Reservoir Simulation

How Well Did You Complete?

A Marcellus Shale Completions Optimisation Case Study

The article explains an integrated analysis of hydraulic fracturing treatments in the Marcellus Shale that was conducted to investigate the relationship between reservoir geology, wellbore completion, stimulation design, and microseismic data to evaluate the correlation between hydrocarbon production and microseismic results relative to changes in geology and the stimulation approach.

Over the last decade, microseismic monitoring has become an accepted industry practice and, some might say, a standard when frac'ing in unconventional reservoirs. Contrary to the bi-wing type textbook example that's been recognised in the industry, fractures that are created in shale plays during hydraulic stimulation are quite different. In reality, the fracture network created in unconventional plays is extremely complex and accurate imaging is necessary to understand the formation and enable completions optimisation and maximise asset value and recoverable reserves.

Microseismic data can be used to model a Discrete Fracture Network (DFN) that serves as an important input for reservoir simulation. The model allows the total rock volume affected by the treatment to be calculated. This can be taken a step further by placing proppant in the DFN to help identify the part of the Stimulated Rock Volume (SRV) that likely contains proppant and should therefore be productive. This type of analysis using microseismic data allows operators to understand where the proppant went and what proportion of the reservoir is actually productive to help determine ideal well spacing, stage length, and alternate treatment options.

Currently, three core monitoring methods are commercially available to record microseismic data: downhole, surface, and near-surface. Though single-well downhole monitoring is sufficient in some cases, the broad areal coverage of surface and near-surface monitoring usually provides more detailed information. Surface monitoring makes it possible to determine the way in which the formation is breaking (strike, dip, rake), which is essential to build the desired, highly accurate DFN (Williams-Stroud 2008). As a result, some operators are choosing to implement a hybrid monitoring technique that combines downhole and surface to achieve an even higher resolution and accuracy.

After a monitoring method has been selected and the proper data has been acquired, the DFN is built in two steps. First, the strike and dip of the failure plane is determined for each individual event. Then, the geometry of the failure plane is determined by incorporating the magnitude of each event, as well as the calculated rigidity of the rock and the injected fluid volumes. Once the DFN is completed, the SRV can be determined. In addition, the proportion of the SRV that contains proppant, and is therefore productive in the long term, can be estimated.

Calculating how much of the fracture volume will be productive begins by estimating the propped half-length. Estimation of 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 hydraulic fracture simulation. For each stage, the fracture volume inside the DFN is filled with proppant until all of the proppant that was pumped is accounted for. The estimated propped half-length is determined by looking at the statistical distribution of proppant filled fractures around the wellbore. This accounts for the fact that the fractures are centered on the microseismic events while honoring the distribution of fracture sizes for a given stage.

In order to calculate how much production can be expected of the stimulated rock volume, a three-dimensional grid is applied to the proppant-filled DFN. Every grid-cell containing a non-zero fracture property that was filled with proppant is included in the productive area of treatment. This yields a rock volume that is expected to contribute to production in the long term as illustrated in Figure 1 on next page.

Based on the DFN and the SRV, the permeability tensor can be calculated for the rock volume containing microseismic activity (Oda, 1985). The permeability 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. This evaluation can help to characterise the reservoir and estimate the results of hydraulic fracturing by calculating permeability on a stage-by-stage basis.

Case Study

An integrated analysis of hydraulic fracturing treatments in the Marcellus Shale was conducted to investigate the relationship between reservoir geology, wellbore completion, stimulation design, and microseismic data. These findings were then used to evaluate the correlation between hydrocarbon production

> **Fracture network created in unconventional plays is extremely complex and accurate imaging is necessary to understand the formation and enable completions optimisation and maximise asset value and recoverable reserves.**

and microseismic results relative to changes in geology and the stimulation approach. The observed variability in the microseismic response was used to derive regional trends and optimise field development. Initial production was compared to reservoir and engineering parameters, such as treatment pressures, sequence of treatments (toe-to-heel vs. zipper-frac), net pressures, and stage spacing, to determine if the variability in the microseismic results is due to engineering differences or to spatially-varying reservoir properties.

