



Real-Time Microseismic Monitoring of Simultaneous Hydraulic Fracturing Treatments in Adjacent Horizontal Wells in the Woodford Shale

Robert C. Downie*

Schlumberger, Oklahoma City, Oklahoma, U.S.A.

downie1@oklahoma-city.oilfield.slb.com

and

Joël H. Le Calvez

Schlumberger, Addison, Texas, U.S.A

and

Ken Kerrihard

Continental Resources Inc., Enid, Oklahoma, U.S.A.

Introduction

The commercial success of horizontal wells drilled in shale-gas reservoirs depends upon the ability to initiate multiple parallel fractures, and/or the presence of complex networks of natural fractures that are connected by induced hydraulic fractures. Production modeling of horizontal well completions shows that recovery might be improved if the distance between parallel hydraulic fractures can be reduced.^{1,2}

Simultaneous fracturing of two or more adjacent and parallel horizontal wells has been tested in the Barnett Shale to create hydraulic fracture networks more closely spaced than can be achieved from a single wellbore. Positive results in comparison to wells completed individually were attributed to increased fracture complexity resulting from the interaction of hydraulic fractures initiated in parallel wells.^{3,4} Pressure response while fracturing and radioactive tracer surveys were the primary evaluation tools used. The two previously mentioned references contained an implicit assumption that rock mechanical properties were more or less constant along the length of the horizontal lateral. Evaluation of fracture stimulation treatments in the Barnett Shale that incorporated advanced open-hole logging measurements such as image logs, and borehole-based microseismic monitoring, showed that fracture geometry can be influenced greatly by changes in rock properties along the length of the lateral.⁵ The implications of such heterogeneity cannot be ignored when transferring technology from the Barnett Shale to other gas-shale reservoirs.

In this paper, we present the results of a microseismic monitoring campaign undertaken as part of a drilling and completion program in the Woodford Shale of south-central Oklahoma that included both single-well and simultaneous fracturing treatments. Two project areas, designated Eastern and Western were selected for live microseismic monitoring during fracturing operations. The project began with a single-well completion in May, 2007 in the Eastern project area. In April, 2008, a four-well simultaneous fracturing treatment was performed in the Western project area. The Eastern project area was finished in June, 2008 and included re-stimulation of the first well completed in May, 2007, a two-well simultaneous fracturing treatment, and the completion of a single well. All treatments were monitored with borehole-based

microseismic measurement. Real-time processing and display of microseismic event locations was provided to the engineering team responsible for the fracture stimulation treatments at the fracturing location.

Woodford Shale Reservoir Characteristics

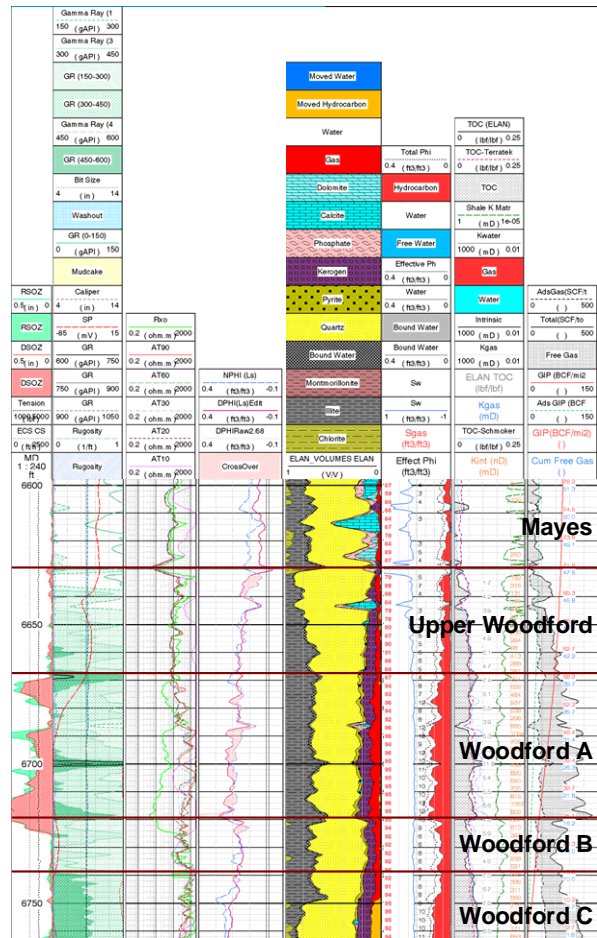
The Woodford Shale is an organic-rich, siliceous shale composed of 48 - 74% quartz, 3 - 10% feldspar, 7 - 25% illite clay, 0 - 10% pyrite, 0 - 5% carbonate, and 7 - 16% kerogen based on log and core analyses. The Woodford in this study area has been sub-divided into 4 units, Upper Woodford, Woodford A, Woodford B, and Woodford C. The Upper Woodford frequently has the highest clay content, while the Woodford A and C intervals have the highest silica content along with the highest effective porosity. The Woodford B has lower apparent porosity than the Woodford A and C. Laminations of siliceous and clay-rich layers can be seen in outcrops and have been observed in core samples. Natural fractures are often present in the siliceous layers but do not extend through the clay-rich layers.



