Factors affecting velocity model calibration for microseismic event location

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Summary

When locating microseismic events using conventional travel time picking methods, one or more velocity models can be required. The models are optimized using available calibration data, such as perforation shots, stringshots, or ball seat events. When a model cannot correctly predict calibration data locations, a different model is introduced. It is argued that introducing fluid into the reservoir leads to changes in pore pressure; these changes lead to velocity changes, which require an adjustment to the velocity model. This study shows that there is little to no difference in travel times between waves traveling though fractured and virgin rock. Other parameters, such as inaccuracy in well positions, deviation surveys, or sonic logs might have more significant effect on the modeling. A proper velocity model calibration with an application of anisotropy parameters where appropriate can significantly reduce the number of models necessary.

Microseismic events are widely used to estimate hydraulic fracture networks. Several approaches exist to locate microseismic events, the most common of which are travel time picking and applying a velocity model to estimate the distance and depth of the events. Sonic logs are used to build an initial model, then an optimization is necessary based on the available calibration data.

Both isotropic and anisotropic models are used. When an isotropic model is used, more changes to the initial model are necessary because of factors, such as the accuracy of sonic logs, deviation survey errors, wellhead position errors, and accounting for anisotropy. Applying an anisotropic model can decrease the number of required models as a result of accounting for different angles of incidences. Depending on the area of interest, horizontal transverse isotropy (HTI), vertical transverse isotropy (VTI), and orthorhombic models should be used.

When good quality calibration data are available, anisotropy is accounted for, treatment and observation wells geometries are accurate, and the number of models needed can be significantly reduced. Ideally, only one model is necessary to predict the locations of calibration data.

Theory / Method / Workflow

A starting velocity model is typically designed based on sonic logs from the observation well. If these logs are not available, logs from a nearby vertical or horizontal well are used. When using reference well logs, they must be adjusted in accordance with the lithology in the observation well to predict travel time arrivals with greater accuracy. An initial model rarely locates calibration data correctly; consequently, an optimization is needed. Because sonic logging is a near-borehole measurement, estimated formation acoustic velocity is highly influenced by borehole conditions, position of the tool in the hole, velocity gradients in the rock, density inhomogeneity, bed boundaries, tilting beds, stress conditions, and intrinsic rock anisotropy In a formation with a lesser degree of anisotropy, the difference between velocities in the initial and calibrated models is usually less than 5%. Otherwise, discrepancies between the initial sonic log-based model and the calibrated seismic model of ± 10% are not uncommon. Compressional velocities usually require less change than shear wave velocities.

In addition to potential errors in sonic logs, the accuracy of the deviation surveys of treatment and observation wells can affect the true calibration data locations and geophone positions; consequently, an adjustment to the starting model will be necessary. The estimated lateral error in the deviation surveys can reach 100 to 200 ft at 10,000 ft MD (Williamson and Wilson 2000).

In a case of a shallow toolstring and using an isotropic model, more models are usually necessary to account for different angles of ray paths. A different model is applied at a distance where the previous model is not working, which is confirmed by locating the calibration data. Accounting for anisotropy can help to reduce the number of models necessary. VTI is common in tight oil and gas formations as a result of horizontal layering (Vernik and Liu, 1997). A VTI model is usually sufficient to accurately predict travel time arrivals at different reservoir depths.

Another factor supporting the use of multiple models is the expected changes of physical properties of the geological medium caused by introducing fracturing fluid into the formation (Crowley et al. 2015). Krasnova et al. (2013) showed changes in frequency content for perforation shots separated from the toolstring by hydraulic fracturing and those that generated seismic waves traveling through virgin rock.

This study shows that changes in travel time arrivals are insignificant to justify introducing a different model for the fractured area.

Results, Observations, Conclusions

Examples

Two different datasets were used for this study to show repeatability of the results, despite the differences in geology. Both datasets were recorded using vertical straddling arrays and the same geophone types. The differences between the datasets were a wide fracture network in the oil-bearing dataset and planar fractures in the gas-bearing dataset.

Dataset 1: Oil-Bearing Formation

Dataset 1 consists of perforation shots fired in a horizontal treatment well and recorded using a vertical straddling toolstring. The formation of interest is an oil reservoir. The observation well was positioned at equal distances from both toe and heel of the treatment well (Figure 1). Fractures grew perpendicular to the wellbore trajectory, and the event cloud width remained within the vicinity of the perforations. Consequently, perforation shots for each subsequent stage generated seismic waves that traveled through virgin rock until the treated stage was directly across from the observation well. At that point, the perforation shots generated waves traveling through fractured rock. The perforation shots recorded for toe (virgin) and heel (fractured) areas were separated into two subsets, and the P and S travel time separation for each tool was calculated.

