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Microseismic Monitoring, Processing and Interpretation of Hydraulic Fracture Treatments: Geological Considerations

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Summary

Over the last decade, microseismic monitoring of hydraulic fracture stimulations has increased significantly. Geoscientists, engineers, and decision makers realize the value this measurement brings in terms of reservoir understanding. It is not uncommon for mapped event locations, associated source parameters, and attributes derived from surface, shallow wellbores, and deep wellbores (vertical, deviated, or horizontal) to be taken at face value without proper understanding as to how they have been obtained. This can lead to misunderstandings, poor accounting for measurement limitations, and, most importantly, misinterpretations. Geologic considerations are important at every step of the microseismic monitoring workflow. Ignoring the geology and associated rock properties can potentially lead to inadequate monitoring configurations, inconsistent processing approaches, misleading interpretations, and ultimately suboptimal understanding and planning of stimulation treatments.

Introduction: Integrated Hydraulic Fracturing Workflow

Integrated workflows for unconventional reservoirs are commonly used to develop and evaluate completion strategies including staging, perforation plans, stimulation design, and well spacing (e.g., Hryb et al., 2014; Figure 1). These workflows typically start with a thorough analysis and characterization of the geology, structure, and rock properties of the reservoir and surrounding formations (Figure 1). Proper characterization of the natural fracture network and the strata and structural history of a region of interest are key in properly modeling the hydraulic fracture stimulation geometry and controls, as well as the conductivity distribution (Miller et al., 2013; Hryb et al., 2014). The information used may include 3D seismic surveys, acoustic impedance and other seismic-derived property volumes, microseismic surveys, sonic logs, rock cores, burial history, and petrophysical measurements from well logs. Natural fracture patterns and the regional stress field are also mapped and then used to develop and calibrate fracture propagation models. Decision makers use these models with production simulation models to predict how different completion strategies will perform and determine the optimal stimulation plan.

Real-time microseismic monitoring of hydraulic fracture stimulations is a key tool in the rapid evaluation of stimulation performance; as such, its use in planning and managing reservoir development has increased significantly. Microseismic event locations, source characteristics, and attributes provide immediate estimates of fracturing extent that can be quickly compared with the completion plan and used to determine the extent of fracturing of the target formation, location of proppant, effective stimulated volume, and understimulated sections of the reservoir. Microseismic event locations can also help avoid geohazards during stimulation such as faults, karst, and aquifers. Furthermore, microseismic monitoring results are used to update and calibrate the geologic and structural models used in planning completions (Figure 1). Event locations and source parameters (fracture plane orientation and slip), which provide a direct measurement of the local stress field, can be used to develop and calibrate discrete fracture network (DFN) models. Microseismic event locations and attributes may also be integrated and compared with treatment pressure records, proppant concentration, and injection rate to better evaluate a completion plan (Downie et al., 2015).

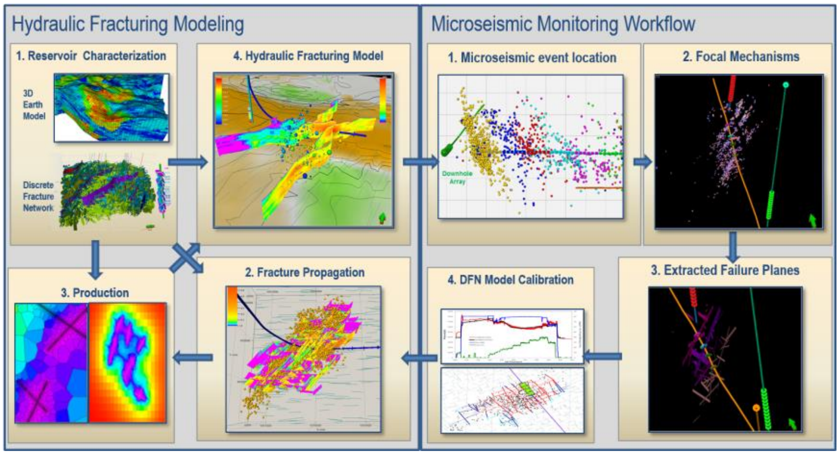

Figure 1. (Left panel) Hydraulic fracturing models developed through the integration of (1) geologic and structural reservoir characterization models, (2) fracture propagation models, and (3) production models are used in evaluating different unconventional completion strategies. (Right panel) Real-time microseismic monitoring is important in evaluating the performance of hydraulic fracturing stimulations and in providing information for calibrating and developing improved fracture models for future stimulations.