Photograph of Woodford Shale outcrop



Core sample showing calcite-filled natural fractures

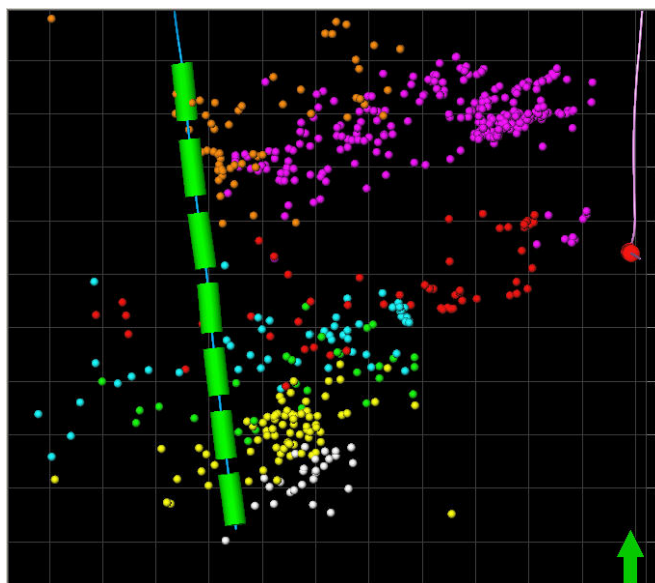


Woodford Shale Type Log

The Woodford Shale has been subjected to periods of tectonic activity that has produced fault systems within the reservoir. In some cases, fault systems with different strikes have been identified. This produces uncertainty about the azimuth of induced hydraulic fractures. Horizontal wells in the Woodford Shale are drilled so that several transverse fracturing stages can be pumped during the completion. Fractures that initiate at an angle to the wellbore might be subject to excessively high near-wellbore pressures which can place limitations on the pumping rate and maximum proppant concentration.

