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Simultaneous Hydraulic Fracturing of Adjacent Horizontal Wells in the Woodford Shale

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Abstract

Hydraulic fracturing of horizontal wells in shale gas reservoirs is now an established, commercially successful technique. The evolution of the completion technique has reached the point that numerous stimulation stages through multiple perforation clusters in wellbores with some form of annular isolation is now an accepted practice. The objective is to place multiple closely spaced hydraulic fractures. This has proven to be a viable development strategy for many shale reservoirs in North America.

To further enhance the recovery factor in these ultra low permeability reservoirs simultaneously hydraulically fracturing of adjacent wellbore is increasingly being tested. Most of the time this is performed in horizontal wellbores paralleling each other. The goal is to create hydraulic fractures more closely spaced than can be achieved from a single wellbore. When real time microseismic monitoring of the stimulation treatments is incorporated changes can be made "On-the-Fly" to improve the effective stimulated reservoir volume.

Continental Resources has employed simultaneous hydraulic fracturing as a development strategy for their Woodford Shale acreage in the Arkoma Basin of Eastern Oklahoma. To monitor the effectiveness of the stimulations geophones have been deployed into horizontal wellbores to record microseismic events when offsetting vertical wellbores are unavailable. Cased hole sonic logs have also been run to quantify cement bond quality, estimate stress variation along the lateral, and to pick optimum perforating points.

This paper reviews the methodology employed in the completion design and process. The impact of the simultaneous stimulations and geologic structure on the fracture geometry are shown as well as the impact on well productivity.

Woodford Geology

The Devonian Woodford shale is a prolific gas producer in the western Arkoma Basin in Atoka, Coal, Hughes, and Pittsburg Counties, Oklahoma where there are over 527 Woodford completions since January, 2004. The majority of these wells are horizontal with multistage fracture stimulation treatments performed on them. In these four counties, the Woodford formation ranges in depth from approximately 4,000 ft to over 14,000 ft and varies in thickness from 35 ft to over 280 ft. In the area covered by this paper, the Woodford formation is at a depth of 6,000 ft to 7,700 ft and is 160 ft to 180 ft

thick. The Woodford lies upon the post-Hunton unconformity and is underlain by Hunton Limestone with the calcareous Mayes formation overlying the Woodford.

The Woodford Shale is an organic-rich, siliceous shale with 48 - 74% quartz, with an additional 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 (Figure 1).

In this area, seismic data indicates there is an E-W trending fault/fracture network with an ENE-WSW secondary fault/fracture network (Figure 2). The horizontal wells in this area target the Woodford A interval and are drilled N-S to maximize the drainage of the section. This orientation also approaches the azimuth of the minimum horizontal stress (σ_h) which results in hydraulic fractures that are perpendicular to the wellbore. This stress orientation has been identified by induced fractures on image logs (Figure 3) and confirmed by microseismic imaging of hydraulic fractures.

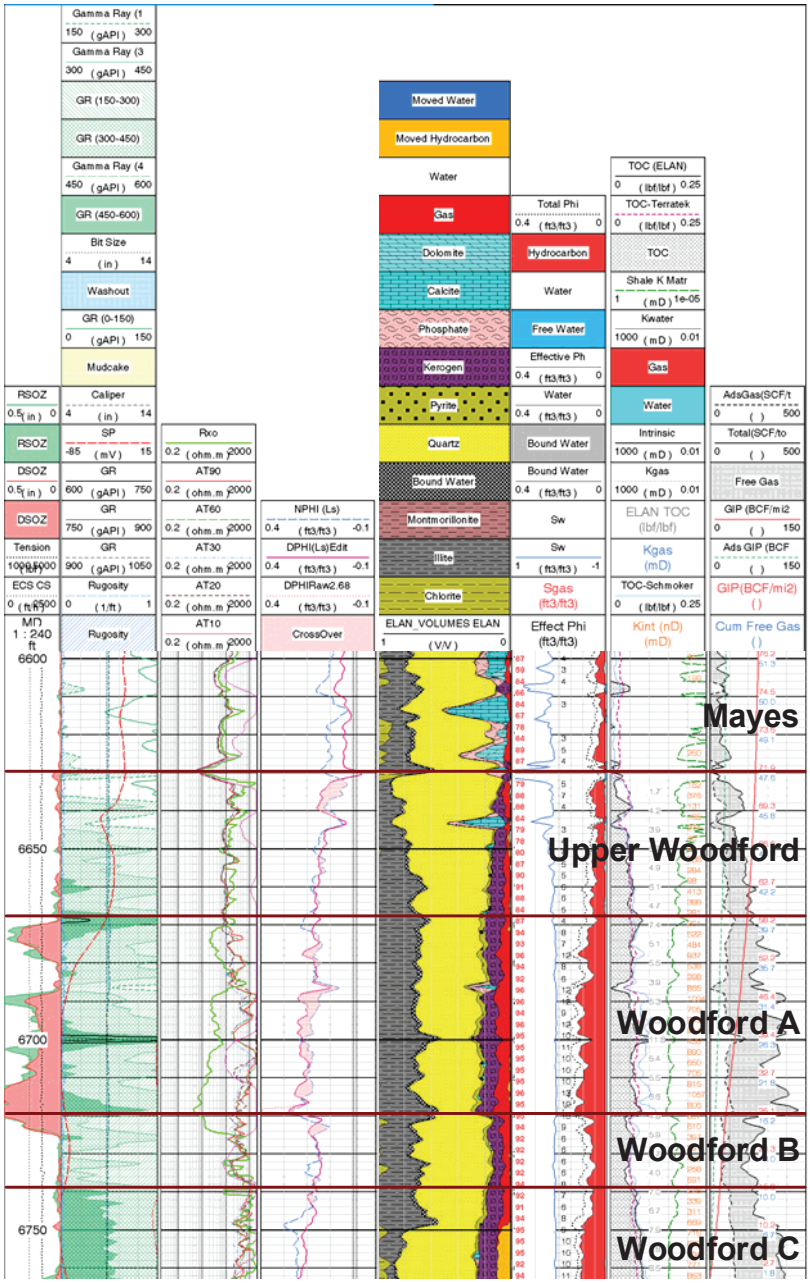

Figure 1 – Woodford Shale Type Log with sub-divisions noted. Log does not penetrate all of Woodford

Hydraulic Fracturing of Shales

Hydraulic fracturing of ultra low permeability reservoirs is required to establish commercial productivity. Commercial shale reservoir permeabilities are in the range of 200 nd, or 0.0002 md. With formation permeabilities of this magnitude the pressure drop in the system occurs primarily in the reservoir near the fracture face. Analytical techniques support this conclusion even assuming no fracture face damage[1]. Figure 4 shows the source of pressure losses versus time in a low permeability shale reservoir assuming no fracture face skin.

Reservoir simulations have also shown that this is the case for many years after production commences (Figure 5)[2,3]. As Figure 5 indicates, large sections of the reservoir are at initial reservoir

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pressure after 10 years of production, when hydraulic fractures are spaced 1,000 ft apart in a 400 nd shale gas reservoir. Even after 60 years of production the reservoir pressure still approaches 50% of its initial value for this fracture spacing. The recovery factor is increased dramatically when the hydraulic fractures are spaced closer together. As indicated by Figure 6 a 250 ft hydraulic fracture spacing drains as much of the reservoir in 10 years as the 1,000 ft spacing does in 60 years. With this spacing the reservoir is largely depleted between the fractures after 60 years of production.

Recovery can be accelerated further by even closer spacing of hydraulic fractures, or in reservoirs where dense natural fractures that remain open during production are present. Ultimately the optimum spacing of hydraulic fractures is driven by two parameters:

- The incremental cost associated with creating an ever denser fracture system versus the productivity improvement from the denser fracture network.
- The ability to physically, continually propagate hydraulic fractures in close proximity to one another.

An investigation of theoretical hydraulic fracture spacing provides a lower bound for their proximity. As a first pass one can use Hooke's Law to determine realistic minimum hydraulic fracture spacing. For this application Hooke's Law takes the form shown in Equation 1:

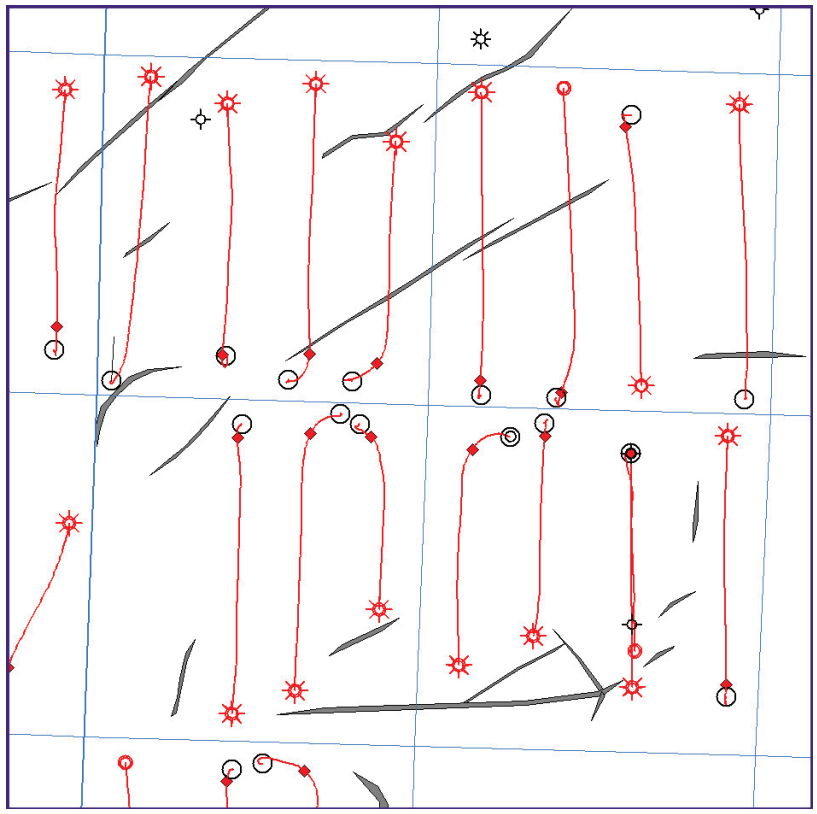

Figure 2 – Woodford structure showing an E-W fault/fracture network and a secondary NE-SW system. Wellbores are oriented N-S for most effective development. Blue squares denote 1 mile section lines.

