THE AMERICAN OIL & GAS REPORTER

SEPTEMBER 2014

The "Better Business" Publication Serving the Exploration / Drilling / Production Industry

Perf Shot Arrival Time Can Track SRV

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UNIVERSITY PARK, PA.–Monitoring the stimulation process to assess the stimulated reservoir volume (SRV) is one of the keys to improving well designs to achieve optimal stage and well spacing, both of which have contributed greatly to increasing estimated ultimate recoveries in Marcellus Shale wells over the past few years.

Advances in drilling techniques and well stimulation have increased EURs of Appalachian Basin unconventional gas wells from less than 3 billion cubic feet in 2007 to double or triple that number, depending on location in the play. Thus far, the suite of monitoring techniques for defining SRV includes chemical tracers, tiltmeters, 4-D seismic, and microseismic surveys.

Among these techniques, microseismic monitoring stands out in defining SRV. Because of the unique advantage of real-time monitoring and high resolution in 3-D, microseismic is becoming routine.

To date, the information that has been utilized from the microseismic record is confined largely to location information–called "dots in the box"–and focal mechanism data to define the orientation of individual microseismic events. Other techniques that move beyond dots in the box include full moment tensor inversion and time stacking of ambient noise.

The former gives some information on the extent to which microseismic events are either faults or opening-mode fractures. The latter allows for defining the fracture fairways that may contribute a great deal to draining the local SRV.

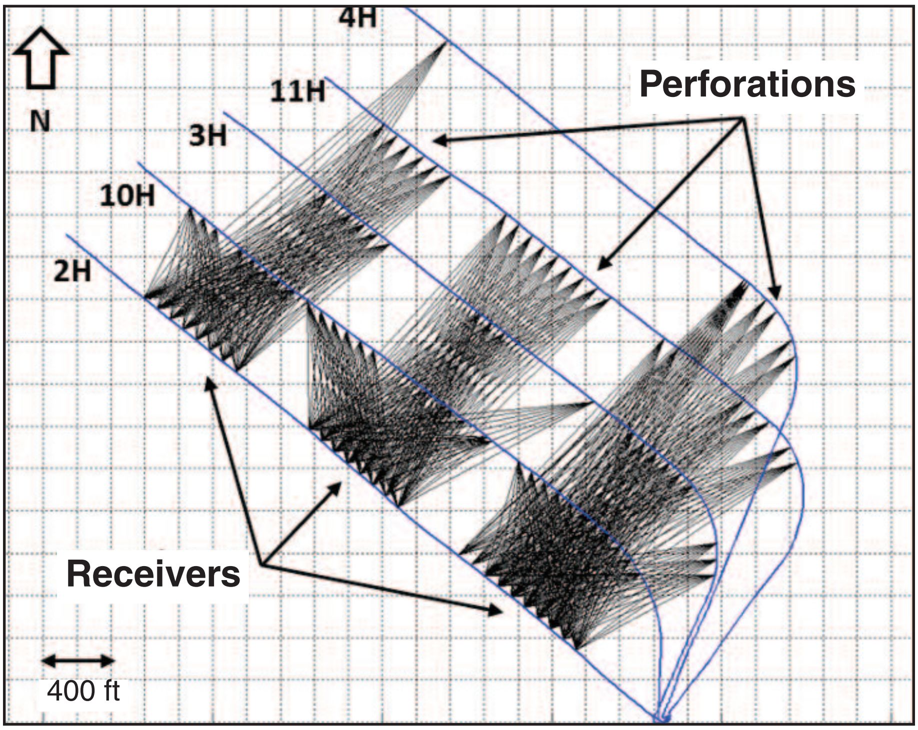
But, there are still other, useful data buried in the raw microseismic records. For example, both waveform and spectrum information are waiting to be tapped.