Microseismic Monitoring, Well A1, Eastern Project Area

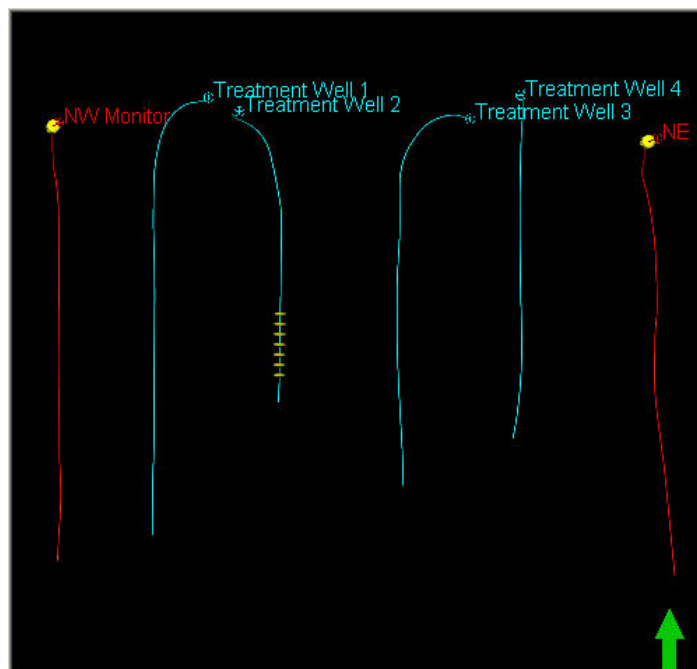
Microseismic monitoring with live processing of event locations during stimulation treatments allows engineers to assess and modify stimulation designs and make appropriate changes while the stimulation treatment is in progress. A field test of real-time on-site microseismic processing was performed during the completion of the first of the project wells. One of the many observations resulting from this monitoring was that microseismic activity could be detected in the Woodford Shale at distances up to 3,500 feet (1,000 m) from the monitoring well. Sections of the lateral that did not appear to have been adequately stimulated were identified. In addition, some fractures had much greater lengths than others based on microseismic activity.



A1 microseismic data

Microseismic Monitoring, Four Well Simultaneous Fracturing Treatment, Western Project Area

The next large-scale fracturing project with microseismic monitoring was a four-well simultaneous fracturing treatment located approximately 3 miles (5 km) west of the Eastern project area. The design of this treatment called for maximization of interaction between fracture networks from parallel wellbores by aligning the perforations for each stage along the primary fracture azimuth. Interpretation of surface seismic data showed that faults with two distinct strikes were present within the project area. It was expected that the fractures would align with one of the two strike directions. The first trend was generally east to west, while a second trend oriented approximately northeast was also present. The most desirable trend from an operational point was east to west since that would require fewer pumping stages to complete all four wells. Microseismic monitoring from two wells was proposed to identify the azimuth of the fractures and select the appropriate perforated intervals for simultaneous pumping operations.



Western project area site layout

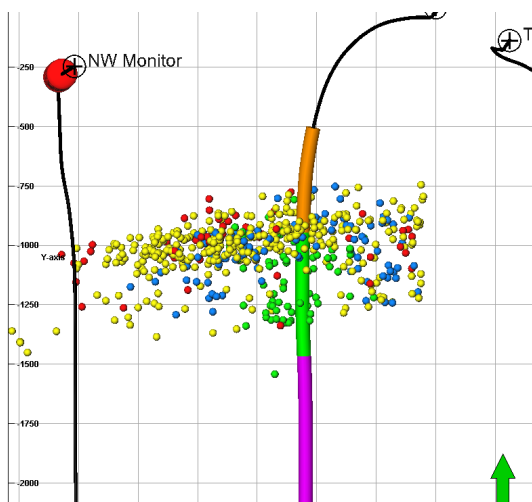
Due to large distances separating the two vertical monitoring wells and the first two fracturing stages, a third microseismic monitoring tool string was placed in the horizontal section of the shortest of the four treatment well laterals. The horizontal tool location was a field test and is the first known example of real-time microseismic processing and display from a horizontal tool array.

Data from the horizontal array indicated that the fractures initiated during the first two pumping stages were oriented generally east to west, although the fracture geometry was complex. During the third stage, when all four wells were being fractured simultaneously, real-time microseismic data indicated that an apparent change in fracture orientation to the northeast might have occurred, along an azimuth of approximately 55°. Further evaluation of the microseismic data recorded at this point of the completion showed that clusters of microseismic events oriented 55° were located where anomalous structural features were present in the surface seismic data. The induced fracture networks remained on an east-to-west azimuth. The decision was made to proceed with the project using the east to west fracture orientation. Microseismic data displayed during the fourth stage confirmed that the correct interpretation had been made.