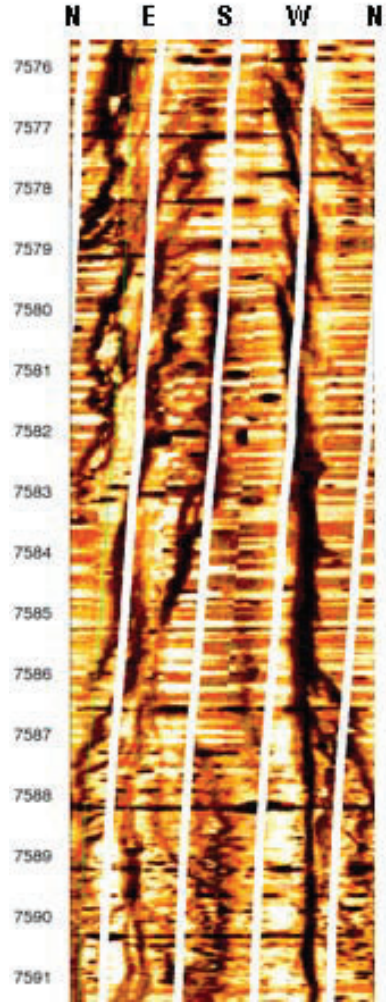

Figure 3 – Woodford FMI Log showing E-W Induced Fractures, the azimuth of the maximum horizontal stress (σ_H) and of hydraulic fractures.

$$\Delta\sigma = E(w/b) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

where E = horizontal Young's Modulus, w = hydraulic fracture width, and b = hydraulic fracture spacing. Figure 7 portrays this stress increase as a function of fracture spacing and Young's Modulus.

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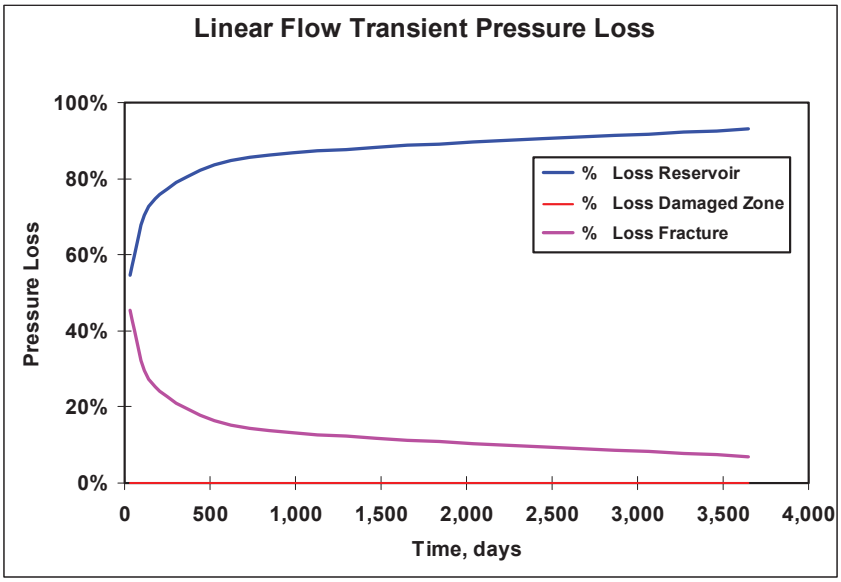
Figure 4 – Sources of pressure loss in a hydraulically fractured shale reservoir showing the majority of the system pressure loss is in the formation, near the fracture face.

Assumptions:
Fracture Length = 1,000 ft
Fracture Conductivity = 8.3 md-ft
Formation Perm = 200 nd
Fluid Viscosity = 0.02 cp
Porosity = 7%
Fluid Compressibility = 0.0001 psi^{-1}
No Fracture Face Skin



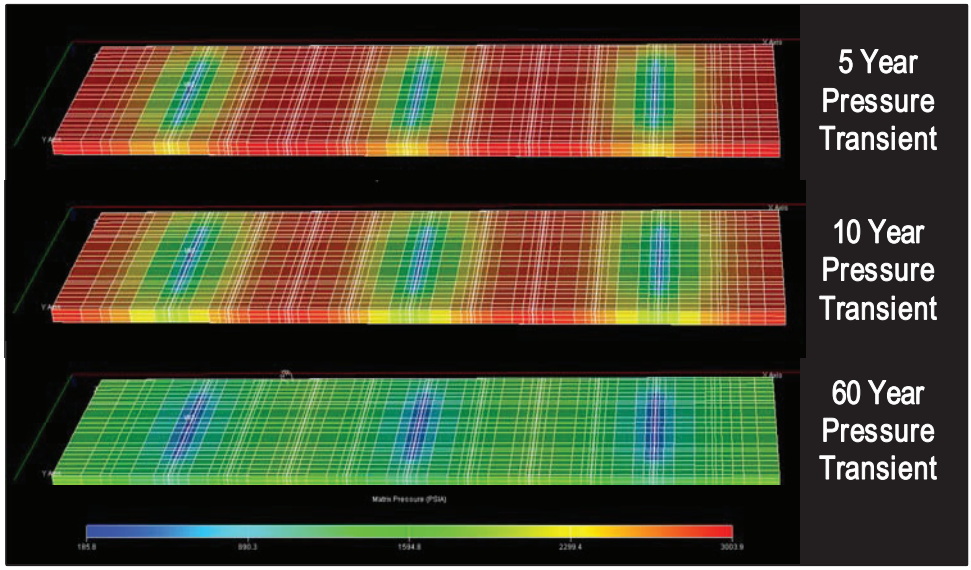
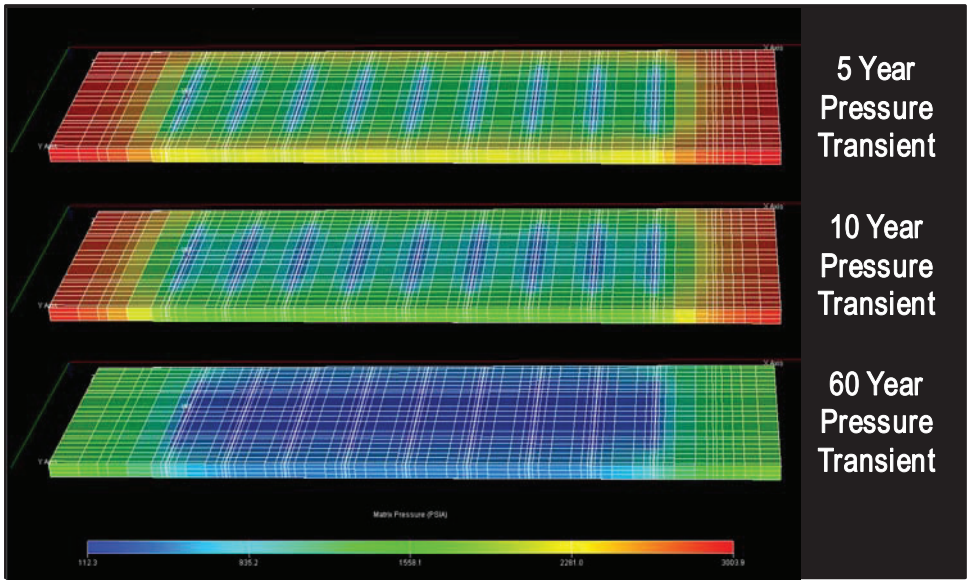


Figure 5 – Pressure Transient in a 400 nd shale gas reservoir with an initial reservoir pressure of 3,000 psi and 500 ft long hydraulic fractures spaced at 1,000 ft intervals.

Figure 6 – Pressure Transient in a 400 nd shale gas reservoir with an initial reservoir pressure of 3,000 psi and 500 ft long hydraulic fractures spaced at 250 ft intervals.



