Completions and reservoir engineering applications of microseismic data

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Introduction

Evaluating hydraulic fracturing treatments by employing passive seismic monitoring technology has become an accepted industry practice and standard in the last decade foremost for unconventional resources. Due to microseismic monitoring it is now understood that the fracture created during hydraulic stimulation greatly deviates from the planar bi-wing textbook example that has been an accepted image in the industry for a long time. In heavily fractured ultra-low permeability shales, the fracture network is highly complex; it is therefore imperative to accurately image this network in order to understand the response of the formation to the treatment as well as the effect of the treatment on production in order to optimize the wellbore completion and the stimulation treatment (Neuhaus et al., 2012).

Neuhaus et al. (2012) showcased a multidisciplinary approach to microseismic monitoring by performing an integrated analysis of data acquired during the stimulation of five wellpads completed in the Marcellus Shale. The case study provided a detailed investigation of the microseismic data in conjunction with other data, such as well logs and cores, reservoir properties, and information on regional and local geology. It determined how factors related to the geology of the reservoir and to the stimulation approach impacted the microseismic results. These observations were then used to relate changes in the microseismicity, changes in the geology, and changes in the stimulation method to changes in production in order to optimize field development and the completion design of the wellbores. Recommendations regarding the wellbore azimuth and completion strategy were obtained from the integrated analysis as well as an optimum wellbore spacing. Distinguishing between the total stimulated rock volume (SRV) where microseismic activity was observed and the part of the SRV that contains proppant filled fractures and will therefore be productive in the long term allowed for sophisticated wellbore spacing determination which was performed for one of the pads in the study area. The distribution of proppant filled fractures can also be used to illustrate the containment of proppant within the DFN to evaluate the optimal wellbore spacing, stage length and spacing, as well as landing depth of the wellbore. The microseismic data set used in this case study was acquired with a permanently-installed near-surface array consisting of 101 stations. The wide azimuth, large-aperture, and high fold geometry of the deployed surface array allowed for a consistent resolution under the 18 square mile footprint of the array. Furthermore, the rich sampling of the seismic wavefront provides a high-confidence estimate of event magnitude as well as the failure mechanism for every event which is the crucial input for Discrete Fracture Network (DFN) modelling from microseismic used to evaluate the distribution of proppant and quantify propped half-lengths for the individual treatments (Duncan and Williams-Stroud, 2009; Neuhaus et al., 2012; McKenna and Toohey, 2013). Analyzing the microseismic data in a spatio-temporal sense then enables the reservoir engineer to obtain a system permeability, quantifying the ability to deliver hydrocarbons into the hydraulic fracture system and through the fracture network back to the wellbore, and ultimately predicting production. Overall, the workflow outlined in this extended abstract closes the loop between microseismic data, treatment optimization, and wellbore productivity.

Discrete Fracture Network Modelling

From the final microseismic pointsets obtained for the treatment a DFN is modeled onto the microseismic events in two steps. The underlying assumption is that every event is representative of a fracture, which can be modeled and is centered on the event. Inverting for the focal mechanism of each microseismic event gives the strike and dip of the failure plane for the events. The geometry of each individual failure plane is then determined through a methodology incorporating the magnitude of an event, the rigidity of the rock that is being treated, the injected fluid volumes, and the fluid efficiency (McKenna and Toohey, 2013).

Data acquired with a surface or near-surface array monitoring array allows us to obtain focal mechanisms (Seibel et al., 2010; Baig and Urbancic, 2010). Through a least-squares, full moment tensor inversion of the peak amplitudes of particle velocity from manually picked P-wave arrivals on the vertical component, the seismic wave front is inverted to obtain a focal mechanism for an event. Assuming a point source, the moment tensor representing the source mechanism can be inverted from a point source relationship between observed displacements on the vertical component and the moment tensor component. While it is possible to use both P- and S-waves for the inversion, only amplitudes of direct P-waves on vertical receiver components are used for the material discussed herein as they provide a reliable result independent of the often poorly constrained S-wave velocity model (Williams-Stroud et al., 2008; Williams-Stroud et al., 2012; Williams-Stroud et al., 2012; Zhou et al., 2013). From the moment magnitude, the seismic moment can be calculated, which is proportional to the area of the failure plane, the displacement along the plane, and the rigidity of the rock. Since the displacement is not directly modeled, it is initially estimated as a function of the seismic moment by assuming a constant stress drop. From the seismic moment and the rock rigidity, the area of the fracture plane can then be calculated. Relating the aperture of the fracture to the square root of its length, and assuming an aspect ratio of length to height of 2:1, the geometry of the three-dimensional fracture is obtained and a fracture volume can be computed. Assuming that the total detected seismicity is directly related to the injected fluid volume and that the change in volume is completely accommodated by the seismic failure, minus leak-off, if such information is available, the calculated fracture volume should equal the injected fluid volume. Since the seismic energy that was recorded during a treatment and subsequently located as discrete events is usually only a fraction of the total emitted energy, the two volumes described above rarely match. In order to account for any undetected microseismic event population, such as tensile failure emitting quickly attenuating low frequency signal, or microseismic events with a signal below the detection threshold, a scaling factor is introduced which is applied to every stage (McGarr, 1976; Kanamori, 1977; Bohnhoff et al., 2010; McKenna and Toohey, 2013).

Wellbore Azimuth and Completion Strategy

Since two joint sets are found in the Marcellus, it might be desirable to reactivate both with hydraulic fracture stimulation. Despite the fact that, due to the current stress-state, flow in the J1 direction might be favored over flow in the J2 direction, increasing the complexity of the created fracture network enhances the overall permeability. Reactivation of J1 joints seems to be predominantly linked to dip-slip failure, while failure along J2 joints appears to yield more strike-slip events. The wellbore orientation employed on the study wells seems to have reactivated both joint sets potentially creating additional permeability in the J2 direction.

The percentage of strike-slip events on a well-by-well basis varies from 15% to 44% with an average of 24%. A correlation between percentage of strike-slip events and normalized gas production was observed. This signifies the importance of adding complexity to improve drainage even in the case of stress-dependent permeability where flow in one direction is preferred over the other. In order for strike-slip failure to occur, a different local stress regime is required than for the occurrence of dip-slip failure. While regional geology will influence the way the additional pressure the reservoir is subjected to during the treatment is being transmitted along the tortuous flowpaths of the rock, stimulation approach also seems to play a role. The sequence in which the stages are being treated appears to change the percentage of strike-slip events. Treating one well at a time from toe to heel results in a lower relative amount of strike-slip events than treating a wellpad in a zippered fashion, completing a respective stage on all wells moving from one side to the other (Neuhaus et al., 2012).

It was also found that increasing or decreasing the stage length by 20 ft, resulting in either saving one stage or adding one over the total length of a wellbore, produced similar results compared to the original completion design. Given the natural fracture density observed in outcrops of the Marcellus shale, an additional five feet between each of the five perforation clusters (due to eliminating one stage) should only minutely change the hydraulic fracture network. Especially since J1 fractures are so dense and closely spaced that virtually no difference should be observed while costs could be reduced as well as the environmental footprint of the treatment. If one hydraulic fracturing stage per well could therefore be eliminated, the potential savings for an entire well pad can approach a seven figure dollar amount (Neuhaus et al., 2013).

Proppant Distribution and Wellbore Spacing

From the complete DFN modelled onto the microseismic events, a subset DFN is generated including only fractures centered on events in the target zone which is then adjusted for event location uncertainty to evaluate proppant placement and estimate the productive part of the total stimulated rock volume. Events in the hydrocarbon-bearing target zone are most likely to represent rock failure that contributes to production in the long term. Estimating the propped half-length is performed by filling the subset DFN with proppant from the wellbore outward on a stage by stage basis. The packing density of the proppant is variable and can be adjusted based on the specific gravity of the proppant and available hydraulic fracture models. The distance of fractures to the wellbore is measured as the radial distance between the center of the stage and the event the fractures are centered on. Proppant filling is constrained by tortuosity of the flow path by allowing only 50% of the proppant to populate fractures intersecting the prevalent failure plane azimuth at angles of more than 45°. The fracture volume inside the respective stage DFN is filled with proppant until all proppant that was pumped is accounted for. Estimated propped half-lengths are then determined by breaking up the proppant filled fracture distances into a perpendicular horizontal, a parallel horizontal, and a perpendicular vertical component with respect to the corresponding stage center (McKenna and Toohey, 2013). The statistical properties (average, median, standard deviation) of the distribution of fracture distances can be used to illustrate the containment of proppant within the DFN to evaluate the optimal wellbore spacing, stage length and spacing, as well as landing depth of the wellbore if incorporated with gamma ray and stress vertical stress profile information, as seen in Figure 1.

In order to calculate the total Stimulated Rock Volume (SRV), a three-dimensional grid is applied to the total DFN. Every grid-cell containing a non-zero fracture property is included in the SRV. The total SRV is dependent on the size of the model cells and can be adjusted based on known reservoir flow properties. It represents the total rock volume that was affected by the treatment. In order to discern between the part of the SRV that is assumed to be drained over the lifetime of the wellbore and the remaining, unproductive part of the SRV, the same workflow is applied to the proppant filled DFN described above. The subset SRV that is calculated from the part of the DFN containing proppant then represents the productive SRV that is expected to contribute to production in the long term. Based on the DFN and the SRV, the permeability tensor can be calculated for the rock volume containing microseismic activity (Oda, 1985). The full tensor is calculated from the total number of fractures in an individual grid cell, based on the fracture orientations and sizes. The permeability that is derived is the fracture permeability for a dual-porosity dual-permeability reservoir model. It should be noted that it is not representative or in any way indicative of the matrix permeability. In addition to the fracture permeability calculated from the DFN, a system or bulk permeability can be obtained from an evaluation of the spatio-temporal dynamics of the microseismic events and the apparent system diffusivity (Shapiro and Dinske, 2008; Grechka et al., 2010; Angus and Verdon, 2013).

The Productive Stimulated Rock Volume workflow was performed on a three-well pad in the study area, herein named Well 1, Well 2, and Well 3, as illustrated in Figure 2 for Well 1. The average propped half-length for all wells is 320 feet from the wellbore. Using this propped half-length and the Productive Stimulated Rock Volume, we estimate the percentage of the rock volume that has been propped and likely contributes to production in the long term to be roughly 33% for all three wells. That means that about one third of the entire rock volume where microseismic activity was observed contains proppant filled fractures.

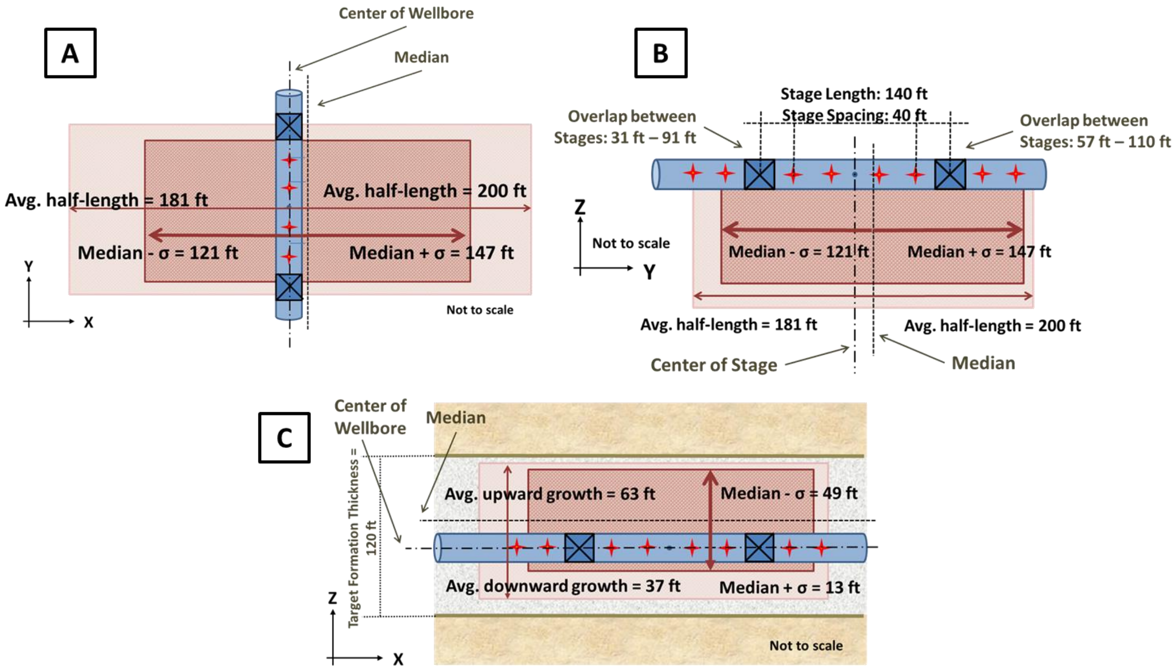

Figure 1 *Perpendicular horizontal (A), parallel horizontal (B) and perpendicular vertical (C) propped fracture distance distribution with example values. Statistical properties (average, median, standard deviation) are used to evaluate the proppant distribution inside the DFN in order to optimize wellbore spacing (A), stage spacing and length through quantifying longitudinal coverage along the wellbore and overlap between stages (B), and landing depth through quantifying upward and downward growth of propped fractures.*

Permeability

A system or bulk permeability can be obtained from an evaluation of the dynamics of the microseismic events in time and space and the apparent system diffusivity. Various models have been developed to describe the spatio-temporal evolution of microseismicity. Non-linear diffusion pore-pressure triggering is probably the most studied model and assumes that microseismicity is hydraulically induced and characterized in terms of a low frequency pore-pressure relaxation mechanism. Microseismicity can also be explained by linear diffusion if coupled to linear poroelastic deformation rather than the non-linear fluid diffusion mechanisms in the theory explained above. The driving force for the linear diffusion model is a front of effective stress perturbations. The actual seismic trigger is the propagation of Coulomb Yielding Stress perturbations along the diffusion front caused by seepage forces which are body forces generated by the fluid pressure gradient. A third model is available incorporating the stress state of the reservoir and the fault friction coefficient of the features that can be stimulated and failed, representing geomechanical reservoir characteristics. The Mohr-Coulomb failure criterion for shear failure is used to solve for the pore pressure required for shear failure as a function of geomechanical properties (Shapiro and Dinske, 2008; Grechka et al., 2010; Angus and Verdon, 2013; Rozhko, 2010; Hosseini et al., 2013).

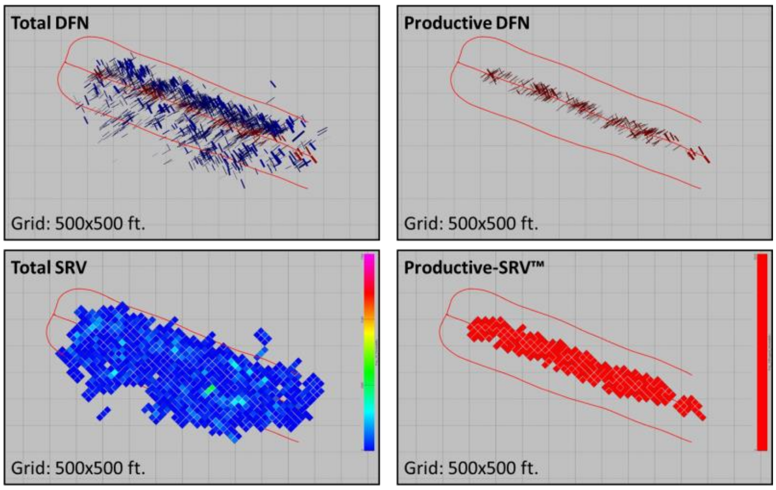

Figure 2 *Productive Stimulated Rock Volume for Well 1. The total DFN can be seen in blue in the upper left corner. The proppant filled portion of the total DFN can be seen in red in the upper right corner. From the total DFN the total SRV can be determined as illustrated in blue in the bottom left corner. The productive portion of the SRV due to proppant filled fractures is shown in red in the bottom right corner.*

Conclusions

- The chosen wellbore azimuth reactivates both fracture sets in the Marcellus yielding in a more complex and potentially more permeable fracture network.
- Zipper-frac'ing leads to more secondary fracture set reactivation in the study area increasing fracture network complexity.
- Varying stage length shows the highest potential in cost savings by eliminating only one stage per well.
- Evaluating proppant placement in the calibrated DFN allows for discerning between the part of the SRV that contributes to production in the long term, and the part of the reservoir that was affected by the treatment but may not be hydraulically connected over a longer period of time directly impacting wellbore spacing decisions, completion design, and landing depth.
- Analyzing the occurrence of microseismic events in the space-time domain can provide a system permeability characterizing fluid flow into and out of the combination of induced fractures, reactivated natural fractures, and matrix.