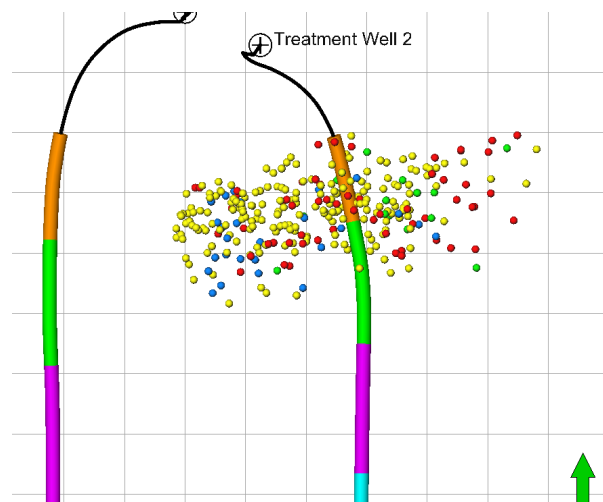
Two distinct fracture geometries appeared to be present within the treatment area. Most of the stages were interpreted as complex fracture networks with no easily-defined azimuth. Some fractures, however, exhibited a strong orientation along a preferred fracture plane. The same pumping schedule was used for every stage.

Fractures initiated in the two exterior treatment wells diverted away from the location of the interference between competing fracture networks to the opposite side of the lateral. In the case where the fracture had a well-defined azimuth, this resulted in undesirable fracture growth into the two previously-completed horizontal wells. Pressure gauges in those two wells confirmed that fluid from the fracturing treatments was entering both wells. This had a negative effect on production from both of the wells used for monitoring and had been observed on other occasions.

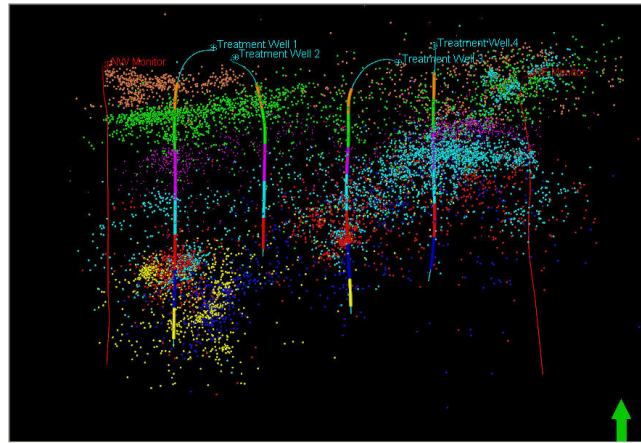
Fractures initiated from the interior wells were confined on both sides, and evidence was found that appeared to confirm the idea that fractures became more complex when the forward front of adjacent fracture treatments came into contact with one another. Excessive height growth after contact was not observed.



Exterior fracture showing lateral extension away from the region where interference between competing fractures is assumed



Interior fracture with increased complexity



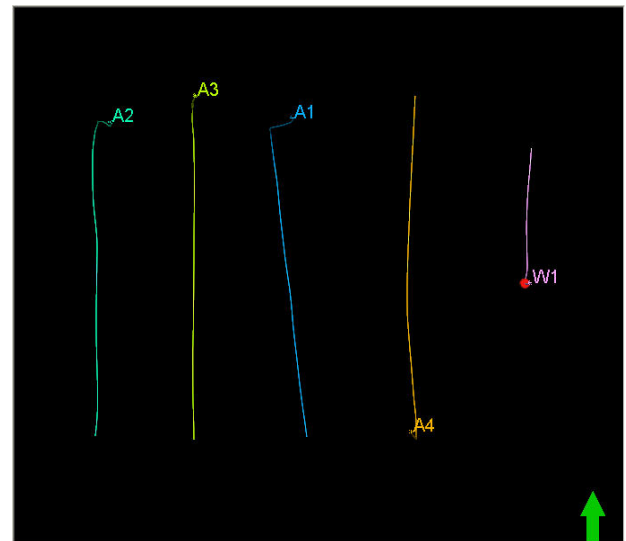
Microseismic data from western project area

Early production results from the four-well simultaneous fracturing treatment were encouraging. Initial rates from the four wells were about 40% higher than had been observed in offset wells. This benefit was short-lived and longer term production from all four wells was slightly lower than the area average. Additionally, the loss of productivity from the two monitoring wells as a result of damage caused by the fracture treatments further reduced total production.