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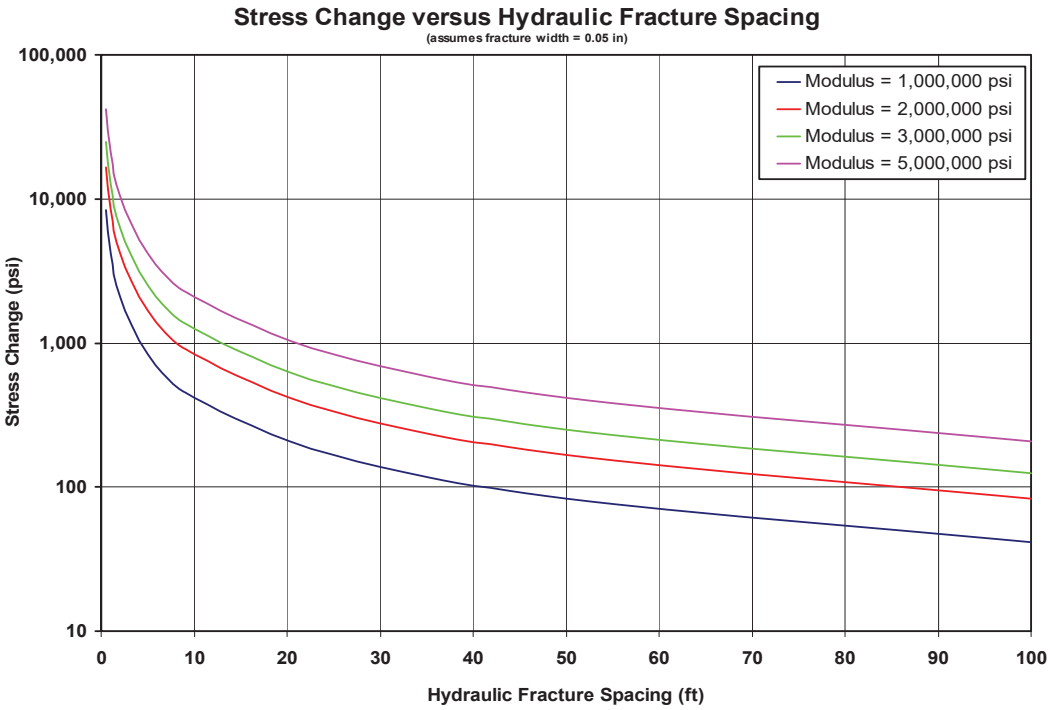

Figure 7 – Stress increase versus hydraulic fracture spacing for various Young's Moduli. The higher the Modulus the greater the stress increase. At very close fracture spacing the stress increases dramatically. A hydraulic fracture width of 0.05 inches is assumed.

Two conclusions are apparent:

- In order for hydraulic fractures to be very close together very high stresses are required. A fracture spacing of 1 ft requires stresses in excess of 4,000 psi for all listed moduli. This is unrealistic and will certainly lead to the truncation of most fractures and the creation of a dominant, single fracture at this spacing.
- The rock stiffness greatly influences the achievable fracture spacing. For example, at a fracture spacing of 25 ft the increase in stress is >800 psi for a rock with a Young's Modulus of $5x10^6$ psi. Yet the stress increase is only 170 psi for a rock with a Young's Modulus of only $1x10^6$ psi.

Fortunately organic-rich shales normally have relatively low Young's Modulus compared to conventional low permeability reservoirs that are candidates for hydraulic fracturing. Therefore, it is easier to place fractures closer together in these very low permeability rocks than in tight sands or carbonates where the Young's Modulus is frequently in excess of $6x10^6$ psi. This example is a gross simplification yet it does provide a measure of scale of hydraulic fracture spacing.

Warpinski and Branagan[4] reviewed the stress alteration associated with hydraulic fracturing, comparing it to field results recorded in the U.S. DOE's Multiwell Experiment Site[5]. This paper focused on the rotation of minimum horizontal stress (σ_h) due to the stress perturbation created from a pre-existing fracture from an offset well. The analytical technique used in this paper[6,7] assumes an infinitely long planar fracture in a homogeneous, elastic and isotropic body. While these simplifying assumptions may be idealistic the method does provide some insight into the potential complexities associated with hydraulic fractures propagating in close proximity to each other. The reader is referred to Reference 4 for the pertinent equations.

Hydraulic fracture rotation is unlikely if there is a large difference in the horizontal stresses, a moderate Net Pressure build, and/or a relatively small fracture height. But this does not mean that the fracture geometry is not impacted by the adjacent fractures. The degree of stress increase associated with a hydraulic fracture varies vertically through the fracture with the highest stress increase occurring at the center of the fracture were the hydraulic fracture width is assumed to be the maximum. From the center

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of the fracture to the vertical fracture tips and beyond the stress declines, eventually decreasing to below the initial, undisturbed value of σ_h because of the tensile forces at the fracture tip (Figure 8). Thus a scenario exists where adjacent fractures may be drawn towards each other at their perimeters yet repelled near the fracture centers where the width is assumed to be the greatest. There is a large increase in shear stress near the fracture tips that will likely preclude the fractures from connecting to form a single fracture (Figure 9). Instead the fractures will likely rotate towards each other and truncate if they are very close to each other.

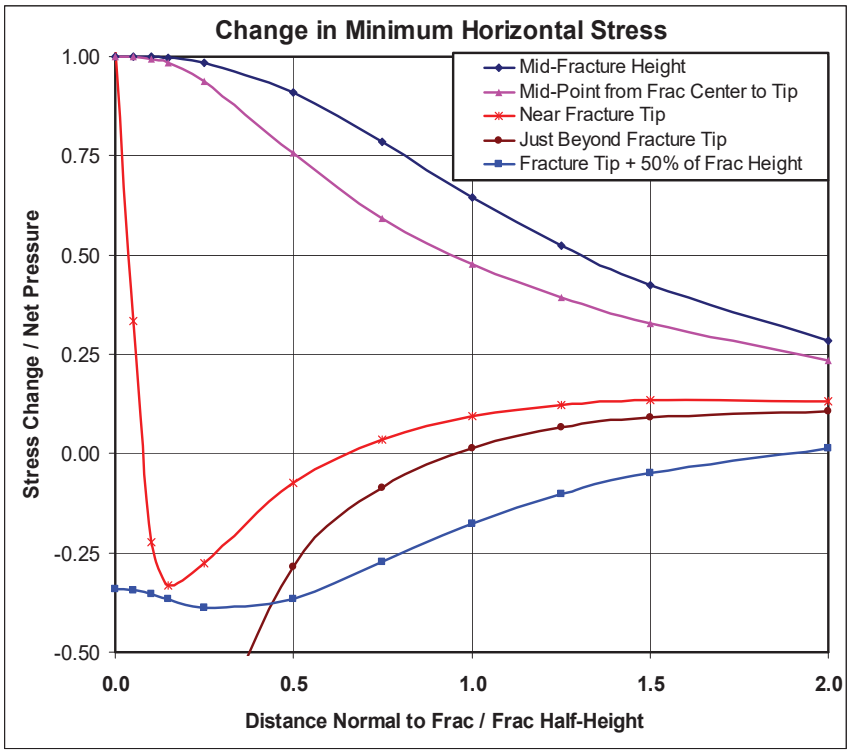

Figure 8 – Change in σ_h due to the presence of a hydraulic fracture. The stress increase is the highest at the center of the fracture and decays as the distance from the fracture increases (Blue Curve). Near the fracture tip the stress actually decreases as the stress in this region is tensile versus compressive (Red & Brown Curves).

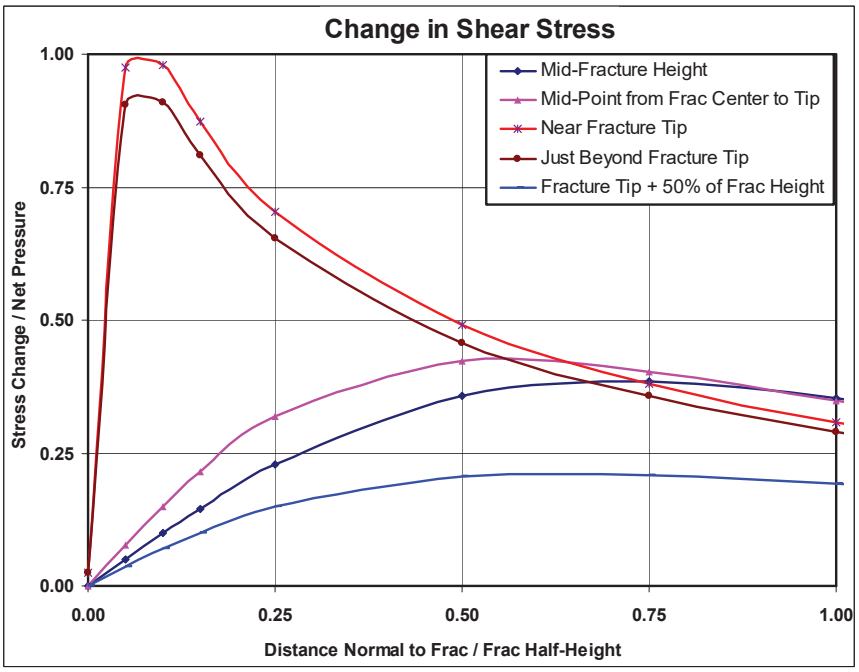

Figure 9 – Change in shear stress due to the presence of a hydraulic fracture. The high shear stress near the fracture tip (Red & Brown Curves) will likely cause the fractures to rotate and truncate if they are in close proximity to each other.