Errors in microseismic event locations and their attributes can alter the interpretation of stimulation effectiveness and fracture growth patterns. Without a proper understanding of how microseismic event locations and attributes are determined, misinterpretations can occur and limit the usefulness of microseismic monitoring results in completions and stimulation models and planning. Understanding of the survey design biases, the quality of the velocity model used, and the quality of the seismic data are key factors in the detection and location of microseismic events, as well as calculation of their source parameters and quality attributes. A variety of geologic and geophysical information is necessary to determine an accurate velocity model and establish an optimal survey design that properly accounts for the source characteristics, earth propagation, and noise model (Le Calvez et al., 2015). Furthermore, proper integration of multiscale, multidomain measurements and observations into workflows aids the planning and monitoring of hydraulic fracturing treatments and can increase the value of production.

Microseismic Monitoring Workflow and Examples

Each step of the microseismic monitoring workflow and important geologic considerations for each step are described as follows.

1. *Velocity model construction:* The initial velocity model is typically constructed from blocked and smoothed sonic logs with P-sonic, S-sonic, density, and attenuation measurements from the monitor well or a nearby well. Proper conditioning of the logs and correlation of formation boundaries to tie the logs from the sonic well to the formation structure in the region of interest is an essential step in generating a velocity model that accurately reflects the local geology. Well ties can be made using formation tops, gamma ray logs, and formation surfaces interpreted from seismic and well logs. Surfaces also are useful to correctly orient the velocity model to account for formation structures around the target zone. For example, Figure 2 illustrates a comparison of two different velocity models generated from identical logs, but with different blocking and smoothing and with and without dip. On average, across all perforations the dipped velocity model with finer blocking and smoothing provided a 64% improvement in event locations over the nondipped, coarsely blocked model.

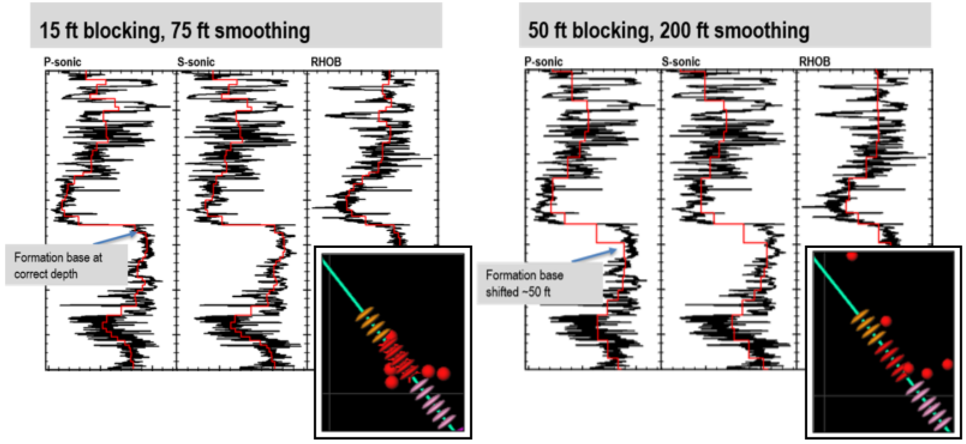

Figure 2. Comparison of velocity models (red curves) derived from borehole sonic logs (black curves) with different blocking and smoothing applied. The model with finer blocking (15 ft) and a shorter smoothing length (75 ft) has interface boundaries at the correct depth, whereas the coarser blocking (50 ft) and smoothing (200 ft) results in formation boundaries located at the incorrect depth. Insets show located perf events (red circles) in relation to their actual location (red discs), processed with the dipped 15-ft-blocked velocity model (left) and the flat 50-ft-blocked velocity model (right).

2. *Survey design:* The survey design is used to determine the optimal array location for detecting and locating microseismic events by taking into account models of the source, earth propagation, and noise (Le Calvez et al., 2015). The source model includes characteristics of the source mechanism, location, amplitude, and radiation pattern. The earth propagation model accounts for the geologic structure, velocities, and intrinsic attenuation of the formations through which the signal propagates to the monitor array (Le Calvez et al., 2015). The source characteristics depend on the local geology and state of stress. Therefore, knowing the orientation of principal geological features such as fractures and faults can help avoid biases due to monitoring station positions and in the interpretation. The initial velocity model constructed from sonic logs serves as a representation of the earth propagation model.
3. *Sensor orientation:* Poor signal quality due to high levels of noise, amplitude loss due to distance from the monitoring array, and poor tool coupling can increase the uncertainty in determining the event azimuth. Because poor polarization information can result in incorrectly locating events, proper characterizing the earth and noise models and determining the optimal performance of different array configurations are key steps in mitigating poor data quality and optimizing event locations.
4. *Velocity model calibration:* Isotropic models that do not account for the high vertical anisotropy in shales and unconventional gas reservoirs can result in incorrectly located events (Figure 3). Calibration of the isotropic velocity model is done by measuring perforation shots or string shots from a known location(s), which is typically the treatment well. Time picks of the P, Sh, and Sv arrivals, as well as the origin time, are used to invert for the Thomsen anisotropy parameters (ε, γ, δ) (Thomsen, 1986). Sources of error may include the vertical and horizontal anisotropy, lateral variations in velocities and anisotropy, errors in deviation surveys and “known” locations of perforations and arrays, dip of formations, and errors in the sonic logs used to build the initial isotropic velocity model (Woerpel, 2010). For example, incorrect velocities on the order of 5% can cause mislocation distances on the order of tens of meters (Maxwell et al., 2010). Rock physics logs may have estimates of ε, γ, and δ that can give an estimate of the geologically reasonable anisotropy parameters for the velocity model calibration, but they cannot be substituted for velocity model calibration due to differences in the source-receiver path of microseismic and borehole measurements. Integrating several measurements at various scales (e.g., core, log, crosswell, vertical seismic profile [VSP], 3D VSP and walkaway/walkaround, and surface seismic) to build a “correct” 3D velocity model in terms of structure, P-, S_h- and S_v-waves would be ideal.
5. *Event detection, location, and calculation of location uncertainty and source parameters:* The main factors that can affect event detection and location, as well as attributes and source parameter

values, include the accuracy of the earth model (represented by the calibrated velocity model) and microseismic data quality. Proper construction and calibration of the velocity model to account for variations in velocities, vertical and horizontal anisotropy, and dip of formations reduces the uncertainty of event locations and minimizes mislocation artifacts. Location artifacts, as illustrated in Figure 3, can alter the interpretation result regarding the simulated volume and fracture patterns. Seismic data quality affects time pickability, the amplitude of the microseismic signal recorded at an array, and the ability of accurate directionality information (hodograms) to be measured, thus, affecting the ability to locate microseismic events correctly.

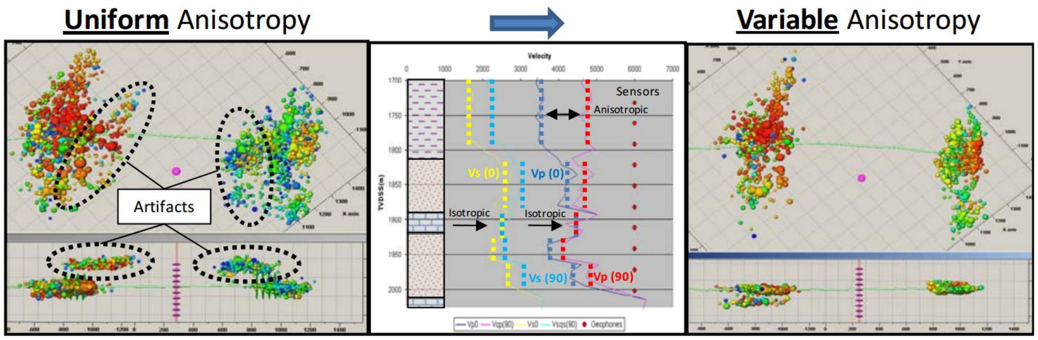

Figure 3. The effect of constant vertical anisotropy (left) and variable vertical anisotropy (right) on mapped event locations (modified from Maxwell et al., 2010). The geologic model (center) indicates complexity in the layered geometry. The left side shows events located in a diffuse double cloud that is generated when the vertical complexity is ignored and a constant vertical anisotropy is applied. By using a variable vertical anisotropy, the event clouds are more compact and place at the correct depth (right).

6. *Integration and Interpretation:* The following are examples of integration of microseismic with multiscale, multidomain data:
   - Use of seismic rock property volumes, microseismic, and borehole measurements to establish their relationship to regions of effective stimulation (Miller et al., 2013; Refunjol et al., 2012; Primiero et al., 2013; Leiceaga et al., 2013).
   - Integration of microseismic events with wellbore images that identify natural fracture patterns and density, drilling-induced fractures, and formation mineralogy to help understand the geological conditions that affect completion quality and the impact of mineralogy, in situ stress, and fracture patterns on hydraulic fracture system geometry (Miller et al., 2013).
   - Integration of microseismic with seismically derived 3D rock property volumes to improve 3D characterizations in the formations of interest that can affect fracture propagation patterns (Primiero et al., 2013; Refunjol et al., 2012).
   - Combination of borehole, 3D rock property volumes, and microseismic data to aid the probabilistic evaluation of hydrocarbon production capacity (Leiceaga et al., 2013).

Conclusions

Accurate characterization of the geology and structure of a region plays a key role in hydraulic fracture monitoring and in stimulation plans. Poorly located microseismic events and low-quality attributes can potentially lead to misleading interpretations of estimated stimulation volumes and adversely affect the reservoir and fracture models used for production simulations. Proper integration of information about the geology and associated rock properties of a region of interest is essential to accurately locate microseismic events and calculate their source characteristics and attributes. Integration of microseismic results and regional rock properties can play a critical role in understanding—and optimizing—stimulation treatments.