Eastern Project Area Simultaneous Fracture Treatment

Three additional wells were added to the Eastern project area since completion of the A1 well. Two wells, A2 and A3, were drilled west of the A1 well. A third well, A4, was added between the A1 location and an existing well that had been used for microseismic monitoring of the A1 completion. The A2 and A3 wells were scheduled for simultaneous fracturing.

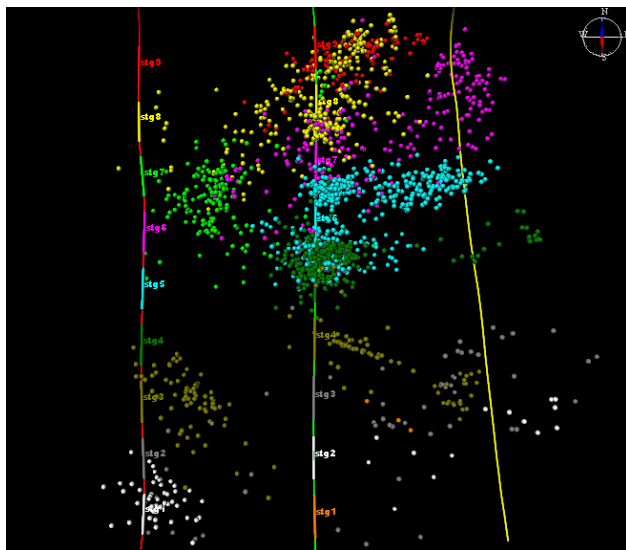
Prior to beginning the simultaneous fracture treatments, the A1 well was re-stimulated. The goal of the re-stimulation was two-fold. First, real-time microseismic monitoring was used to identify the location of fluid injection. The stimulation engineers used the real-time microseismic data to design and pump fracture diversion treatments that sealed off perforations that were under stimulation and change the location of fluid injection to perforations that were in need of additional fracture stimulation. Second, the pressure was left on the A1 well in an attempt to prevent damage to the A1 well from newly-created fractures initiated in the adjacent A3 and A4 wells. The fracturing crews moved to the A2 and A3 immediately after the re-stimulation.



Site layout of eastern project area

Although two monitoring wells were intended to be used during the simultaneous fracture treatment, only one of the two wells was usable due to casing conditions. As a result, relatively few microseismic events were detected during the first four of the nine stages. Additionally, very few events were detected near the A2 lateral and it was not possible to observe the interaction between adjacent fractures that had been seen during the previous project. Pressure interference between adjacent fracture networks was inferred from the location of microseismic activity with respect to the A3 lateral as each stage progressed. The fracture front

from at least five of the nine fracturing stages pumped in the A3 well appeared to make contact with the A1 lateral. Subsequent operations to return the A1 well to production encountered difficulty with proppant flowing into the well and additional expense was incurred cleaning the well with coiled tubing.



A2 and A3 microseismic events

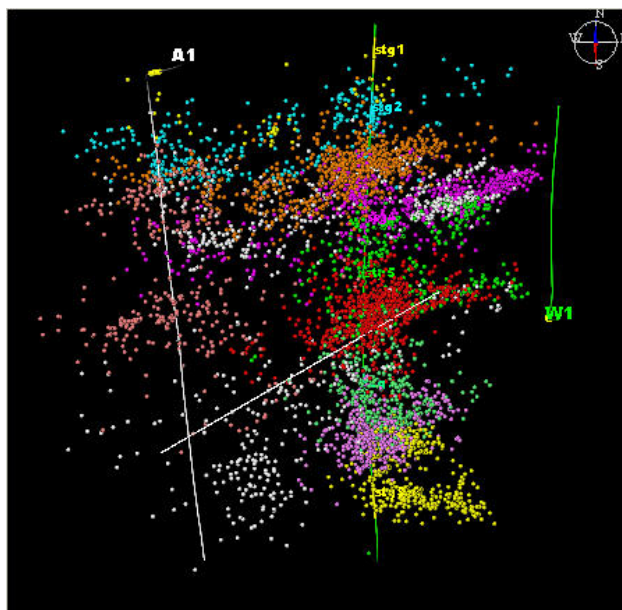
Single-Well Completion of the A4

The A4 well was completed immediately following the simultaneous fracture treatment. Two monitoring wells were used for real-time microseismic measurements. There is a distinct change in the apparent fracture geometry that occurs during the later stages of the treatment. The early stages, two through five, have much longer microseismic lengths compared to stages six through nine. The microseismic event rate during the early stages was low, and increased during the stage. The later stages began with high levels of microseismic activity, which then decreased during the later portions of the pumping schedule. Very few microseismic events were detected during the first stage, in spite of the close proximity to one of the monitoring wells. There is no apparent correlation between observed microseismic activity and fracturing pressure, pumping rate, or proppant concentration. The same pumping schedule was used during all nine stages.

During stage six, the change in fracture geometry was noted during real-time display of the microseismic data. The presence of a fault was suspected, and confirmed when drilling data was reviewed. North of the fault, the microseismic fracture lengths are much longer. Also, north of the fault, the A4 is between drainage areas of both the A1 well, and the W1 monitor well. It could not be determined from the A4 data alone why if the change fracture geometry was caused by stress changes, or the presence of fracture networks from offset wells.

This question was resolved when the A1 microseismic data from 2007 was mapped alongside the A4 events. A similar change in apparent fracture geometry was present in the A1 microseismic data. The apparent fracture length during stages 4 through 7 is much longer than the first three stages. The A1 was drilled in the opposite direction to the A4, so the pattern is the same, that is, the fractures located further north have longer microseismic lengths. Therefore, the position of the fault can be interpreted using the apparent boundaries between differing patterns of microseismic activity. This approach yields an interpreted strike of approximately 60 degrees. This strike also appears to be confirmed by the presence of microseismic activity near the suspected location of the fault during the re-stimulation of the A1 well.

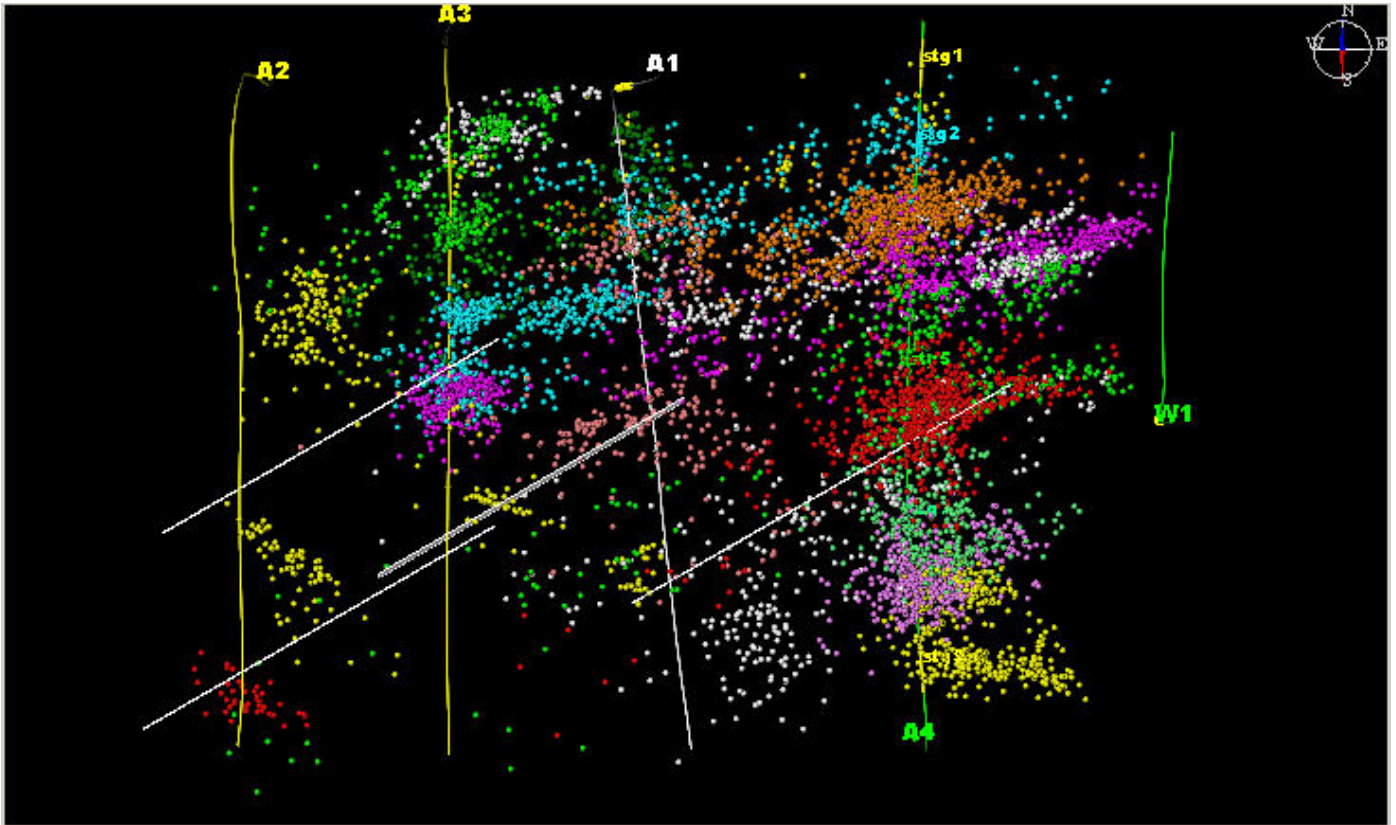
At the time of the A1's completion there were no drainage areas offsetting the A1. Therefore, the change in fracture geometry is largely due to changes in stress anisotropy as a result of structure. However, the influence of drainage from adjacent wells and the presence of fracture networks cannot be ignored. It is also interesting to note that fracture extension from the A4 was great enough in some cases to make contact with offset horizontal laterals. This took place in spite of the absence of interaction from simultaneous fractures. Careful observation during the drilling of the A4 well, or resistivity images recorded during or after drilling might have revealed the presence of fracture networks extending east of the A1 well, as has been observed in other shale-gas reservoirs.⁷



A1 and A4 microseismic data including fault

Suspected faults were identified while drilling the A2 and A3 wells. The location of some of the faults can be correlated using the interpreted strike angle found through the evaluation of the A1 and A4 microseismic data.

During evaluation of the first simultaneous fracturing project, in the western project area, the transition from complex to planar fracture geometry was suspected to be a result of induced stresses from previous fracturing stages.⁶ The influence of structure, and stresses associated with that structure, appear to be the most likely source of this change in fracture geometry. This suggests that seismic interpretation might play a larger role in the design of shale-gas stimulation treatments. There are a number of fracture treatment design options that might be employed when surface seismic and borehole-based microseismic measurements are used during the design and execution of fracturing treatments to control and modify fracture geometry under different stress conditions.



Microseismic data and interpreted faults in the eastern project area

Conclusion

Evaluation of the production histories of wells discussed in this paper appears to show that simultaneous fracturing treatments do not necessarily increase well productivity when compared to conventional completions. Also, where new wells have been drilled in proximity to existing wells there is potential for damage to the completed well by fluids introduced during the stimulation of the new well(s). The benefits of simultaneous fracturing are most apparent when 3 or more wells are stimulated simultaneously. In the western project area, the interior wells produce more gas when normalized for lateral length compared to the exterior wells. In the eastern project area, the A4 well, which was completed without simultaneous fracturing, has the highest sustained gas rate and cumulative production.

