Tomographic Fracture Imaging (TFI): Examples of induced fracture and reservoir-scale observations during wellbore stimulations, Niobrara and Bakken plays, USA

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Abstract
Classic microseismic techniques have not been able 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 re-stimulation phases of field development. In support of our efforts to design efficient continued development of our operations in these areas, Whiting Oil and Gas has utilized a different, but related, technology to enhance our understanding of the subsurface environment both during and after reservoir stimulation treatments.

We are presenting two separate field examples of a novel reservoir monitoring technology that utilizes microseismic surface geophone arrays and Seismic Emission Tomography (SET) methodologies in order 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. The examples shown here consist of both the results from a purpose designed array intended to monitor the stimulation efficiencies of three wellbores on a single Niobrara drill pad 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.

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, there is still a great deal of disagreement 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. It is our contention that this is because reservoir engineers are primarily interested in reservoir flow characteristics, either through matrix or fractures, and microseismic hypocenters and their distributions are at best only a proxy for these networks. What would be 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 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. The recording of the TFI data was run concurrently with a number of other wellbore monitoring technologies, both surface and downhole, in order to get as complete a picture of the stimulations of these wells as possible. Although there are many observations from both of these datasets that are worthy of discussion, we have chosen two clear examples of calibrated and verifiable results that strongly support the validity of the TFI method. These examples are discussed in detail below.

**TFI Imaging 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 that are emitted from reservoir depths. SDI captures both microearthquakes and low amplitude signals that are continuous for longer time...
durations (Sicking et al., 2016). Imaging these very weak signals requires the use of high-quality trace filtering to suppress noise. 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.

Field data for TFI imaging is collected using either a surface array or a shallow buried grid. A velocity model is subsequently built and calibrated, which 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 travel times 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, 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 travel times 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 it is 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 properly removed. The sources at each voxel emit energy multiple times over the time window of recording. These emissions tend to be 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 3-dimensional image of the subsurface (Figure 1, left). This coherence volume is further processed to generate detailed fracture image
Fracture networks are extracted from the coherence volume based on a physical model of fracture damage zones. Seismic energy is not evenly distributed in earth’s crust, but is preferentially released on fracture/fault surfaces and in damage zones surrounding these surfaces. Fracture mechanics predict stress concentrations associated with fractures. Both field studies and laboratory experiments show clear evidence for these stress concentrations, recorded in the damage zones associated with fractures (Vermilye & Scholz, 1998). 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. We assume that the clouds of repeated high-energy release within the coherence volumes record the locations of damage zones. The fracture is extracted from this zone by computing the surface of highest amplitude within the cloud (Figure 1, right).

During well treatment, injected fluid volumes alter the stress state around the wellbore and seismic energy is emitted as the rock releases stored elastic strain energy. Fracture surfaces do not fail in a single event, but fail incrementally over time. It is expected that failure will occur on both induced and re-activated 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 the transmission of fluid.

A reservoir-scale TFI is generated for each stage of a well completion (Figure 2A). A location repetition volume is then generated from the individual stages. Although the many individual stage TFIs can be viewed together (Figure 2B), this has limited value because the overlying TFIs obscure one another. Each voxel in the location repetition volume represents how many times that voxel was activated in all of the individual stage reservoir-scale TFIs. These location repetition numbers are summed for all stages in order to determine the total location repetition number (Figure 2C).

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. 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 in order 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 data were collected to determine how each stage and perforation cluster responded to the stimulation effort and to evaluate the total frac 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 frac 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 which also shows the stages and perforation clusters along the wellbore (Figure 3). 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 frac job was monitored using a surface microseismic array designed for optimally recording TFI data. Each well was completed in 40 stages with 3 perforation clusters per stage utilizing a standard frac 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 of the 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 the completion of all three wells, each borehole was logged using spectral gamma tools to see where the proppant...
tracers could be detected.

Figure 3 shows the three wellbores with every 5th stage in each wellbore highlighted, 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, whereas 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. The Figure 3 left panel shows the tessellated surfaces from Well 2, stages 21-23 in a green shaded color, and the right panel shows the same with the addition of tessellated surfaces from Well 3, stages 20-22 in a blue shaded color indicating a larger, more complicated fracture pattern developed from these stages. This fracture pattern indicates that the initiated fractures were created mostly vertically with some of the fracture growth travelling within the lower zone, but underneath Well 2, 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 3: The left panel shows the tessellated surfaces from Well 2, stages 21-23 in a green shaded color, and the right panel shows the same with the addition of tessellated surfaces from Well 3, stages 20-22 in a blue shaded color indicating a larger, more complicated fracture pattern developed from these stages. This fracture pattern indicates that the initiated fractures were created mostly vertically with some of the fracture growth travelling within the lower zone, but underneath Well 2, 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.](image)

The Figure 4 left panel shows a “gunbarrel” view of the wellbores in which neither the green tessellated surfaces nor the blue tessellated surfaces come into contact with the Well 1 borehole. The right panel is a map view of the surfaces and the 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 Wells 2 and 3 avoided the area around Well 1, perhaps due to the higher reservoir pressures from the Well 1 frac job.

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 flowpaths with similar precision.

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 frac jobs in both the Bakken and Three Forks formations during a 31 month period ending in October 2012. 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 frac job recordings to Global Geophysical in order to test as to whether their TFI technology could be adapted for use on data that had not been acquired specifically for that purpose. Ultimately, Whiting submitted frac recordings covering five separate areas across the field, each with a different completion or reservoir issue that would hopefully 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 5, Well 1). To date, the
Behr well has produced over 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 as Figure 6, 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 frac jobs 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 7 demonstrates the reservoir-scale “Location Repetition Volumes” (LRV) for the Bakken interval as recorded during the duration of the frac jobs for the Littlefield (upper panel) and Oja (lower panel) 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 frac 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.
In this demonstration, a comparison is made between reservoir-scale LRVs acquired 9 months apart but covering the same area. At first glance, there seems to be little visual correlation between the two datasets. However, comparative analysis of the areas of high and low relative location repetition as encountered in the regions immediately adjacent to test Wells 1-3 reveals a very high negative correlation between these two datasets (Figure 8). After data normalization to account for the different number of stages for the Littlefield and Oja wells, clear and consistent differences can be seen for all of the observation wells between May, 2010 and February, 2011.

There are a number of key observations that can be made from the presentations in Figure 8. First, there is a strong negative correlation between the May 2010 location repetition maps and February 2011 location repetition maps, highly suggestive of major changes in the producing efficiencies of different portions of each borehole over time. And second, the relative proportions of the green highlighted zones (increase in indicated reservoir activity over time) and orange
highlighted zones (decrease in indicated reservoir activity over time) change dramatically between the toe and heel halves of each borehole. This observation is in concordance 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. Lastly, as a proxy for total wellbore deliverability efficiency through time, the relative proportions of the lateral borehole length where either the early or late curves were above the 0.5 normalized location repetition value, revealed that the Behr 11-34H well had a total efficiency value of 83%, the Maki 11-27H efficiency was 75% and the Jorgensen 12-27H efficiency was a poor 60%. This has been interpreted to be one of the primary drivers for the excellent 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 having field tested 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 are confident that TFI is indeed responding to reservoir fluid movement or pressure effects. It is our expectation that in the future, this type of microseismic analysis will be seen to be of 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.