Hydraulic Fracture Diagnostics in the Williams Fork Formation, Piceance Basin, Colorado, Using Surface Microseismic Monitoring Technology

David Abbott, Chris Neale, SPE, and James Lakings, Microseismic Inc., Lynn Wilson, SPE, Jay C. Close, SPE, and Evan Richardson, Chevron

Abstract

A surface microseismic array was utilized to perform hydraulic fracture diagnostics during stimulation of the Chevron Skinner Ridge (SR) #698-22-1 well, Williams Fork Formation (Late Cretaceous), Garfield County, western Piceance Basin, western Colorado. Production from very low permeability Williams Fork gas sandstones requires fracture stimulation to enhance wellbore-to-reservoir connectivity. The use of surface microseismic monitors without borehole equipment in downhole configurations represents a relatively new and untested technology for hydraulic fracture diagnostics. Analysis of the surface microseismic data was carried out for five (5) hydraulic fracture stages to: (1) determine the applicability of the surface microseismic approach in the absence of an offset observation well; and (2) characterize fracture height, azimuth, length and symmetry with respect to rock properties.

Hydraulic fracture stimulations to date at SR have encompassed limited entry “waterfrac” treatment techniques. The hydraulic fracture characteristics were interpreted to document possible influences that natural fractures, horizontal stress trends and sandstone channel orientations may have had on hydraulic fracture emplacement. The Williams Fork Formation at SR contains natural fractures, and the primary open natural fracture sets strike generally east-west. Healed natural fracture sets strike generally northwest-southeast. The current principal horizontal stress trends are roughly east-west. The fluvial Williams Fork sandstone bodies have highly variable orientations due to meandering and braided stream depositional origins, but many channels trend roughly east-west and northwest-southeast. The SR #22-1 well is located in a deep and relatively narrow (1-2 mi wide) north-northwest-south-southeast trending valley roughly 2,000 ft below the adjacent “mesa” tops, which is an important geomechanical consideration.

The surface microseismic data were of sufficient quality to enable successful interpretations of hydraulic fracture geometries. The hydraulic fracture stimulations were emplaced progressively uphole between 5,298 to 3,372 ft measured depth. The deeper stages grew mainly along east-west and northwest-southeast orientations, and the upper stages formed largely along northwest-southeast orientations. All stages showed asymmetric geometry. The lower stages may have been influenced by the northwest-southeast sandstone body and healed natural fracture orientations, along with east-west sandstone body, primary open natural fracture and horizontal stress directions. The upper stages may have been more influenced by the northwest-southeast sandstone body and healed natural fracture orientations, and topographic effects. Additionally, during some stimulation treatments, shallower stages appeared to be in vertical communication with previous deeper stages. A possible tectonic fault that had not been mapped due to widely spaced well control may have further influenced hydraulic fracture growth in one stage.

Introduction / Purpose of Study

The purpose of this paper is to present a case study of a passive surface emission tomography (PSET®) microseismic experiment conducted in a well in the Williams Fork Formation, Piceance Basin, western Colorado. The Williams Fork is widely recognized as a classic Western Interior USA low permeability (“tight”) gas sandstone (TGS) play, and is being actively developed by a host of major and independent companies. Chevron amassed approximately 100,000 acres of fee land over many years at “Skinner Ridge” (SR) in Garfield County, centered roughly 15 mi northwest of Debeque, at the time for the vast oil shale resource potential. The TGS potential at SR has been known since the late 1980’s, partly as a result of tests of the coal gas potential in six (6) wells in the Cameo coal zones at the base of the Williams Fork Formation. A combination of recent price, technology, and portfolio drivers resulted in a 14-well Williams Fork delineation program at SR in summer 2005 through summer 2006. The delineation well production rates, decline curve profiles and estimated ultimate recoveries (EUR’s) satisfied economic hurdles, and planning for full field development starting in mid-2007 was authorized.
The passive surface microseismic program for hydraulic fracture stimulation (“frac”) diagnostic interpretations at SR was conceived in part because no closely spaced offset wells were available in this particular case for downhole microseismic monitoring efforts. Also, significant topographical constraints rendered surface tilt meter monitoring impractical. The results of successful downhole microseismic measurements have been publicly documented for several Piceance Basin research and industry development wells (cf. Wolhart et al., 2005; Warpiniski et al., 2004; 1997; 1998a, 1998b; Schemeta et al., 1994; Teufel et al., 1984), and numerous proprietary investigations have also been performed. The passive surface microseismic approach (see Duncan, 2006; 2005a; 2005b, 2004) represents a fairly new and somewhat untested technology for hydraulic fracture diagnostic studies. Passive seismic is a non-invasive geophysical technique requiring no artificially generated seismic source. Microseismic activity is expected to occur as a result of the hydraulic fracture stimulations.

Surface microseismic monitoring technology was tested as a viable alternative to downhole techniques. While the surface microseismic monitoring recovers a lower frequency signal and has a higher detection threshold, it offers the benefit of providing a broader and more uniform area of coverage over the objective reservoir. No other hydraulic fracture diagnostic measurements had been previously collected at SR. Future microseismic monitoring of Williams Fork stimulations using both surface passive and downhole technologies as SR development drilling progresses will be performed as necessary to help optimize stimulation design and reservoir management.

**Geologic / Reservoir Characteristics at Skinner Ridge**

The Williams Fork Formation in the Piceance Basin has been known since at least the 1950’s to hold tremendous gas in place (GIP) resources. The challenge has long been to commercially develop the huge natural gas volumes present in what is now widely recognized as a TGS play. A plethora of Piceance TGS geologic, geophysical, and engineering (drilling, reservoir, stimulation and production) literature has been published as a result of industry, US Dept. of Energy (DOE) and Gas Research Institute (GRI; now Gas Technology Institute) investigations since the 1970’s. The Multiwell Experiment (“MWX;” then later “MultiSite” or “M-Site”) investigation of Williams Fork and underlying Mesaverde TGS near Rifle, Colorado in the east-central Piceance Basin (cf. Northrop and Frohne, 1990; 2003; Nelson, 2003; Kuuskraa et al., 1999) is a remarkable example of the successful research initiatives that continue to benefit TGS development. Publications from such efforts, along with offset well production data, in-house well files and meetings with offset royalty interest operators, enabled Chevron personnel to formulate detailed predictions of geologic and reservoir characteristics prior to SR delineation drilling. A listing of selected publicly available references that describe Williams Fork TGS is given below.

- Williams Fork play overview: Kuuskraa et al., 1999.
- Stratigraphy (Figure 1) and sand body geometry: Cole and Cumella, 2003; Hettinger and Kirschbaum, 2002; Lorenz et al., 1985.
- Sequence stratigraphy: Patterson et al., 2003.
- Source rock analysis and hydrocarbon generation: Yurewicz et al., 2003.
- Natural fractures: Lorenz and Finley, 1991; Lorenz, 2003; Gomez et al., 2003.
- Nuclear magnetic resonance log interpretation: Lipinski et al., 2003.
- Image log interpretation: Koepsell et al., 2003.
- Petrography, mineralogy and reservoir characteristics: Pitman et al., 1989.

The results of comprehensive formation evaluation indicated that SR geologic and reservoir characteristics fall within the observed ranges for well documented offset fields, including Grand Valley, Parachute, Rulison and Mamm Creek. A summary of several Williams Fork TGS characteristics at SR is given below.

- Geologic age: Late Cretaceous.
- Gross interval thickness: 2,000-2,500 ft.
- Gross interval depth: 3,000-7,000 ft.
- Individual sand thickness: 20-50 ft.
- Number of net perforated sandstones per well: 20-40.
- Net perforated thickness per well: 300-500 ft.
- Matrix porosity: 6-12%.
- Matrix permeability: 0.01 md to micro- and nano-darcy range.
- Mineralogy: quartz and feldspar framework grains; pervasive secondary clays.
- Pressure gradient: slightly overpressured to normal to slightly underpressured.
- Gas composition: 96-97% C1-5; remainder mostly CO2.
- Depositional environments: fluvial (meandering and braided streams).
- Sand body orientations: variable from north to south; average northeast, east and southeast.
- Primary natural fracture strike / dip: approximately east / nearly vertical.
- Faults: no faults recognized with available SR control (~ 20 wells) and 2D seismic.
- Folds: Crystal Creek Anticline (northwest strike in eastern SR) and Clear Creek Syncline (northwest strike in central SR; see Hail and Smith, 1997; Hail et al., 1989). All folds are gentle, regional features.
• Primary horizontal stress orientation: approximately east-west.

The SR area is located in the heavily eroded reaches of the Colorado River valley in western Colorado. The SR #22-1 microseismic test well (Figure 2), in SW Sec. 22, T6S, R98W, has a KB elevation of 5,708 ft, and lies in a north-northwest – south-southeast-trending valley one (1) to two (2) mi wide and roughly 2,000 ft below the adjacent “mesa” tops. The topographic effects of valley trend, width, and depth on horizontal stress azimuth are important geomechanical considerations (cf. Clark, 198333; Lorenz et al., 199334), which can in turn affect hydraulic fracture propagation and interpretation.

**Stimulation Design and Operations**

Hydraulic fracture stimulations to date at SR have encompassed multi-stage limited entry “waterfrac” treatment techniques similar to those used by some offset operators. Typical waterfracs of 800,000 gal of water and 835,000 lbs of 30/50 mesh sand were pumped at 50 barrels per min (BPM). Gross intervals were usually kept to less than 300 ft, and roughly four (4) to six (6) channel sandstones per stage. Limited entry designs with 25 total perforations per stage were typical. Maximum sand concentration was generally 2.0 ppg. The sand and pad were tagged with radioactive (RA) materials, and post-frac tracer logs were collected to further facilitate fracture stimulation diagnostics. Production logs were also obtained to help refine inferences regarding geologic / reservoir vs. stimulation / production affects on production rates and EUR’s.

**Microseismic Field Operations**

The SR #22-1 seismometer array (Figure 3) consisted of 588 vertical component stations arranged in a radial pattern containing 11 “spokes” centered on the wellhead. The number of stations per spoke varied, but six (6) vertical component geophones per station were utilized. The six (6) geophones per station were arranged inline along a length of 50 ft. Stations were spaced along each spoke at 75 ft.

One of the spokes was used as a “walk away” at the SR #22-1 wellhead. Two stations were placed on the well head as “uphole” stations with the eight (8) remaining stations placed along a line “walking away” from the well at 50 ft intervals. The “uphole” and “walk away” stations were used primarily for determining the timing of the “string” shot and perforation (“perf”) shots.

Continuous seismic data were recorded using a Sercel 408 XL system. A total of 72 hrs 23.5 min of data were recorded during the five (5) stages of stimulation and flowback operations. The data were stored in 8,687 30-sec increment files.

**Velocity Model Construction and Depth Tie**

The velocity model used to image the microseismic events was constructed from the sonic log measured in the SR #22-1 well. The sonic log data were converted from microsec/ft to ft/sec. A polynomial trend line was fit to the sonic velocity curve and used to represent a smoothed velocity function. The smoothed velocity curve was broken into 50 ft intervals, with a 1,000 ft weathering layer (velocity of 8,000 ft/sec) added above the well datum to allow for elevation corrections.

The velocity model was calibrated to depth by imaging known events (string and perforation shots) in X/Y (horizontal) and Z (depth). Two (2) string shots were attempted: one deep at 5,303 ft measured depth (MD); and one shallow at 3,367 ft MD. The shallow string shot was visible in the raw data and correctly imaged by PSET in X/Y and Z directions. Two additional attempts were made to fire the deep string shot, but none were successful due to mis-fire. A large perforation shot at a depth of 5,297 ft was also visible in the raw data and correctly imaged by PSET in X/Y, but was imaged 200 ft too shallow (Z). The initial velocity model did not adequately represent the slow velocities of the Cameo coals in the lower Williams Fork zones. Thus, slower velocities were incorporated across the bottom 1,000 ft of the well. The final velocity function is presented in Figure 4.

**PSET Data Processing and Analysis**

The PSET processing procedure is a beam-forming technique that is principally designed to increase the signal-to-noise (SNR) ratio through the power of the stack. The stacking process was run for each stage over a gridded 3D interval velocity volume with X/Y/Z cell spacing of 50 ft. The dimensions of the processed cube that was used to image the microseismic events were 2,000 ft on a side, and the cube was centered on the perforation for the particular stage. A series of discrete time intervals was run through PSET, which resulted in a seismic energy calculated for each cell in the volume for each time interval. The energy calculations were made over a one (1) sec interval. For each one (1) sec stack volume, the cell with the highest seismic energy amplitude was extracted as an X/Y/Z data point. These sequential data points were analyzed to separate signal from noise in order to map the microseismic activity.

The extracted points were plotted against the fracture stimulation pressure curve to allow for inspection of amplitude distributions, and provide for an interpretive selection of an energy cut-off value. The resulting set of data points was visualized in 3D software. Each point was represented by a square positioned in space. The square had size representing the relative amplitude of the microseismic event, and color representing the relative time sequence. Animations (“movies”) were made of the data points appearing in time with the stimulation pressure / slurry rate / slurry density curves shown for reference. The described process and analysis was designed to decimate approximately 99.995% of the data, so that the remaining events were several standard deviations above the mean. Interpretations of microseismic “fracture fairway” dimensions were then performed.

Microseismic events were observed for each stage. These events were classified as “frac-related events” or “geologic-related events.” Frac-related events were the clustering of events close to the well bore / perforation zone that appeared to be directly related to the hydraulic fracture emplacement. These events tended to form early in the pumping process and
migrated rapidly away from the well along clearly defined azimuths during the course of the treatment. Other events also formed in a linear band during the course of the Stage 1 pumping operation, but at distances much larger than was to be expected as a result of the hydraulic fracture design. These events occurred at the start of and throughout the duration of the pumping operation, but were located peripherally to the activity centered on the well. The peripheral events were referred to as geologic-related events.

The fracture geometries presented here do not include the geologic-related events. These events are believed to represent reactivation of a critically stressed, pre-existing fault near the well, and not the emplacement of a hydraulic fracture. Slip along this fault was probably related to the change in the state of stress as a result of the hydraulic fracture emplacement. However, it is known that the geometries of hydraulic fractures are complicated. Many factors influence fracture stimulation geometries, including (but not limited to) the lithologies, natural fractures, stress fields, and structures. It is likely that there will be aseismic zones associated with the fracture stimulations as they form, and that the seismicity will "jump around" in time. Local geologic features such as faults and other zones of different connectivity or permeability may become focal points for seismicity. Microseismic fracture fairways may or may not represent effective fracture lengths and reservoir-to-well connectivity that is contributing to production because of the (1) possibility of aseismic fracture development, (2) fractures closing after stimulation, and/or (3) the reactivation of pre-existing faults.

Examples of the microseismic interpretations for the SR #22-1 well are given in Figure 5a-b. A brief discussion of the microseismic analysis for each stage, and possible inter-stage vertical communication in some instances, is given below.

Stage 1 Analysis (Depth 4,990-5,298 ft; 308 ft gross interval).

Stage 1 had five (5) sand intervals perforated with 20 holes and was stimulated with 150,354 lbs of 30/50 sand and 152,629 gal of water pumped at 45 BPM. RA tracers indicated a gross frac height at the wellbore of 351 ft.

Microseismic events imaged during Stage 1 formed a single, linear fairway having an azimuth of 101 deg and a length of ~200 ft. The epicentral distribution along the fairway scattered around the linear trend, thus giving the fairway an apparent width of 50 ft (the width of a migration cell). The data interpretations were not able to resolve whether the fracture fairway consisted of a single through-going fracture plane, or whether it consisted of several closely spaced en-echelon segments. Microseismic events formed with a total height of ~500 ft. The fairway developed at the beginning of stimulation pressure and was mostly defined within a time interval of approximately 5 min. It is inferred that fracture growth was asymmetric in the direction of maximum principal horizontal stress (approximately east-west) and/or east-west trending sandstone channels.

Geologic-related microseismic events imaged during Stage 1 also formed along what appeared to be a pre-existing fault zone oriented northeast-southwest. The strike of this fault was not anticipated based upon SR geologic investigations. The hydraulic fracture development is believed to have been influenced by this structural feature, since the interpreted microseismic fairway terminated at the intersection of this fault. A fault with the northeast-southwest orientation and in this location had not been mapped using well control and 2D seismic. This fault was only seen to be seismically active during Stage 1 and did not show any significant seismic activity during the later stages.

Stage 2 Analysis (Depth 4,732-4,868 ft; 138 ft gross interval).

Stage 2 had six (6) sand intervals perforated with 24 holes and was stimulated with 112,139 lbs of sand and 116,000 gal of water pumped at 55 BPM. Radioactive tracers indicated a gross frac height at the wellbore of 199 ft.

Microseismic events imaged during Stage 2 formed a single fairway having an azimuth of ~325 deg and a length of ~170 ft. Because of model discretization, the fairway cannot be resolved to widths of less than ~50 ft. Microseismic events formed up to a total height of ~400 ft. The fairway developed within a time interval of approximately 7 min, early in the fracture stimulation. The fracture growth was asymmetric in a northwest direction. Hydraulic fracture growth may have progressed along pre-existing healed natural fracture zones, and/or sandstone channels, that both trend northwest-southeast.

Stage 3 Analysis (Depth 4,182-4,456 ft; 274 ft gross interval).

Stage 3 had five (5) sand intervals perforated with 24 holes and was stimulated with 146,000 lbs of 30/50 sand and 171,500 gal of water pumped at 55 BPM. RA tracers indicated a gross frac height of 270 ft at the wellbore.

Microseismic events imaged during Stage 3 formed three (3) fairways, the first having an azimuth of ~270 deg and length of ~200 ft. Again the events occupied a zone of ~50 ft around the linear trend. Microseismic events formed up to a total height of ~300 ft. The first fairway developed within a time interval of approximately 5 min, early in the frac. The second fairway developed at an azimuth of ~90 deg, with a length of ~200 ft and a fairway width of ~75 ft. Microseismic events formed up to a total height of ~300 ft. The fairway developed within a time interval of approximately 30 min, midway through the frac. The first and second fairways may have been influenced by the east-west-trending primary natural fractures, sandstone channels and horizontal stresses.

The third fairway progressed in a vertical manner. Microseismic events formed up to a total height of ~350 ft. The fairway developed within a time interval of approximately 15 min, at the end of the frac.

It is interpreted from microseismic observations that fracture growth was asymmetric. Microseismic events did not originate at the well bore, which raises the speculation that fracture growth from the well may have been either aseismic or too small to be detected. Alternatively, there may have been a pre-
existing fluid pathway that channeled the fluids away from the well. It is speculated that there may have been communication behind the casing with Stage 2.

**Stage 4 Analysis (3,658-3,991 ft; 333 ft gross interval).**

Stage 4 had eight (8) sand intervals perforated with 26 holes and was stimulated with 118,000 lbs of 30/50 sand and 94,000 gal of water pumped at 60 BPM. RA tracers indicated a gross frac height of 365 ft at the wellbore.

Microseismic events imaged during Stage 4 formed a single fairway having an azimuth of ~308 deg. The fairway length was ~225 ft with a fairway width of ~75 ft. The increased width may be related to increased fracture complexity. Microseismic events formed to a total height of ~250 ft. The fairway developed within a time interval of approximately 11 min, early in the frac.

It is interpreted from microseismic observations that fracture growth was asymmetric in the northwest direction. Fracture growth may have occurred along pre-existing healed natural fracture and/or sandstone channels that trend northwest-southeast.

**Stage 5 Analysis (3,372-3,553 ft; 181 ft gross interval).**

Stage 5 had three (3) sand intervals perforated with 22 holes and stimulated with 83,000 lbs of 30/50 sand and 64,000 gal of water pumped at 51 BPM. RA tracers indicated a gross frac height of 280 ft at the wellbore.

Microseismic events imaged during Stage 5 formed three (3) fairways, the first having an azimuth of ~308 deg. The fairway half-length was ~400 ft, with a fairway width of ~75 ft. Microseismic events formed up to a total height of ~300 ft. The fairway first developed within a time interval of approximately 5 min, early in the frac. The second fairway had an azimuth of ~308 deg, half-length of ~400 ft, and width of ~75 ft. Microseismic events formed with a total height of ~300 ft. The third fairway had an azimuth of ~219 degrees, length of ~300 ft, and width of ~50 ft. Microseismic events formed up to a total height of ~300 ft. All three (3) fairways exhibited microseismic events during the final 27 min of the frac.

It is interpreted from microseismic observations that fracture growth initially was asymmetric in the northwest direction. Secondary fracture growth appeared to occur on a secondary wing in the orthogonal southwest direction. Fracture growth may have occurred along pre-existing healed fracture zones, which trend northwest-southeast, and sandstone channels, some of which trend northwest-southeast and southwest-northeast.

**Inter-stage Vertical Communication**

Composite views showed stages that caused microseismic activity in the same rock volume, which may indicate inter-stage communication (Figure 6). Stages 2-3 were stimulated into the same volume in depth and space even though they were pumped on two different days, which indicates that these two stages were possibly in vertical communication. Stages 4-5 were stimulated into the same volume in depth and space, but were pumped on the same day. This may signify that these two stages were possibly in vertical communication. However, there remains the possibility that there was still seismic activity occurring in Stage 4 after the treatment, which was not in response to the Stage 5 pumping operation.

**Conclusions**

The use of surface microseismic monitors without borehole equipment in downhole configurations represents a relatively new and untested technology for hydraulic fracture stimulation diagnostics. Passive surface emission tomography (PSET®) of the fracture stimulation treatments in the Skinner Ridge (SR) #22-1 well (Williams Fork tight gas sandstones, western Piceance Basin, western Colorado) was successful in estimating fracture fairway azimuths and dimensions. PSET has provided enough information about the hydraulically induced fracture orientations to help select initial development well bottomhole locations.

PSET imaging of the perforation shot from Stage 1 demonstrated that small amplitude microseismic events were accurately located at measured depths of up to 5,297 ft. The significance of this capability is that: (1) the velocity model was calibrated; and (2) microseismic events during hydraulic fracturing operations were imaged in a valid manner. The uniform subsurface coverage provided by the surface array helped to overcome any systematic biases in the observations as they may have related to hydraulic fracture symmetry. Observations of microseismic activity during fracture stimulation operations provided useful information about the complexities of the SR #22-1 hydraulic fracture geometry and rock properties, as listed below.

- Fracture stimulation-related and geologic-related microseismic events were observed for each stage.
- Microseismic fairway azimuth, length, height and symmetry were inferred for each stage.
- Hydraulic fracture growth appeared to form primarily in two sets of azimuthal orientation, roughly east-west and roughly northwest-southeast. Fracture emplacement was asymmetric.
- The primary horizontal stress is interpreted to generally rotate from roughly an east-west direction at deeper depths corresponding to Stages 1, 2, and 3, to roughly northeast-southeast for shallower depths corresponding to Stages 4 and 5. However, the rotation was not uniform.
- Hydraulic fracture emplacement was influenced by sandstone channel orientations (many of which are east-west and northwest-southeast), open east-west primary natural fractures, northwest-southeast healed natural fractures, east-west primary horizontal stress, and by the deep, narrow valley topographical influences.
- Possible inter-stage communication was inferred by observing rock volumes having microseismic events from multiple stages. Stages 2-3 and 4-5 may have been in vertical communication.
Future microseismic monitoring of Williams Fork stimulations using both surface passive and downhole technologies as SR development drilling progresses will be performed as necessary to facilitate optimization of stimulation design and reservoir management.

Acknowledgments

The authors appreciate the project funding and permission from Chevron management to publish and present this paper. The service company personnel that facilitated the field operations are also thanked for their safe and diligent work.

References Cited


Figure 1. Piceance Basin Williams Fork and adjacent stratigraphy (Cole and Cumella, 2003).  

Figure 2. Piceance Basin map (cf. Johnson, 1989) with Skinner Ridge location (marked with an “X.”).
Figure 3. Field seismometer array map for Skinner Ridge #698-22-1.

Figure 4. Final velocity model for Skinner Ridge #698-22-1.
Figure 5a-b. Stage 5 interpretation example, map and cross section views, Skinner Ridge #698-22-1.