This article focuses on another portion of the microseismic record that is collected routinely, but largely overlooked: the perforation shot arrival times in downhole microseismic monitoring jobs. Some service companies routinely use perforation shots in their workflows to update their velocity models from stage to stage. However, the results rarely are shown to clients.

We make the case that service companies should provide this information as part of their routine deliverables, largely because a tomographic image of the reservoir can be constructed using perforation shots recorded on downhole microseismic geophones. A group of laterals in the Marcellus Shale demonstrates the advantages of this technique.

FIGURE 1

Map View of Wells in Experiment



Black solid lines are the ray paths connecting the perforations and receivers. Blue solid lines are the well trajectories.

Tomography

Tomography is a routine technique in seismology studies today. "Tomo" means slices; "graphy" means imaging. It is the same technology used for CT scans in hospitals. But instead of X-rays, geophysicists use elastic waves.

With the development of modern computers in 1970, large scale inversion problems became feasible. Seismologists use teleseismic waveforms recorded by global seismographic network stations to invert for the velocity structure of the earth, or regional stations for regional velocity structures around volcanoes, hot spots, and other features that may vary horizontally.

Similar techniques are most helpful in the oil and gas industry. For example, time-lapse monitoring of reservoir depletion is possible using active acoustic sources in one well and receivers in a neighboring well. This is the basis for cross-well tomography. The principle of cross-well tomography is simple: Seismic rays sample the travel time when passing through the object, such as a reservoir to be imaged.

If the rays from all directions passing a certain part of a reservoir–in this case, the SRV–are consistently slower or faster than other parts, this part of the reservoir can be mapped as a region of interest.

A version of cross-well tomography has been developed that utilizes perforation shots as the signal source and downhole geophone strings as the receivers. From this source/receiver configuration, users are able to follow the evolution of the SRV using a technique that may fill in the stimulated volume more completely than the "dots in a box," and may make a nice complement to time stacking ambient noise for identifying fracture fairways.

Similar to reflection seismic surveys, cross-well tomography provides an image of the target region. Cross-well tomography has a few advantages, compared with reflection seismic data. The most important is better resolution. Theoretically, one can focus on the target region (in our case, the stimulated portion of the reservoir) to boost the resolution to the length of the microseismic wave.

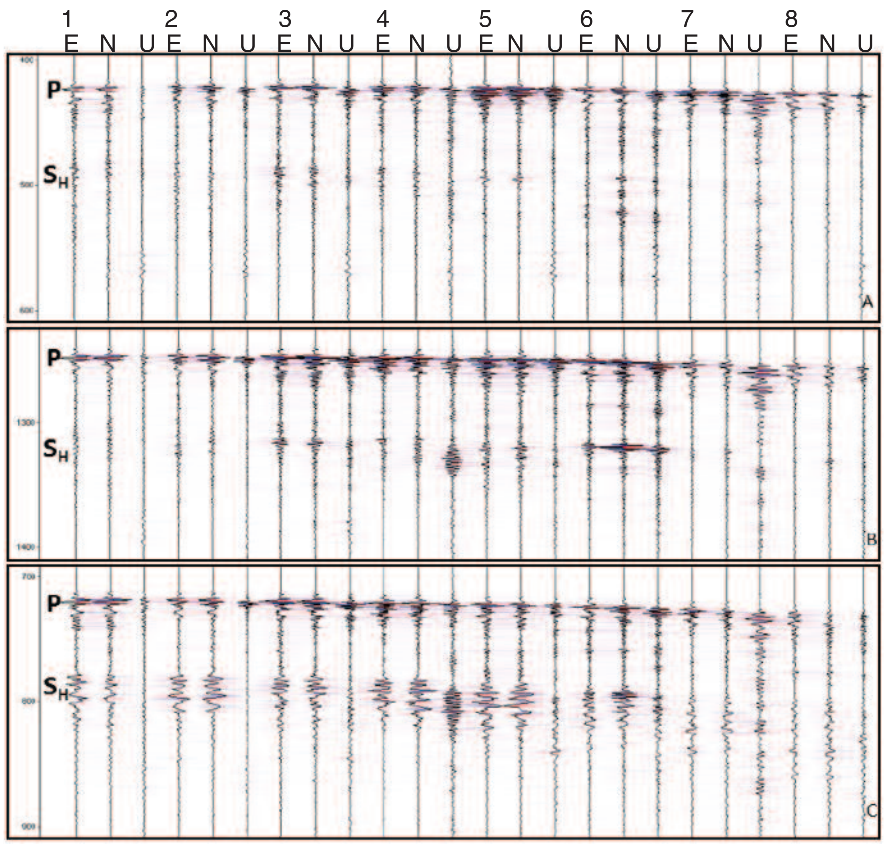
Because the frequency of the signal from microseismic events can be as high as 600-1,000 hertz, the resolution can reach down to two-four meters.