Most horizontal wells in low permeability shales are drilled in the direction of σ_h at deviations slightly greater than 90 degrees. With this orientation it will not be possible to take advantage of the tensile region near the hydraulic fracture perimeter to place fractures closely together within the same wellbore

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because the fracture widths will be largest at the wellbore where the fractures are initiated (Dark Blue Curve in Figure 8). Hence the stress will be higher near the perforation clusters within a horizontal wellbore making hydraulic fracture initiation more difficult if the perforations are spaced closely together.

One method to achieve a dense hydraulic fracture system is to drill hydraulically fractured vertical wells on a dense well spacing. To achieve the required dense fracture network requires multiple vertical wells with a well spacing of approximately 15 acres (Figure 10). This is not cost effective as a new vertical borehole is needed for each stimulation. As previously mentioned, a commonly employed alternative is to drill horizontal wells in the direction of σ_h and to place multiple hydraulic fractures in close proximity to each other. This success of this technique is well documented[8]. A more recent development is the utilization of the pressure alteration due to a stimulation treatment from a horizontal well to alter the hydraulic fracture geometry from a concurrent stimulation treatment being performed on a closely spaced, parallel offset horizontal well.

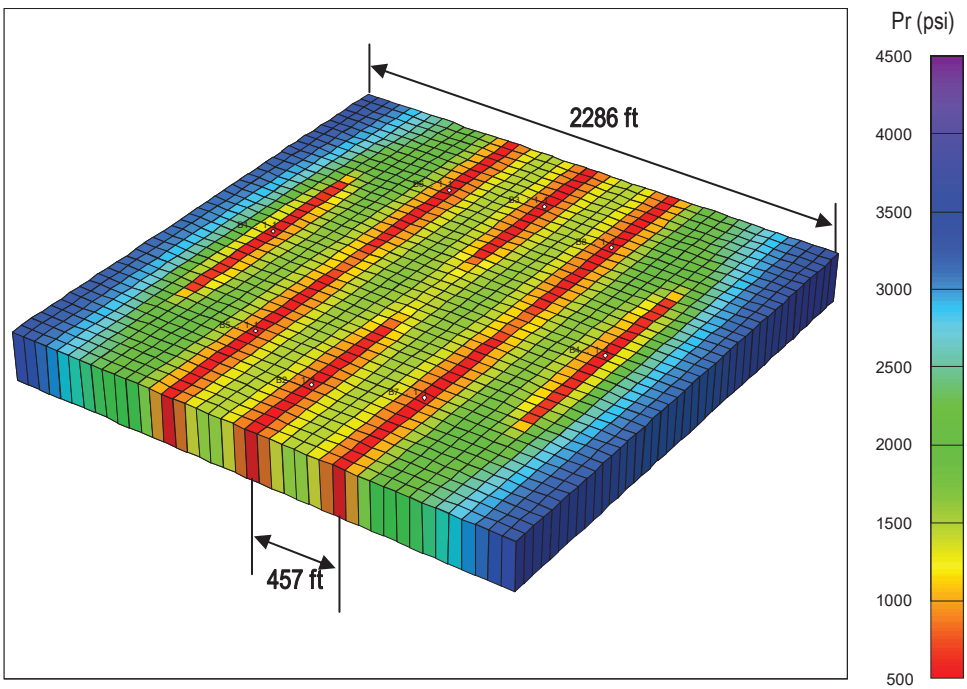

Figure 10 – Reservoir depletion pattern after 30 years in a 200 nd permeability shale gas reservoir with hydraulically fractured vertical wellbores on 15 acre spacing.

Hydraulic Fracture Complexity due to Simultaneous Fracturing

The "Simul-Frac" technique is a method in which adjacent sections of a reservoir are hydraulically fractured from at least two wellbores at the same time. Most of the time the wells are horizontal with the laterals drilled in the direction of σ_h and landed at similar, although not always, the same depth. In such wells the toe sections of the laterals will be stimulated at the same time. Subsequent stages are performed concurrently working from the toe back to the heel of the lateral. The objective is to place hydraulic fractures in close proximity to one another by taking advantage of the tensile stress region near the fracture perimeters.

A number of variations to the technique are commonly employed:

- The depth of the adjacent laterals may vary. Such vertical staggering can take advantage of the tensile region around the top and bottom of the fractures (Figure 8 Red & Brown Curves), not just at the fracture tip, to allow close spacing of fractures.
- More than two laterals can be stimulated at the same time. In some cases up to four parallel laterals have been stimulated at the same time.

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- In ultra-low permeability reservoirs such as shales the stimulations do not necessarily have to occur concurrently. Since there is little to no fluid leakoff into the rock matrix the fracture systems will remain pressurized until flown back. This pressurized system can provide the diversion desired when the adjacent lateral is stimulated subsequent to the initial stimulation.
- This "Zipper-Frac" method provides some significant operational efficiencies:
  - When two wells drilled from the same pad are being stimulated only one stimulation crew and perforating crew is required. While the fracturing crew is stimulating one well, the perforating crew is setting the frac plug and perforating the adjacent wellbore. The two crews continue to work back and forth between the two wells to efficiently complete them in a timely manner.
  - If more than two wells are being stimulated at the same time then a completion sequence can be developed to most effectively create a dense fracture network throughout the acreage. For example, if four laterals are being stimulated with two crews the outer wells can be stimulated first, followed by the inner wells where a more dense fracture pattern can be created. The treatment sizes can be adjusted based on the order in which the wells are stimulated. The completion sequence utilized will be a function of the well spacing, the structural geology, surface logistics, and the desire for hydraulic fracture density versus fracture length.
- A third technique is to completely stimulate one lateral. Then, before fracturing fluid flowback is commenced, completely stimulate the adjacent lateral(s) taking advantage of the pressurized system from the first lateral stimulated. This method has the same operational efficiencies as the Zipper-Frac technique but can be employed when the wellheads are separated requiring movement of the frac crews.

Simultaneous Fracturing Examples in the Woodford Shale of the Arkoma Basin

All discussed wells are operated by Continental Resources, Inc. of Enid Oklahoma and are in Hughes County, Oklahoma, in the western part of the Arkoma Basin. All wells are similarly drilled and completed. All wells are cased and cemented using 5.5 in, 17 lb/ft, P110 casing in 8.5 in hole. Wells are fracture stimulated in multiple stages, each stage stimulating 400 to 500 ft of lateral through 4 to 6 sets of perforations spaced 70 to 125 ft apart. Cement bond logs were run in all wells except in wells where cased hole dipole sonic logs were run to quantify cement bond quality and to estimate σ_h along the lateral. The bond logs were used to place perforation clusters in intervals with similar bond quality and to insure that annular isolation between stages was attained. When practical, perforation clusters were placed in sections with poor cement bond quality to minimize near-wellbore fracture complexity issues due to solids plugging the annulus. When stress profiles were available along the lateral perforations were placed in intervals of similar stress[9]. Coupling these techniques with limited entry perforating increased the odds that all perforation clusters would be active during the stimulation treatments.

Fracture stages contained short perforation clusters varying in length from 1.5 ft to 2.5 ft. The number of perforation clusters varied from 4 to 6 per frac stage. All perforating utilized 6 shots per foot, 60 degree phasing with entry hole diameters of 0.42 in (low side) to 0.32 in (high side). The first stimulation stage perforations were shot via coiled tubing. Subsequent perforations were run on wireline with composite drillable isolation plugs using the pump-down technique in the horizontal section at low injection rates of 2 to 12 bpm.

On all example projects treatment wells were shut-in after fracturing until coiled tubing units were mobilized to drill out all isolation plugs at the same time. Wells were flowed back together within 24 to 36 hours of the end of stimulation operations. Most wells within a project were then put on production

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at the same time. All wells are produced up open ended 2-3/8" production tubing landed in the heel section of the lateral.

Example 1:
The first project area includes six horizontal wells drilled parallel to each other with laterals spaced approximately 1,320 ft apart. Four new wells were drilled between two existing producers. Figure 11 shows the surface layout of the project.