The microseismic data set was acquired with a permanently-installed near-surface array consisting of 101 geophones, as seen below in Figure 2 on next page.

Two fracture sets are present in the Marcellus shale. J1 fractures are oriented northeast to southwest and were formed as natural hydraulic fractures during the Alleghenian Orogeny (Engelder et al., 2009). J2 fractures (oriented northwest to southeast) were formed during hydrocarbon generation and cross-cut the older J1 fracture set (Duncan and Williams-Stroud, 2009).

Ideally, a horizontal well attempting to produce from the Marcellus Shale should activate the J1 fracture set to exploit the high permeability of these fractures and activate the J2 fractures to connect parallel J1 fractures. If the J2 fracture sets are stimulated, those fractures will inevitably intersect the J1 fracture set allowing production from those fractures. Operators drilling in the Marcellus Shale have found that orienting well-bores to activate both the J1 and J2 fracture sets yield the highest production. Additionally, in this case, zipper-frac'ing was found to better activate both fracture sets and further improve production.

To analyse different treatment attributes, a base DFN model was created and varied on five dimensions (flow rate, treatment pressure, stage duration, stage length, number of perforations, and perforation cluster spacing) with the goal of refining completions designs for optimal economic return.

In this case, stage length had the greatest economic impact. Given the natural fracture density observed in the outcrops of the Marcellus shale, it was found