The objective of using microseismic data was to assess the four-dimensional development of the induced fracture systems both in space and time. Using real-time microseismic monitoring allows adjustments to the pumping schedule while the treatments take place (i) to improve the effectively stimulated reservoir volume, (ii) to interpret unusual pressure responses, and (iii) to identify contact with potential geohazards. Microseismic monitoring of the individual-well completions and simultaneous fracturing projects showed that substantive changes in fracture network geometry occurred along the laterals. The change in fracture geometry appears to be in response to structural complexity combined with lithological effects.

An important implication of this study is that production improvements or cost savings might be achieved through better integration of surface seismic data, open-hole logs, directional drilling measurements, and borehole-based microseismic monitoring. Completion engineers can take full advantage of the information available when designing stimulation treatments, and make changes to those treatments during pumping operations when needed. The benefits of this approach have been proven in many shale-gas reservoirs around the world.⁸

Acknowledgements

The authors of this paper wish to thank the management of Continental Resources, Inc., and Schlumberger Oilfield Services for the permission to present these data. We also wish to thank Bruce McPherson at Continental Resources for providing additional information concerning Woodford Shale mineralogy and core photos.

References

1. Meyerhofer, M.J., Lolon, E.P., Youngblood, J.E. and Heinze, J.R., "Integration of Microseismic Fracture Mapping Results With Numerical Fracture Network Production Modeling in the Barnett Shale," SPE102103 presented at the 2006 SPE Annual Technical Conference and Exhibition, San Antonio, TX, USA, September 24-27.
2. Warpinski, N.R., Mayerhofer, M.J., Vincent, M.C., Cipolla, C.L. and Lolon, E.P., "Stimulating Unconventional Reservoirs: Maximizing Network Growth while Optimizing Fracture Conductivity," SPE114173 presented at the 2008 SPE Unconventional Reservoir Conference, Keystone, CO, USA, October 10-12.
3. Leonard, R., Woodruff, R., Bullard, K., Middlebrook, M., Wilson, R., "Barnett Shale Completions: A New Method for Assessing Completion Strategies," SPE110809 presented at the 2007 SPE Annual Technical Conference and Exhibition, Anaheim, CA, USA, November 11-14.
4. Mutalik, P. N., and Gibson, R., "Case History of Sequential and Simultaneous Fracturing of the Barnett Shale in Parker County," SPE116124 presented at the 2008 SPE Annual Technical Conference and Exhibition, Denver, CO, USA, September 21-24.
5. Ketter, A.A., Heinze, J. R., Daniels, J. L., and Waters, G., "A Field Study in Optimizing Completion Strategies for Fracture Initiation in Barnett Shale Horizontal Wells," SPE103232 presented at the 2006 SPE Annual Technical Conference and Exhibition, San Antonio, TX, USA, September 24-27.
6. Waters, G., Dean, B., Downie, R., Kerrihard, K. Austbo, L., McPherson, B., "Simultaneous Fracturing of Adjacent Horizontal Wells in the Woodford Shale," SPE119635 presented at the 2009 SPE Hydraulic Fracturing Technical Conference, Woodlands, TX, USA, January 19-21.
7. Waters, G. Heinze, J., Jackson, R. et al, "Use of Horizontal Well Image Tools to Optimize Barnett Shale Reservoir Exploitation," SPE103202 presented at the 2006 SPE Annual Technical Conference and Exhibition, San Antonio, TX, USA, September 24-27.
8. Le Calvez, J. H., Klem, R., Tanner, K. V., Bennett, L., Craven, M., "Real-Time Microseismic Monitoring of Hydraulic Fracture Treatment: A Tool to Improve Completion and Reservoir Management," SPE106159 Presented at the 2007 SPE Hydraulic Fracturing Technology Conference, College Station, TX, USA, January 29-31.