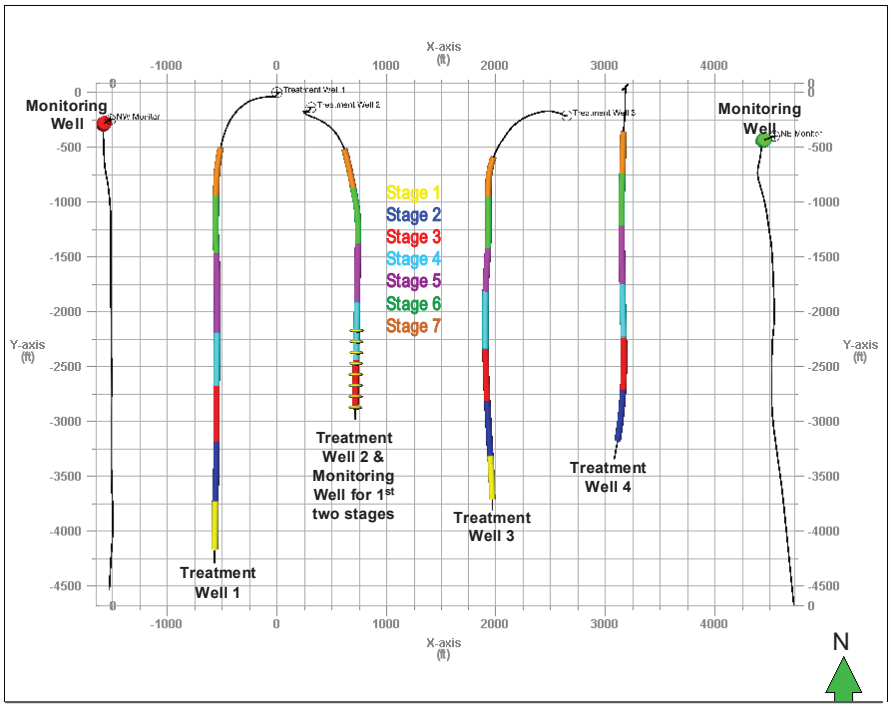

Figure 11 – Layout of the horizontal wells in the Example 1 area. Geophones were run in the vertical section of the perimeter wells for all stimulation treatments and in the short lateral for the initial stimulation treatment on the other three horizontal wells.

Example 1 project area perforation and stimulation design:

- Frac stages spaced every 500 ft along the lateral, with 5 to 7 stages per well
- Four perforation clusters per frac stage, spaced approximately 125 ft apart
- Fluid volumes of 10,000 bbls of Slickwater per frac stage
- 100 mesh sand volume of 75,000 lbs/stage
- 30/50 mesh sand volume of 200,000 lbs/stage
- Injection Rate of 80 bpm
- A total of 22 of the 25 stimulation stages pumped to completion

In order to maximize the advantage of the simultaneous fracturing process, hydraulic fractures induced from individual wellbores must propagate towards each other. There were two suspected fracture orientations based on the strike of faults that were identified by surface seismic data. The orientation of the induced fractures would dictate the number of simultaneously pumped stages required. Seven pumping cycles would be required if the fractures were aligned east to west. Up to 13 pumping cycles would be required if the orientation was aligned with faults that had a strike of N56E. There was an additional concern that the azimuth of the induced fractures might change from stage to stage during the treatment because of the stress changes associated with faults.

Prior to stimulation, wells were logged with a sonic tool, measuring axial, azimuthal and radial acoustic properties from dipole and monopole systems. The predicted direction of the maximum stress was between N79E and N92E, predominantly east-west, along all lateral sections measured. During stimulation, real-time microseismic monitoring and processing were utilized to confirm the direction of fracture propagation. The objectives of microseismic monitoring were:

- Identify the fracture orientation to maximize the interference between simultaneously pumped treatments from adjacent wellbores and adjust subsequent staging based on these results.

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- Identify any effects of hydraulic fracture interference on fracture geometry.
- Better understand the role of geologic structure on the hydraulic fracture geometry.
- Determine the growth in fracture height.

Three wells were used for microseismic monitoring during the project. Geophone arrays were placed in the vertical sections of existing wells located to the east and west of the four treatment wells. The distance from both vertical monitoring wells to the ends of the longest laterals was beyond which all but the very strongest microseismic events could be detected. Therefore, a third geophone array was placed in the horizontal section of the shortest of the four treatment well laterals and was used to monitor the first two treatment stages on the offset wells. The horizontal geophone array was removed following the second stages so that stimulation operations could begin on that well. The location of the geophone arrays with respect to the treatment wells is shown in (Figure11).

Microseismic data for first two stages on the offset wells from the horizontal tool array is shown in Figure 12. The extension of the induced fracture networks from their respective perforation intervals was observed to be in an east to west direction. It is also possible to see clusters of microseismic events along a secondary azimuth oriented generally to the northeast. These events are near structural features identified with 3D seismic within and below the Woodford Shale and do not indicate a change in horizontal stress, but do show how structure can impact stimulation geometry.

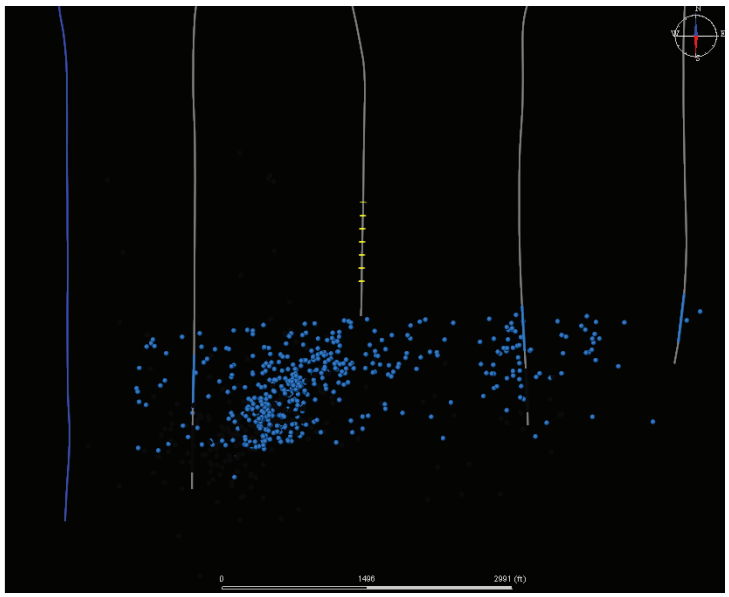

Figure 12 – Microseismic activity from the initial stimulation treatments in Wells 1, 3 & 4 recorded from the horizontal geophone array in Well 2.

The entire set of microseismic data acquired during the project is shown in Figure 13. There are two patterns of microseismic activity visible. Most of the stages produced fracture networks that were complex and do not have well defined azimuths. Some stages show well organized patterns of microseismic activity that are oriented east to west. The stages displaying this behavior originate from the two exterior wells and appear to indicate that asymmetric fracture extension towards the previously completed laterals to the east and west of the project area.

The best example of interaction between simultaneously pumped fracture treatments is found during the sixth treatment stages. The effects of fracture interference on a fracture initiated in an exterior well, Treatment Well 1, and an interior well, Treatment Well 2, can be seen in Figures 14A through 14D. This is one of the few stages where an adequate volume of microseismic data was present to clearly illustrate the activity near the interior wells.

The data is color-coded into four segments, which coincide with key elements of the pumping schedule. The first time period, the green events shown in Figure 14A, occurs while high near-wellbore pressures are present early in the treatment. Figure 14B additionally shows the blue events detected just prior to the time that the fractures appear to meet one another. Figure 14C adds the yellow events recorded up to the final cycle of proppant. Figure 14D adds the red events recorded through the final proppant cycle.

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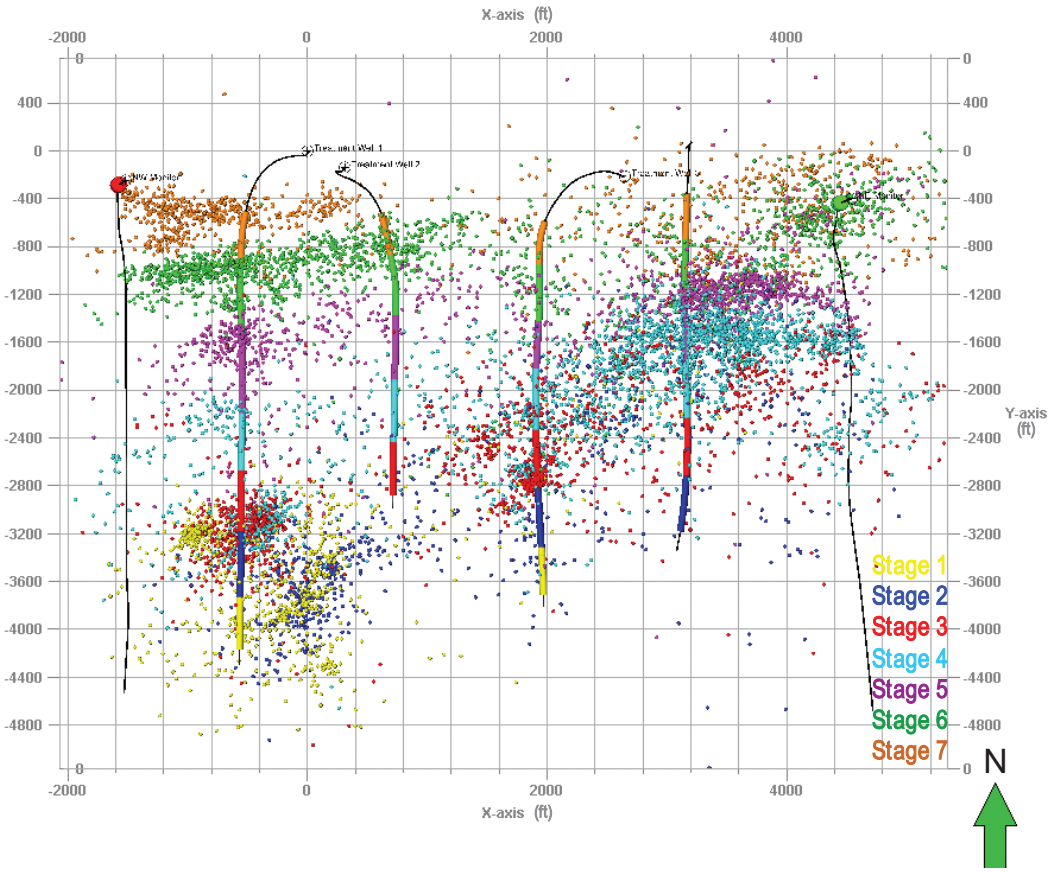

Figure 13 – All of the Microseismic activity recorded from all 25 stimulation treatments. Variations in microseismic activity are apparent with complex networks common in the toe stages and more planar events in the heel stages. Growth towards the outlying existing wellbores was frequently seen once the fractures from offset wells began to interact with one and other.