Microseismic data recorded down hole have the additional advantage of being three components. Therefore, they provide information about the full wave field: P wave, S wave and head wave.

Although this article only introduces a P-wave tomographic result, the method potentially can be applied to all phases. If a shear wave splitting phenomenon is visible on the waveform, shear wave splitting tomography can provide an image of reservoir anisotropy.

FIGURE 2

Waveforms of 10H Stage 2 Perforation Shots (A=Perf 1, B=Perf 2, C=Perf 3)



The three components of each receiver are grouped, and are rotated to the east (E), north (N) and up (U) directions. Vertical axis is time in milliseconds from an arbitrary origin time. The scale of the waveforms is adjusted for best visualization purposes.

Experiment Setup

Our cross-well tomographic experiment took place in the Marcellus Shale of southwestern Pennsylvania. The experiment consisted of five laterals: 2H, 3H, 4H, 10H and 11H (Figure 1). Eight downhole, three-component geophones were placed in 2H, while 3H, 4H, 10H and 11H were fractured. The completion was a zipper frac using a standard plug-and-perforate process. The geophones were moved three times to get closer to the stimulated stages.

To a first approximation, ray paths for the perforation shots are straight lines because the source/receiver pairs are in the same plane (Figure 1). There were 74 perforation shots recovered from the microseismic record, the majority of which came from wells closer to the observation well (2H).

The waveforms of perforation shots consist mainly of P wave and SH waves (i.e., shear waves polarized on the horizontal plane). Only the SH wave is visible because of the radiation pattern of the perforation and the effect of horizontal bedding on the transmission of the shear wave (Figure 2).

P wave arrival is impulsive, which is beneficial to accurately picking the arrival time. On some of the traces, the SH waveforms get reduced dramatically because of fluid-filled open fractures along the ray path.