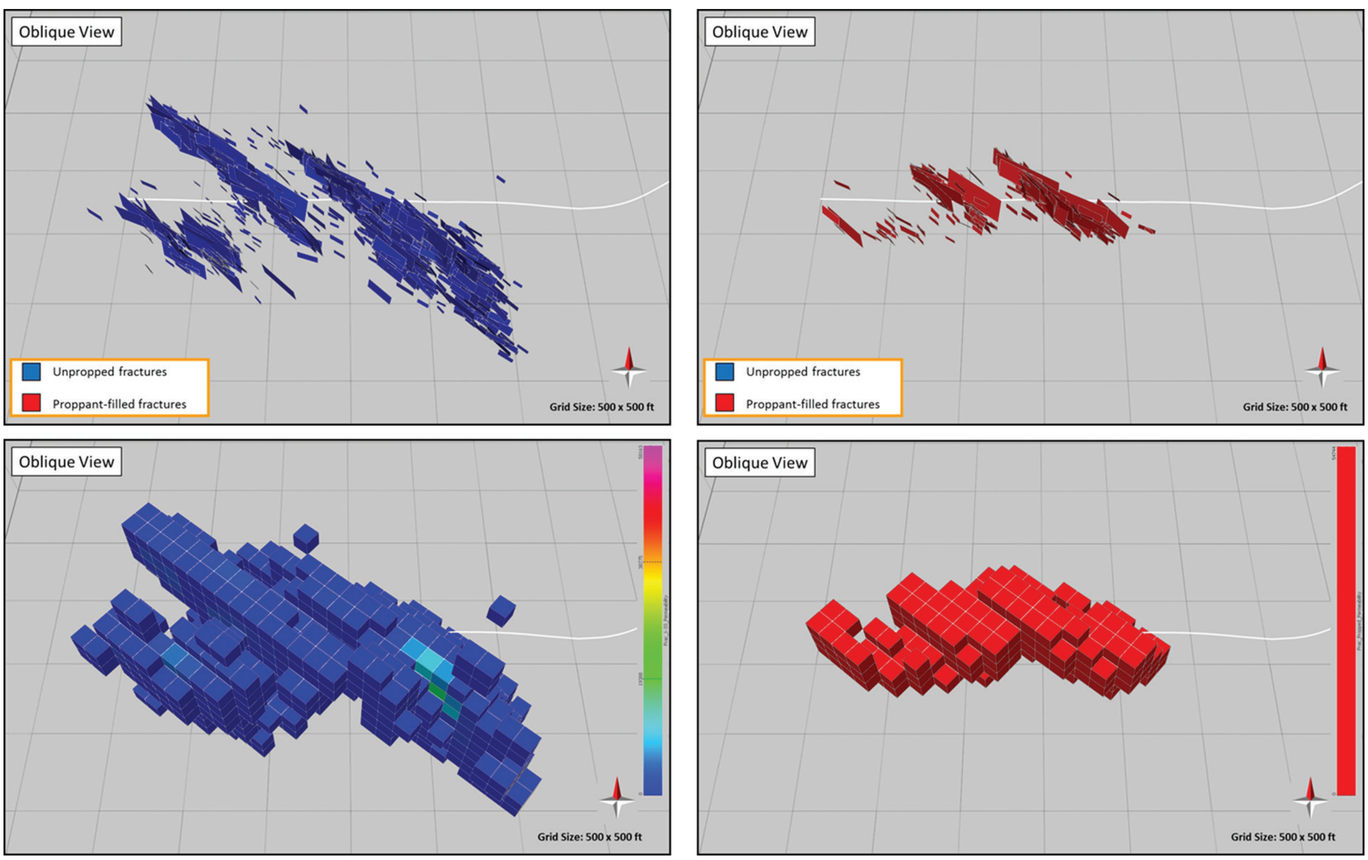

Figure 1: Total productive rock volume. The total DFN can be seen in blue in the upper left corner. The proppant filled portion of the total DFN can be seen in red in the upper right corner. From the total DFN the total SRV can be determined as illustrated in blue in the bottom left corner. The productive portion of the SRV due to proppant filled fractures is shown in red in the bottom right corner.

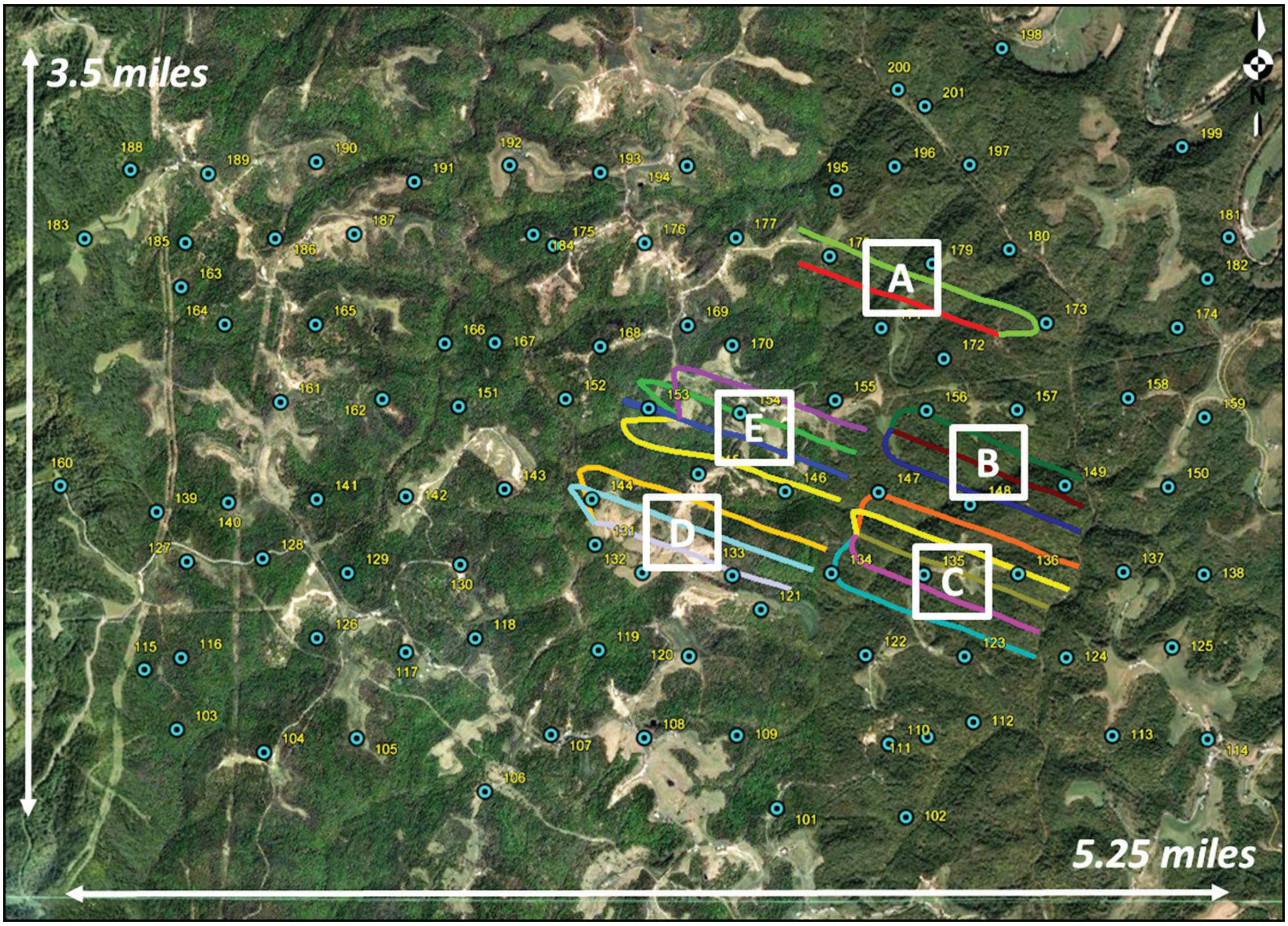

Figure 2: Map view of surface microseismic monitoring array. Recording stations can be seen as turquoise circles. Well pads are named with letters.

that an additional 5 feet between each of the five perforation clusters would only minutely change the hydraulic fracture network. This finding could permit the elimination of one stage per well, effectively saving the operator time, energy, and costs. Applied across the entire well pad, the potential savings could have approached a seven figure dollar amount. Additionally, zipper-frac'ing was found to better activate both the J1 and J2 fracture sets to improve production. To further optimise field development in the Marcellus, calculation of how much of the reservoir was actually propped during treatment can be used to provide information for well spacing and ensure that hydrocarbons are not being left behind.

These new advances in technology integrating geophysical and engineering results can clearly demonstrate real value to oil and gas companies operating in unconventional shale plays. The ability to understand what proportion of the stimulated rock volume is actually productive allows operators to improve production and recoverable reserves and lower costs by optimising well spacing and determining ideal stage lengths. ●

References

1) Williams-Stroud S., "Using Microseismic Events to Constrain Fracture Network Models and Implications for Generating Fracture Flow Properties for Reservoir Simulation" SPE 119895, SPE Shale Gas Production Conference, Fort Worth, TX, USA, November 16-18, 2008

2) Oda M., "Permeability tensor for discontinuous rock masses", Geotechnique, Vol. 35 (4), pp. 483-495, 1985

3) Engelder T., Lash G.G., Uzcategui R.S., "Joint sets that enhance production from Middle and Devonian gas shales of the Appalachian Basin", AAPG Bulletin, Vol. 93, pp. 857-889, July 2009

4) Williams-Stroud S., Neuhaus C.W., Telker C., Remington C., Barker W.B., Neshyba G., Blair K., "Temporal Evolution of Stress States from Hydraulic Fracturing Source Mechanisms in the Marcellus Shale" SPE 162786, SPE Canadian Unconventional Resources Conference, Calgary, AB, Canada, October 30 – November 1, 2012

Carl Neuhaus
Product Champion - Completions Evaluation
MicroSeismic Inc
Email: cneuhaus@microseismic.com