The fracture network initiated from Treatment Well 1 appears to shift to the west side of the lateral, away from the region of interference, and extends toward the NW Monitoring Well lateral after the microseismic activity from Treatment Wells 1 & 2 merge. The rate of microseismic events generated from this fracture network remains nearly constant throughout the treatment. The volume of the region where microseismic activity is detected from the fracture network initiated in Treatment Well 2 remains almost static after the fracture networks encounter one another. Confining pressure from fractures extending from Treatment Wells 1 and 3 (to the east) appear to impede further extension of the fracture system to the east or west. There is no change in fracture height that can be observed during this time

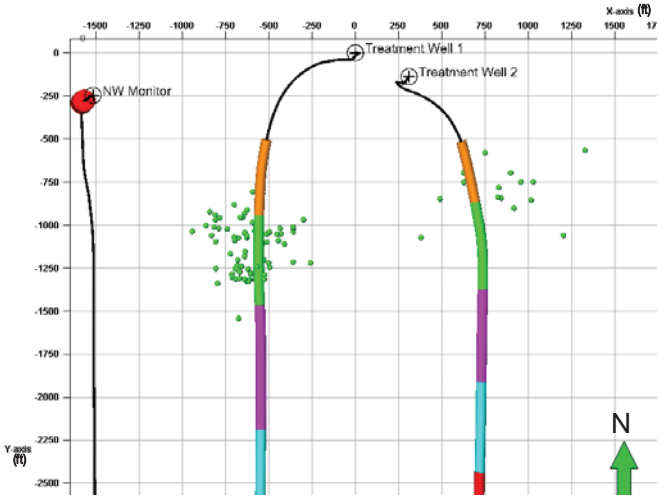

Figure 14A – Stage 6 microseismic activity from Wells 1 & 2 early in the treatment when near-wellbore pressures are high.

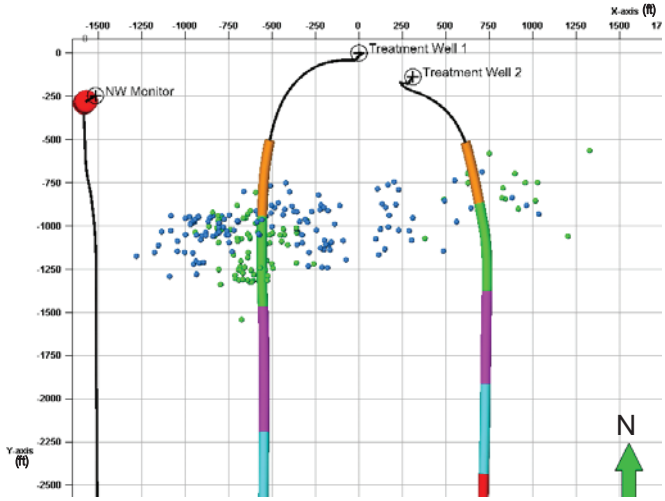

Figure 14B – Stage 6 microseismic activity from Wells 1 & 2 as the hydraulic fractures merge.

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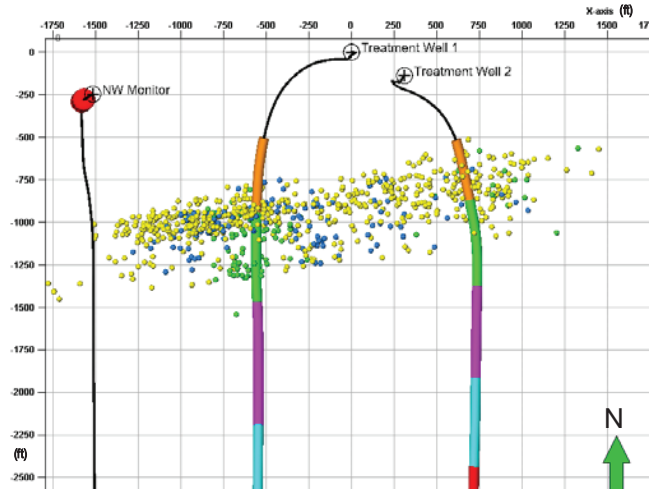

Figure 14C – Stage 6 microseismic activity from Wells 1 & 2 after the fracture systems have begun to interact with each other. Assymetric growth towards the producing (shut in for monitoring) well to the west has begun.

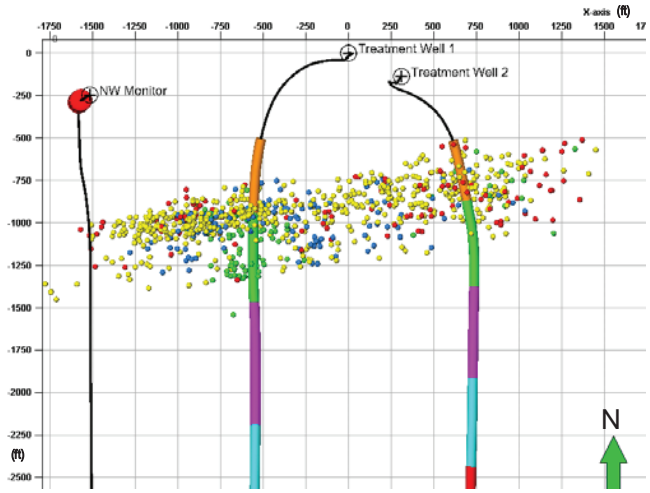

Figure 14D – Stage 6 microseismic activity from Wells 1 & 2 at the conclusion of the stage. Growth towards the producing (shut in for monitoring) well to the west is evident. Easterly growth is constrained by the stimulation treatment in Well 3 to the east.

indicating that the stress contrast is great enough to prevent height growth from being a pressure relief mechanism. Microseismic event density and event count within the region associated with Treatment Well 2's stimulation treatment increases after the two patterns of microseismic events meet.

Examination of surface treating pressure and calculated bottom-hole pressure (BHP) trends, including near wellbore pressure, show little difference in behavior between simultaneously fractured wells and similarly completed offset single wells. Simultaneously fractured wells sometimes show slightly higher calculated BHP than offset single wells. Simultaneous fracturing does not show a tendency to pressure up the reservoir and well systems more than single well treatments. Likewise, as individual well stage treatments overlap into each other, as evidenced by microseismic data, there is no significant increase (or decrease) in BHP as the completion progresses along the lateral. Wells confined in the center of the simultaneously fractured wells, between other stimulation wells without an adjacent offset producer did not develop any higher BHP than wells on the exterior with exposure and contact with offset producer wells and the producer well fracture networks. From these observations we conclude that fracture pressure response is not diagnostic in determining the degree of fracture complexity in this environment.

The perforations in both monitor wells were isolated underneath bridge plugs during microseismic monitoring. Memory pressure gauges were deployed underneath the bridge plugs to record static pressure in the laterals during the stimulation project. Previous field experience has shown that it was possible to kill an adjacent producing well while stimulating a new offset well. Pressure increases were recorded by the gauges in both monitor wells and generally coincided with the microseismic activity indicating when the fractures were extending past the existing laterals. The first and largest increases in static pressure were recorded during stage 4 and confirmed the microseismic interpretation that fractures were extending past the existing laterals during this stage.

Production data from Project 1, including the offset wells, is shown in Figure 15 and Table 1. The production plot has the average gas rates and cumulative production averages for the simultaneously fractured and individually fractured wells. Initial production rates, based on the first 7 days peak production, are higher for the simultaneously fractured wells than for the single well treatments on both

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leases. The initial rates were increased by 20% on the west side and by 72% on the east side. Thirty day daily averages are lower on the west side, but higher on the east side, for the simultaneously fractured wells. Initial rates appear benefit from simultaneous stimulation but in this case long term productivity does not appear to be impacted.