Inversion Using Perforation

The observer's log has the time of the

FIGURE 3A **FIGURE 3B**

Illustration of Checkerboard Test

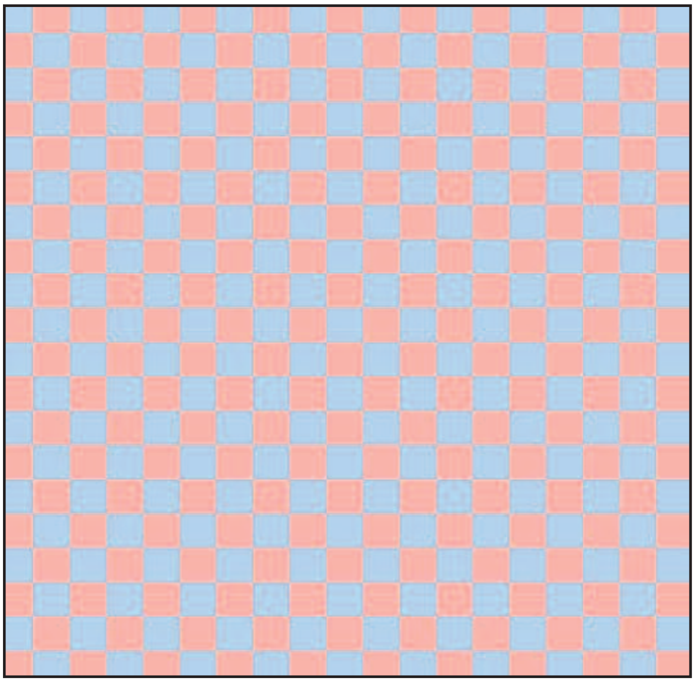


Figure 3A is the input velocity model with the same grid size as the velocity model using real data. Figure 3B is the inverted model using the same ray paths seen in Figure 1. Pink color represents a lower velocity (6.5 feet per millisecond). Light blue represents a higher velocity (7.5 ft/ms). Gray represents the intermediate velocity (7.0 ft/ms).

perforation shots accurate to one second. This is the primary drawback affecting the study's data quality. Since there is no exact record of the origin time of the perforation shots, we assume an average velocity to calculate the origin time initially, based on the length of the ray path.

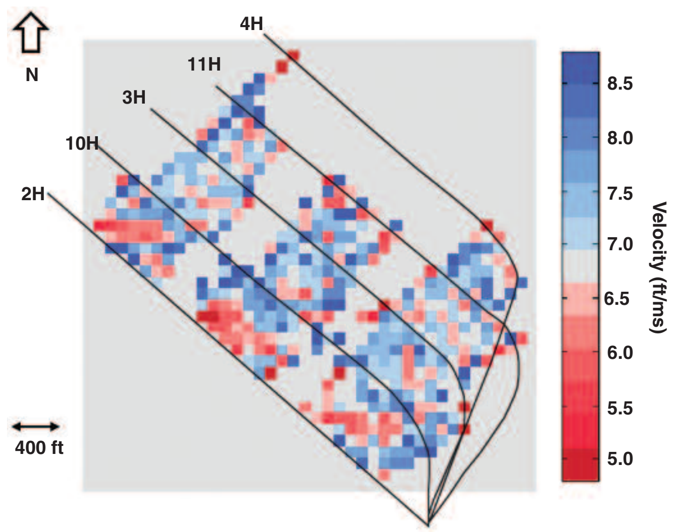
However, to perform a tomographic inversion, we really need the accuracy of timing to one millisecond. If this technique is worthy, microseismic service companies should record perforation times using electromagnetic signals recorded from perforation gun fire lines.

After calculating the origin time, we use the derived travel time to compute the velocity inversion. The reservoir is "discretized" into a 40 by 40 grid. The size of each grid is about 200 feet square. The length of ray path in each grid is calculated using a straight line corrected by the depth difference between the source and receiver. Two inversion methods are used to get the velocity structure of the Marcellus Shale reservoir: linear damped least square inversion (LDLSI) and nonlinear iterative inversion (NLII).

Both methods are used routinely in seismology studies. LDLSI is used commonly in solving linear problems, while NLII is used to solve nonlinear problems. LDLSI calculates the inverse of velocity (called slowness) by adding a damping

FIGURE 4A **FIGURE 4B**

Map View of Velocity Structure Inverted Using Tomography Method



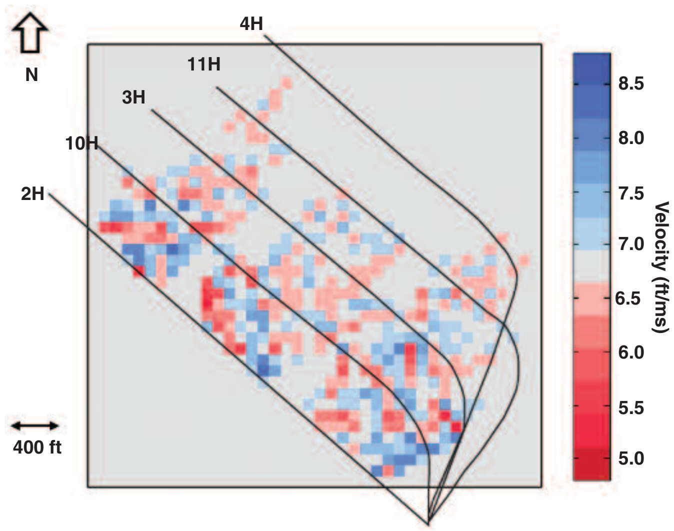


Figure 4A is inverted using linear damped least square inversion. Figure 4B is inverted using nonlinear iterative inversion. Well trajectories are overlain on the velocity structure.

coefficient to suppress the noise in the data. NLII starts from an average velocity model and updates the model iteratively until it fits the observations.

To gain an intuitive feeling for the resolution of our tomographic method, a checkerboard test is needed. A checkerboard test uses a known velocity model with sharp contrasts as an input following the same ray paths to test the resolution of the ray geometry (Figure 3A).

The results shown in Figure 3B are inverted with NLII, using the same grid and ray path geometry as in the real data. Block size used in the checkerboard test is four times (400 by 400 feet) the size of the grid in the real inversion. The checkerboard model is recovered fully at the locations where rays cross each other (Figure 1).

On the other hand, the model is not resolved in the regions with little or no ray coverage. Therefore, during interpretation, we should focus on the region with better resolution, or more crossing ray paths, to draw convincing conclusions. Checkerboard testing using LDLSI shows similar results.

Interpreting Velocity Structure

The LDLSI and NLII methods show similar patterns of reservoir velocity (Figures 4A and 4B). The average velocity of the reservoir is 6.8 feet per millisecond (ft/msec). This is lower than the typical P-wave velocity measured from sonic logs (7.8 ft/msec) or laboratory measurements (9.8 ft/msec) in organic-rich shale.

One possible reason why the inverted velocity is lower is the dispersion effect caused by anelasticity of the organic-rich shale. The frequency of log and lab measurements is much higher than that of perf signals.

Another possible reason is that the initial velocity model used to calculate the origin time was low. To get an accurate absolute velocity structure, the perforation origin time should be recorded accurately. The inverted velocity ranges from 5.5 ft/msec to 8.0 ft/msec. This is a large range of variation. Some of the extreme values may be caused by the noise. The NLII result shows less variation because it started from an average model.

The two images clearly demonstrate the level of heterogeneity in the reservoir. Since this analysis reflects post-stimulation results, the images reflect the combination of the original heterogeneity of the shale and that caused by the stimulation process.

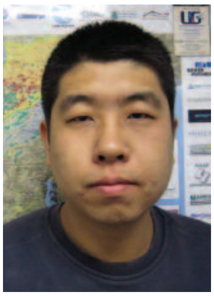
The most interesting result from this inversion is that the region near the 2H well is slower than other parts of the reservoir. In both Figures 4A and 4B, the low velocity region starts from the middle line between wells 2H and 10H, and goes along the path of well 2H. This phenomenon is clearer in Figure 4A, but still is visible on Figure 4B.

Considering that 2H is the only well that is not stimulated during this experiment, this result identifies a very interesting effect of stimulation: The hydraulic fracturing increases P-wave velocity in the reservoir near the stimulated region. These high-velocity regions are part of the stimulated reservoir volume.

The mechanisms behind the increase of velocity within the SRV could include:

- Elastic compression of the shale matrix by high pressure fracture fluid;
- Replacing a compressible fluid (i.e., gas) in natural fractures with an incompressible fluid (i.e., water); or
- Cooling of the reservoir by frac fluid.

Among these mechanisms, the horizontal stress caused by pumping millions of gallons of water into the reservoir will increase the stiffness of the rock, thus allowing higher velocities. If the presence of incompressible water played a greater role in the direct transmission of P-waves, a partially saturated shale should cause greater dispersion and, hence, slower velocities. ❐



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