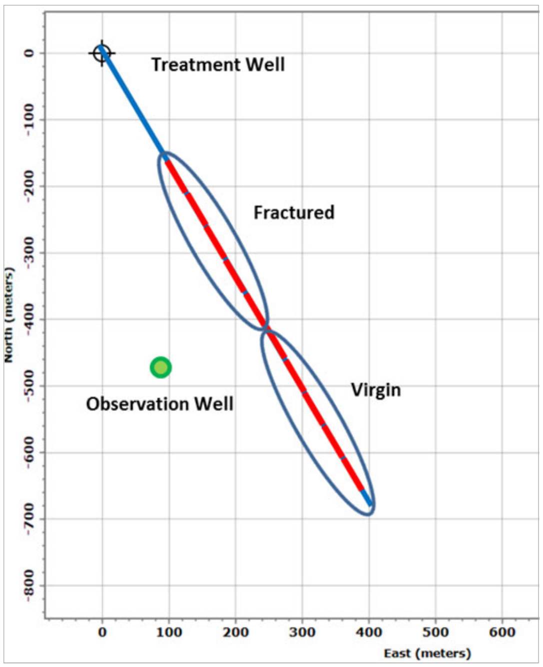

Figure 1: Dataset 1 setup, map view. Two subsets of data are shown.

A dependence of observed travel time differences between P and S waves and the actual distance to the perforations was calculated for each tool. The depths of the perforations were obtained from the wireline company after they were shot to help ensure their locational accuracy.

Figure 2 shows P-S separation vs. distance for Tool 11, which was positioned at the same depth as the landing depth of the treatment well. This tool should have observed the largest change in the travel times because the majority of events occurred at this depth (Figure 3). As shown in Figure 2, there is a slight difference in P-S separation for waves that traveled through fractured rock vs. virgin rock. At the same time, there is practically no difference between P-S separation for waves that traveled through fractured rock vs. virgin rock for tool 15 (Figure 4, second from the bottom) where very few events were observed. To reach any of the tools, a wave would have traveled through fractured rock at some point; however, the greater the distance between the tools and the fractured area, the smaller the percentage of the waves' travel distance affected by treatment fluid placed in the rock. As shown in Figure 2, the greatest change in P-S arrivals is observed on the closest perforation shots that are at the distances between 150 and 250 m from the toolstring, whereas distant perforation shots show no difference.

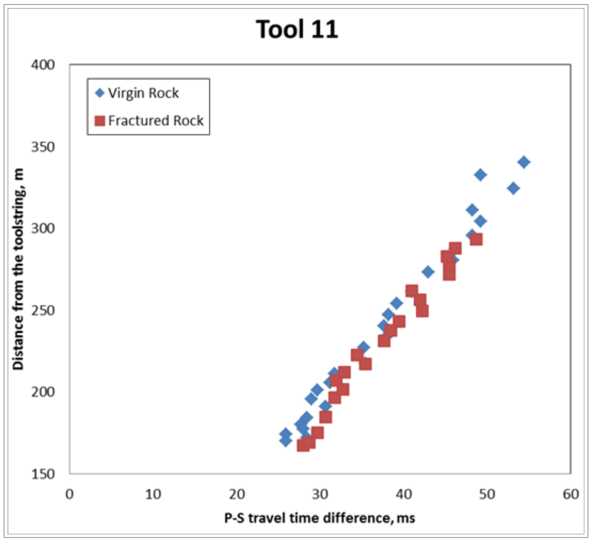

Figure 2: Dataset 1: P-S separation vs. distance from the toolstring to the locations of the fired perforations for the tool at the same TVD as the treatment well.

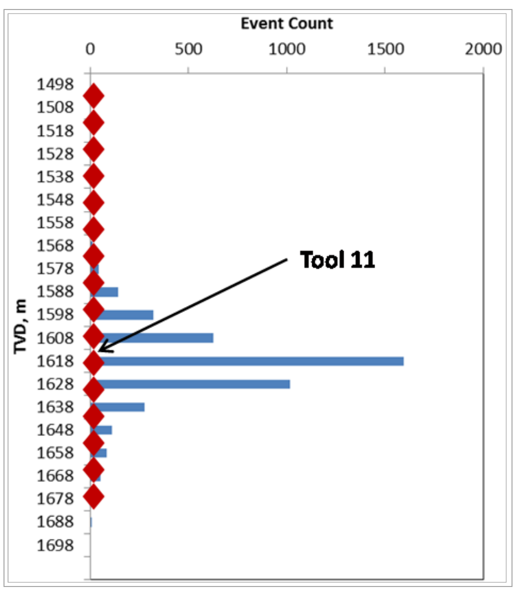

Figure 3: Dataset 1: event density by depth overlaid with geophone positions (red diamonds).

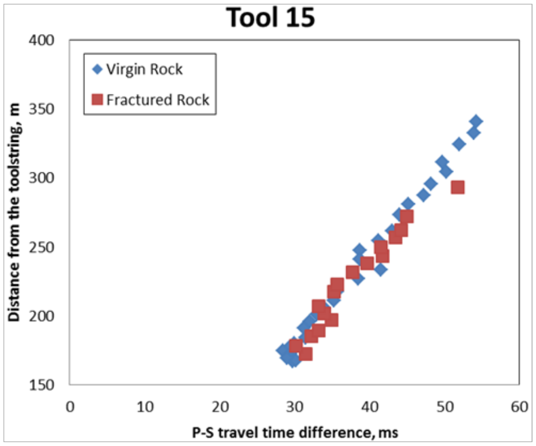

Figure 4 Dataset 1: P-S separation vs. distance from the toolstring to the locations of the fired perforations for the tool second from the bottom of the array.

The perforation shots from both subsets were used for a VTI velocity model calibration. One model was obtained to locate all perforation shots at their place of origin with overall travel time residuals of less than 2 ms. Average travel times residuals for P and S waves were calculated for each tool, and were combined for all tools, as shown in Figures 5, 6, and 7. There is no apparent increase in the residuals for waves traveling through fractured rock, with P wave residuals being slightly greater on the bottom of the toolstring. Figure 8 shows the distance between located perforation shots and the actual perforation locations. Fractured rock shows a slight increase in locational error: from 12m of maximum difference between perforation locations and the located perfshots for virgin rock vs 15m for the fractured one.

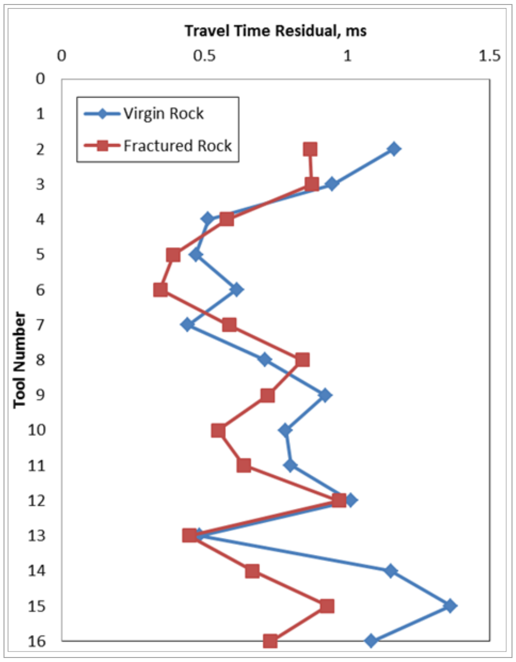

Figure 5: Dataset 1: P wave residual for Sensors 1 through 15 looking through virgin and fractured rock.

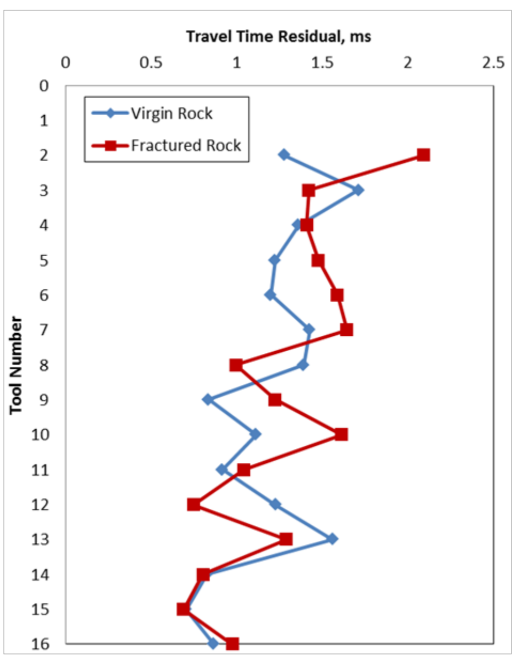

Figure 6: Dataset 1: S wave residual for Sensors 1 through 15 looking through virgin and fractured rock.

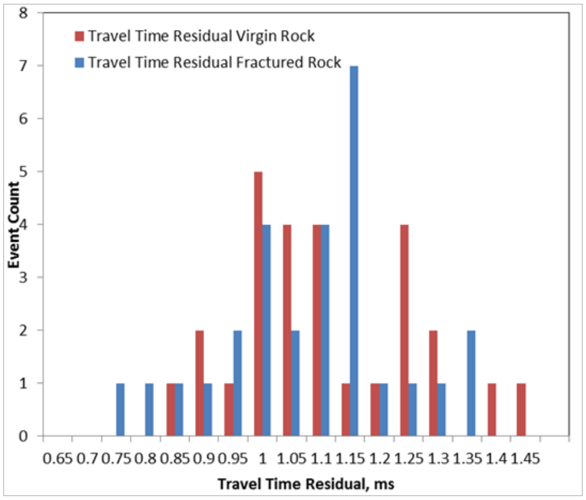

Figure 7: Dataset 1: Combined travel time residuals for all tools for both P and S.

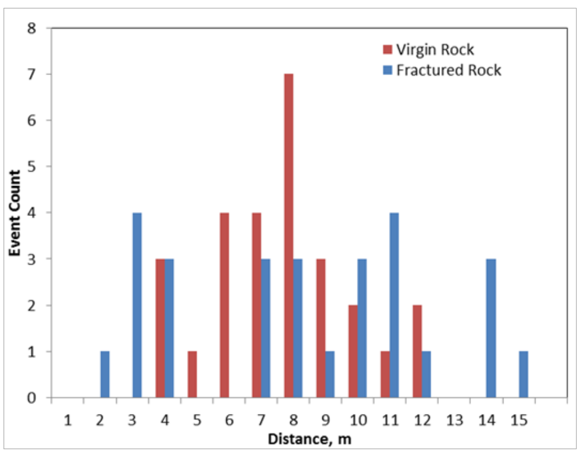

Figure 8: Dataset 1: Distance between perforation shots locations and the actual perforations positions.

Dataset 2: Gas Bearing Formation

Dataset 2 was recorded in a gas formation. The well geometries were similar to the first dataset; the observation well was vertical and positioned at equal distances from both toe and heel of the treatment well (Figure 1). Perforation shots waves at the toe stages were considered as traveling through virgin rock, whereas heel
stages generated waves were considered as traveling through fractured rock. A straddling toolstring was used to record microseismic events. P-S separation on each sensor was calculated and plotted against the actual distance to the perforations. Figure 9 shows P-S separation for the tool located at the same depth as the wellbore landing depth. There is no apparent difference for waves traveling through virgin or fractured rock. The remaining tools showed similar behavior. There are two outliers; it is suspected that the depths provided for

these shots were incorrect and that they originate instead at the same depth because their P-S separation is similar.

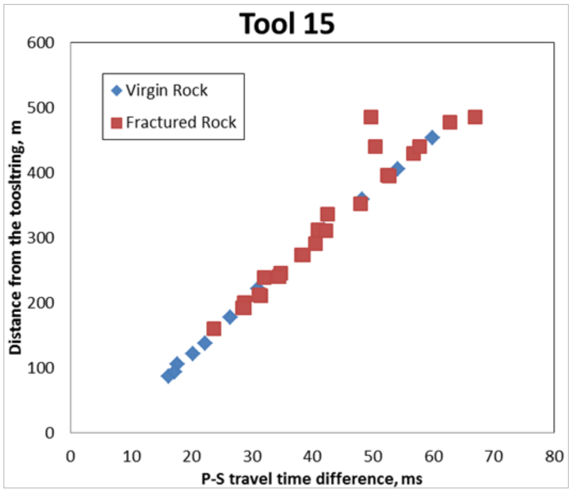

Figure 9: Dataset 2: P-S difference vs. distance for tool positioned at the same depth as the landing wellbore depth where the majority of events were recorded.

Conclusion

This study suggests that the injection of treatment fluid into a formation does not significantly affect velocity values. Travel time separation between compressional and shear waves were not affected by the fluid. As a result, one velocity model was sufficient to locate all perforation shots, with the errors as small as 2 m. The largest error of 15 m was observed on only one event. Other factors, such as errors in the deviation surveys, sonic logs, or poor velocity model optimization, likely have more effect on the number of models necessary per project.