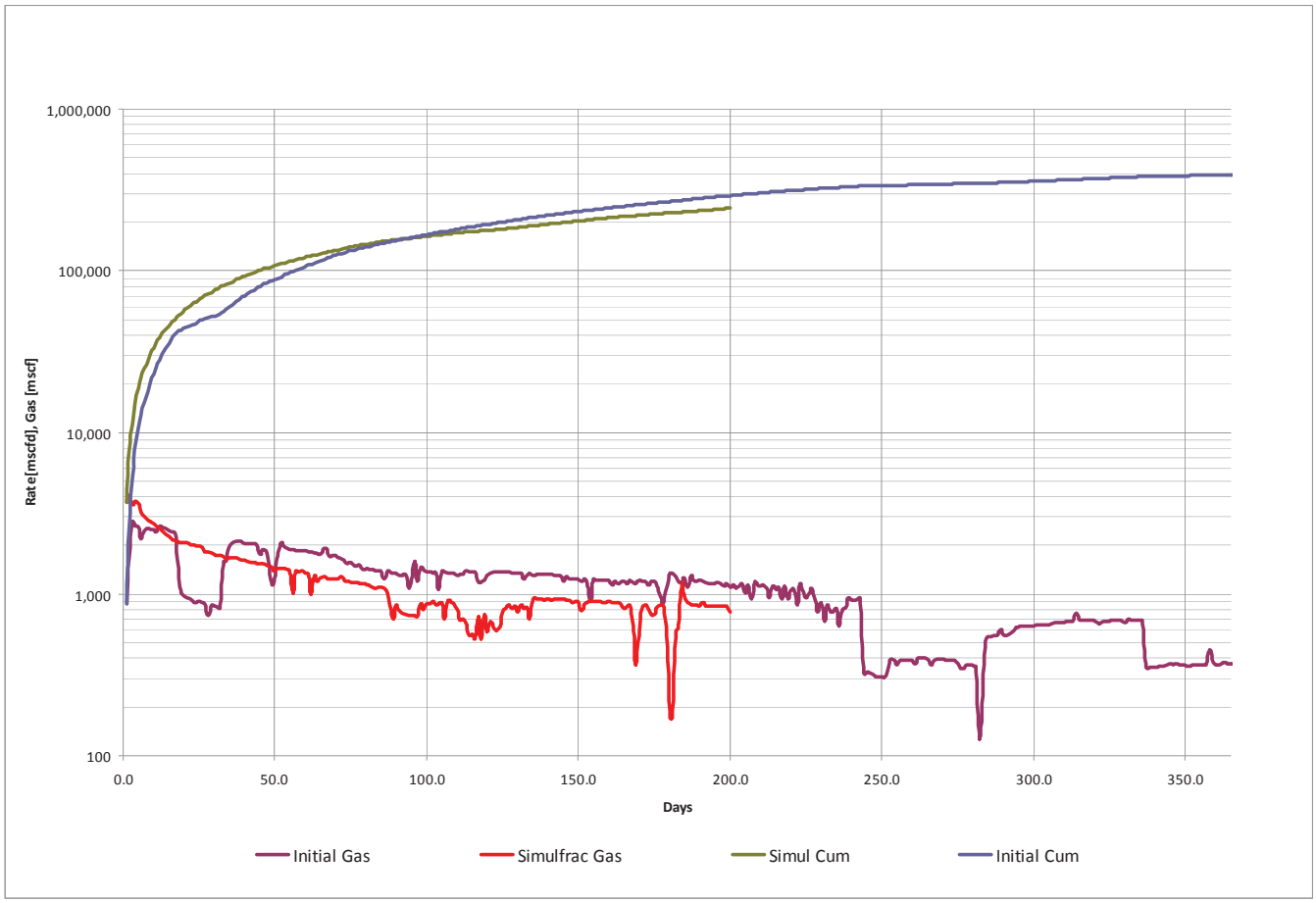

Figure 15 – Project 1 average gas rate and cumulative production for the Initial Wells (single completion) and the simultaneously fractured wells.

Example 2:

A second project was performed on four wells in one 640 acre section. Figure 16 shows the surface layout of the project. The local geology was similar to that in Example 1, with vertical depths of 7,200 ft to 7,500 ft and the lateral landed in the Woodford A with some sections extending into the Woodford B. Faults striking N45E and N60E intersect the project area and cut the well trajectories.

Example 2 area perforation and stimulation design:

- Frac stages every 500 foot of lateral, with 9 frac stages per well
- Six perforation clusters per frac stage, spaced approximately 75 ft apart
- Fluid volumes of 11,000 bbls of Slickwater per frac stage
- 100 mesh sand volume of 67,000 lbs per stage
- 30/50 mesh sand volume of 250,000 lbs per stage
- Injection rate of 95 bpm
- One re-fracture treatment, pumped prior to the simultaneous stimulation treatments
- A total of 13 of 18 simultaneous stages pumped to completion on two wells
- A single well completion with all of the 9 stages pumped to completion following the simultaneous fracs

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- All wells flowed back and put on production together

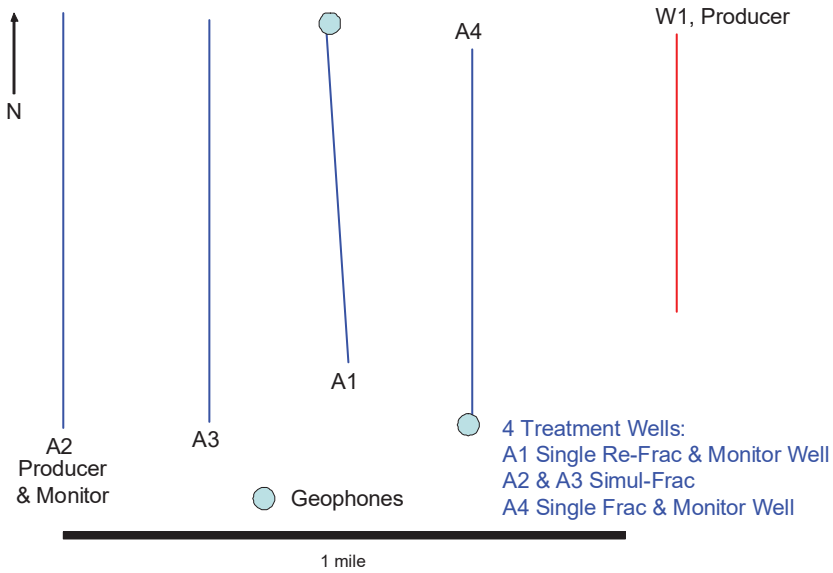

Figure 16 – Layout of the horizontal wells in the Example 2 area. A refrac was performed in Well A1 (A4 & W1 Monitoring Wells), then simultaneous stimulations performed in Wells A2 & A3 (A1 Monitoring Well). Well A4 was then fracced with A1 and W4 as the monitoring wells.

The A1 well was initially completed in May, 2007. Microseismic activity indicated that complex fracturing was present in the first two stages at the south end of the lateral (Figure 17). The A2, A3 and A4 wells were then drilled. Prior to the completion of these wells the A1 was refracced to provide a pressurized system to counter the hydraulic fractures from the new offset wells. The stimulation treatment on the A1 was again monitored with real time microseismic and again indicated complex fractures in the south end of the lateral and more planar fractures in the heel. A fracture azimuth of N70E was determined from the initial frac and refrac treatments.

The A2 and A3 simultaneous treatments used real-time microseismic monitoring to determine the dominant induced fracture orientation in order to maximize the interference between simultaneous fractures. Because of the N70E hydraulic fracture azimuth the A3 Stage 1 was performed ahead of the A2 Stage 1. Real-time microseismic confirmed the expected orientation and subsequent stages were planned accordingly.

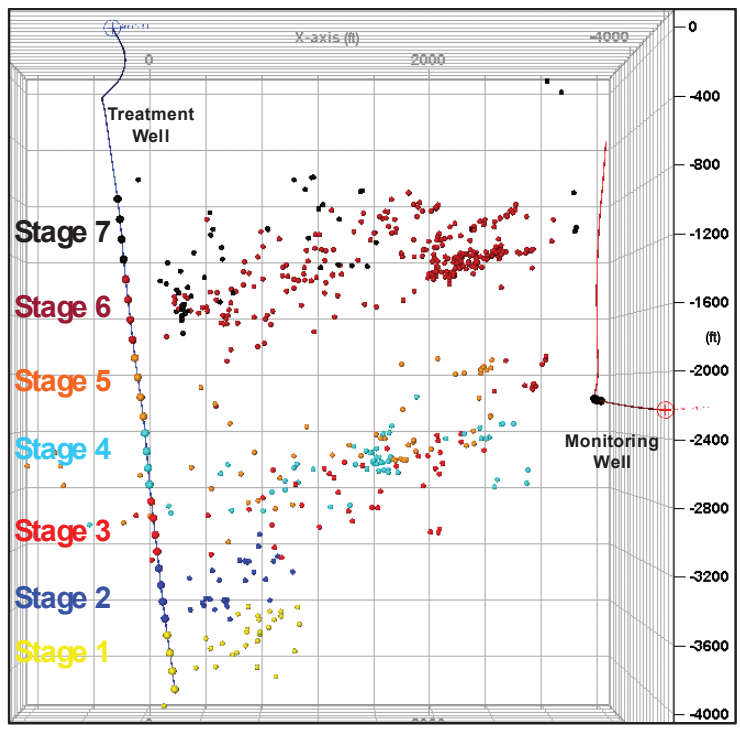

Figure 17 – Microseismic activity from the refrac of well A1. A N70E fracture azimuth was determined from this data.

The microseismic data from all stages in wells A2 and A3 is shown in Figure 18. The number of events recorded during the first four stages was limited by the distance to the monitoring well. Evidence of interaction between fractures can be inferred, but not directly demonstrated due to the lack of microseismic events from the A2 well. Some stages show extension to the east, away from the region of

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presumed fracture interference, as was seen in the previous example. Easterly extension of some stages was well past the A1 lateral

Finally, a nine stage stimulation treatment was performed on the A4 well to the east. Wells A1, A2 and A3 remained shut in following their stimulations while the A4 was completed. The microseismic activity for this well is shown in Figure 19. The microseismic activity in the toe section of this lateral is much more reliable than that recorded during the A2 and A3 stimulations because two wells were used to monitor the events during this stimulation, one of them being much closer to the south end of the lateral.

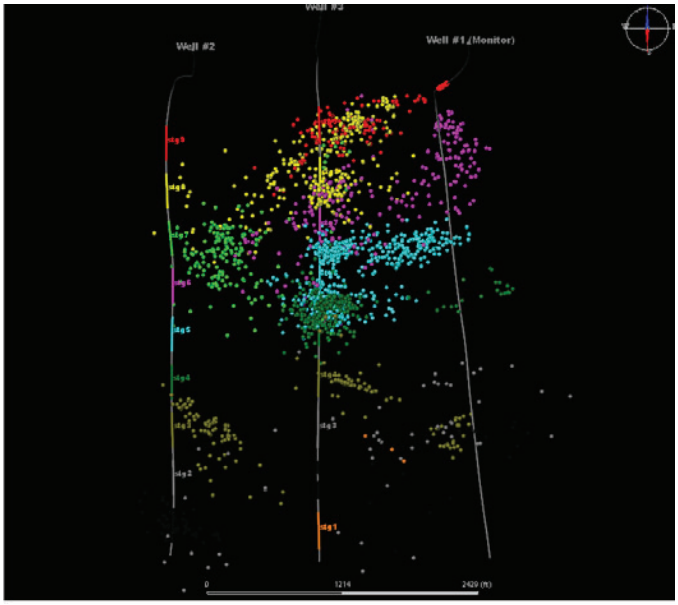

Figure 18 – Microseismic activity from the fracs on wells A2 & A3.

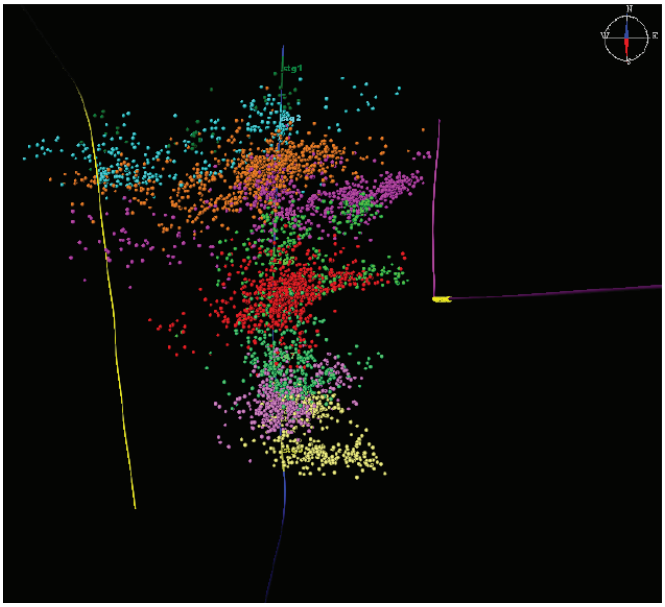

Figure 19 – Microseismic activity from the fracs on the A4 well.

As with the stimulation treatments on the A1 well where the microseismic activity is reliable in the south section of the lateral, complex fracturing with short fracture half lengths was seen at the toe of this lateral. A review of the seismic data indicates that a fault runs SW to NE through this section of the reservoir. This fault is identified in the horizontal Gamma Ray logs when interpreted and correlated to the vertical well offsets. It appears that Woodford structure is again playing a significant role in the geometry and complexity of the created hydraulic fracture systems.

Production data from Project 2 is shown in Figure 20 and Table 2. Initial production rates, based on the first 7 days peak production, are more than double those of the original individually fractured wells but slightly lower than the single well completion performed during the same job. However, the two wells that were simultaneously treated were knocked off line by an offset operator's fracture treatments for approximately two weeks within their first 45 days of production. The production rate from well A4, the single well stimulated immediately after the simultaneous fracture treatment and last well stimulated, exceeded all the rest. The 30 day daily averages increase from west to east in the new completions and are double those of the original wells, with the 60 day averages being 180% of the original wells. The average cumulative gas production is 188%, 170% and 166% at 30, 60 and 90 days respectfully. There are minor variances in the lateral lengths, number of stages and perforation clusters per well, but these factors are considered insignificant to the results.

Example 3:

Project three includes six horizontal treatment wells drilled among three existing producing horizontal

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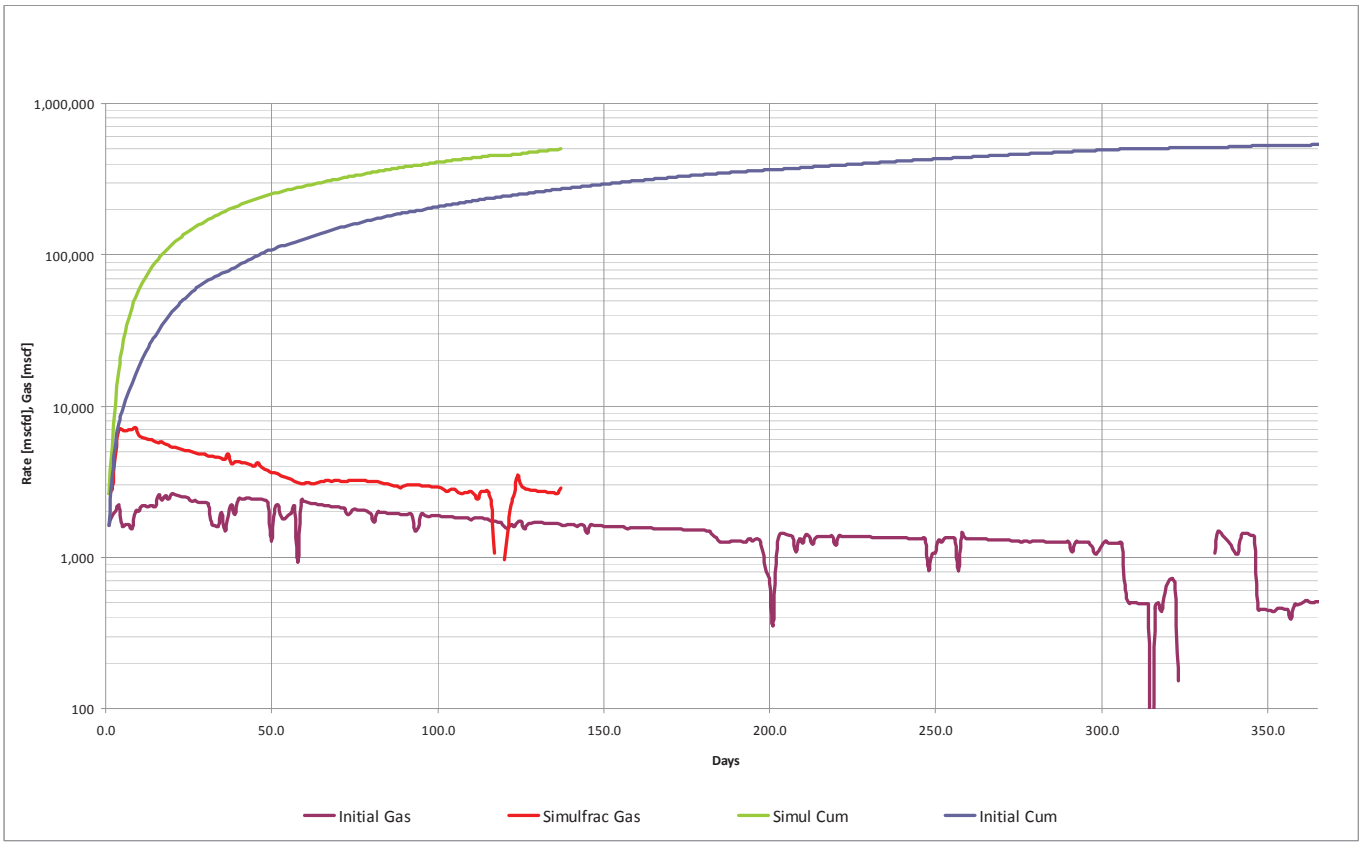

Figure 20 – Project 2 average gas rate and cumulative production for the single well completions and the offsetting simultaneously fractured wells.

wells on two and one half 640 acre sections. Wells were treated in pairs, working from the exterior of the leases towards the center, simultaneously fracturing two wells at a time. The local geology was similar to that in Examples 1 and 2 with vertical depths of 6,200 ft to 6,800 ft landed in the Woodford A with some extension down into the Woodford B. Faults striking N45E and N30E intersect the project area and cut the well trajectories. