-stage reservoir-scale TFI from a Bakken completion. (b) All single-stage reservoir TFIs from one job rendered together as slices at the same depth. (c) The location repetition volume (LRV) of all the single-stage TFIs at this level. The color scales show low activity with cool colors (low number of repetitions) and high activity with warm colors (high number of repetitions).
By stacking only data from these specific time intervals, the signal near the wellbore is not overwhelmed by energy release on much larger preexisting fractures that are located throughout the reservoir. These time windows are combined to generate an induced TFI volume for each stage.

**Induced fracture TFI example**

The first data example to be discussed is related to TFI results in the Niobrara Formation collected during the stimulation of three adjacent horizontal wells at three different reservoir levels. The array consisted of about 1400 stations in a hexagonal array with a spacing of 550 ft and was designed to evenly surround the wells out to a distance that ensures sufficient aperture. The velocity field derived to process the TFI volume resulted in an average detected perf shot error of less than 10 ft in the horizontal dimension and about 20 ft vertically. The data were collected to determine how each stage and perforation cluster responded to the stimulation effort and to evaluate the total hydraulic fracture effectiveness in stimulating the near-well reservoir volume.

In this case, the recorded TFI data were processed specifically to image the induced fracture network effects related to individual completion stages for each well during stimulation. The voxels that were determined to be activated during the stage treatment process were collected and reduced to tessellated surfaces, intended to represent where hydraulic fractures were created or natural fractures reactivated. These tessellated surfaces can be rendered in a three-dimensional view along the wellbore (Figure 4). This view can be used to evaluate which perforation clusters were most effective in stimulating the reservoir and to map the resulting hydraulic fractures.

Three wells were drilled and completed in late 2014 as part of a pad-drilling campaign. These particular wells were all stimulated using a different proppant tracer unique to each well, and each completion job was monitored using both a surface microseismic array designed for optimally recording TFI data and a horizontal downhole microseismic array in an adjacent wellbore (not shown). Each well was completed in 40 stages with three perforation clusters per stage utilizing a standard completion design for the local area. Well 1, the middle well of the three, was drilled in the middle production zone of the drilling pad and was the first well to be stimulated and completed. Well 2 was drilled in the uppermost zone and was completed second. Well 3 was drilled in the lowest zone and was the last to be completed. All wells were drilled from the same surface pad and were drilled from south to north. As each well was stimulated, it was left pressured up until all three wells were completed.

All three wells were spiked with different radioactive proppant tracers, with the goal of detecting where hydraulic fractures were being initiated and successfully propped. Approximately a week after completion of all three wells, each borehole was logged using spectral gamma tools to see where the proppant tracers could be detected.

Figures 4 and 5 show the three wellbores and the proppant tracer logs for the tracer used in the stimulation of well 2. Well 2 of course shows the presence of the tracer all along the wellbore, while well 3 shows a few instances where the well 2 tracer was detected. Interestingly, the well 2 tracer was not detected anywhere in well 1.

The TFI tessellated surfaces were used to evaluate the possible flow paths from the treated well to the neighboring wells in which the tracer was detected. Figure 4a shows the tessellated surfaces from well 2, stage 21 in a red-shaded color. Figure 4b shows the same with the addition of tessellated surfaces from well 3, stage 22 in a green-shaded color indicating a larger, more complicated fracture pattern developed from this stage. This fracture pattern indicates that the initiated fractures were created mostly vertically with some of the fracture growth traveling within the lower zone, but underneath well 1, ultimately intersecting the fracture surface created in well 2. This would create a flow path for the proppant tracer in the well 2 fracture to connect with the well 3 borehole in a few isolated places as shown.

Figure 5a shows a “gunbarrel” view of the wellbores in which neither the green tessellated surfaces nor the red tessellated surfaces come into contact with the well 1 borehole. Figure 5b is a map view...
of these surfaces highlighting the well 2 proppant detection logs in yellow. These surfaces intersect well 3 at stages where the proppant tracer was detected and again show that well 1 was not intersected. This would indicate that the hydraulic fractures initiated in well 2 and well 3 avoided the area around well 1, presumably due to the higher reservoir pressures from the well 1 completion.

The distribution of the proppant tracer detection across the three wells as demonstrated is strong, independent confirmation that TFI tessellated surfaces do show potential fluid flow paths from one wellbore to another. We are not aware of any other technology that is currently able to directly map these flow paths with similar precision.

Figures 4 and 5 also show the locations of MEQ hypocenters for well 2, stage 21, and well 3, stage 22, detected on a downhole, horizontal microseismic array installed on an adjacent wellbore that is not shown. The hypocenters are colored to match the associated borehole color. In Figure 5b, these events show some general agreement with the TFI surfaces, but their scatter makes clear fracture interpretation difficult. Figure 5b also shows the direction of $S_{\text{Hmax}}$ to be approximately 40 degrees west of north (which we know to be the case from other data in the field). The TFI surfaces clearly show parallel features to this azimuth as well as a feature approximately perpendicular to this. The MEQ events show some general agreement with this, but because of scatter this azimuth is not as clearly defined.

**Reservoir-scale TFI example**

Between 2010 and 2012, Whiting Petroleum operated the world’s largest permanently installed microseismic buried array across Sanish Field in the Williston Basin of North Dakota (Anderson, 2010). Covering a total area of 156 square miles, the Sanish Buried Array recorded the completion of 264 horizontal completions in both the Bakken and Three Forks formations during a 31-month period ending in October 2012. The station density of this array was low; although there were three buried receivers per station, these stations were typically about 4000 ft apart. The sparse coverage results in poor vertical resolution, but string shots were located to within an average of 75 ft of the actual location in the horizontal dimension.

One of the most valuable features of the operation of this array was that all stations were continuously recording at all times, even when and where there were no stimulation operations ongoing. Although not all of these recordings were permanently archived, the physical size of the array and the number of archived recordings over its three-year lifespan allow for the potential reuse of the data in detecting and analyzing different types of information recorded by the array than was originally intended.

It was this flexibility that allowed Whiting to submit several data sets recorded during completion jobs to Global Geophysical in order to test whether their TFI technology could be adapted for use on data that had not been acquired specifically for that purpose. Ultimately, Whiting submitted data covering five separate areas across the field, each with a different completion or reservoir issue that hopefully would be addressed by the TFI processing workflow. The ensuing discussion covers some of the results achieved in one of these areas.

One of the most productive drilling units in the Sanish Field lies on the eastern margin of the field and was chosen as a TFI candidate because of the exceptional production of one particular well, the Behr 11-34H (Figure 6, well 1). To date, the Behr well has produced more than 1 million barrels of oil and is still producing strongly at approximately 200 BOPD. Production histories for three wellbores in this spacing unit are shown in Figure 7, the Behr 11-34H (10 stage, sliding sleeve), the Maki 11-27H (18 stage, sliding sleeve), and the Jorgensen 12-27H (18 stage, sliding sleeve). It can be seen that the recorded completions for the Littlefield 12-34H (18 stage, sliding sleeve) and the Oja 14-27XH (22 stage, sliding sleeve) wells were conducted at different critical periods in the decline curves of the three subject wells, exponential decline in well 1 (Behr), late hyperbolic in well 2 (Maki), and early hyperbolic in well 3 (Jorgensen).
Although it is undoubtedly true that there is progressive reservoir pressure depletion between wells 1 and 3, encompassing a time span of 22 months, this alone is not considered to be adequate to wholly explain the differential production performances of the three wells in question. A number of attempts to geophysically discriminate the Behr well from others in this unit using 3D seismic volumetric and/or horizon-based attributes, such as curvature or anisotropy, were unsuccessful. Extraction of classic microseismic attributes, such as SRV or indicated fracture half-lengths, were also unsuccessful as the wells being studied were not the wells whose fracture stimulation was microseismically monitored.

Figure 8 demonstrates the reservoir-scale location repetition volumes (LRV) for the Bakken interval as recorded during the duration of the completions for the Littlefield (Figure 8a) and Oja (Figure 8b) wells. Reservoir-scale TFI activity is interpreted to show the system of transmissive natural fractures as they responded to changes in fluid pressure and stress, either as a result of the completion or nearby production. An LRV is constructed by summing the number of individual-stage reservoir-scale TFIs that have activity in each individual voxel and is intended to highlight areas of repeated activity. The higher the LRV number, the more seismically active the fractures are over the time of observation. Seismically active fractures are more likely to be hydraulically transmissive.

In this demonstration, a comparison is made between reservoir-scale LRVs acquired nine months apart but covering the same area. At first glance, there seems to be little visual correlation between the two data sets. However, when comparing the regions immediately adjacent to test wells 1–3, one can see a clear negative correlation.

This negative correlation is more clearly shown in Figure 9. After data normalization to account for the different number of stages for the Littlefield and Oja wells, clear and consistent differences in LRV activity can be seen along the horizontal boreholes for all of the observed wells between May 2010 (blue curve) and February 2011 (red curve). It can be seen that many of the locations exhibiting high activity in 2010 reveal much less activity in 2011 and vice versa. This is interpreted to be suggestive of major changes in the producing efficiencies of different portions of each borehole over time. Increases in relative LRV activity (and by inference individual stage productivity) over time are highlighted in green colorfill, and decreases are highlighted in red colorfill.

The relative proportions of the green highlighted zones (increase in indicated reservoir activity over time) and red highlighted zones (decrease in indicated reservoir activity over time) change dramatically between the toe and heel portions of each borehole. This observation is consistent with the expectation that, over time, toe-stage production should suffer to a greater degree than that of the heel stages due to increasing borehole restriction issues.

If we define “effective” total wellbore performance at any time to be when either curve is above a normalized relative LRV activity of 0.5, we can calculate a value for inferred wellbore production efficiency between the two data sets through time. This leads to the observation that the Behr 11-34H (well 1) had a total efficiency value of 83%, the Maki 11-27H (well 2) efficiency was 75%, and the Jorgensen 12-27H (well 3) efficiency was a poor 60%. This observation has been interpreted to be one of the primary drivers for the excellent — i.e., outperforming — production history of the Behr well in that it was more efficient at delivering oil from the entire borehole over time than its neighbors.
Conclusions

After field testing the tomographic fracture imaging procedure on a significant number of producing unconventional wells in two different basins, Whiting has concluded that there is significant, and verifiable, validity in the TFI data acquisition and processing model. We have demonstrated verification of both induced fracture and reservoir-scale geometries through the use of independent data and comparative analyses, and we are confident that these strong empirical observations support our contention that TFI is responding to reservoir fluid movement or pressure effects. It is our expectation that in the future this type of microseismic analysis will be viewed as having much greater value in constructing accurate reservoir models and understanding the short- and long-term effects of human interaction with reservoirs than is possible using the standard industry techniques used today that can only infer such details.

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Corresponding author: Jeffrey.Ross@whiting.com

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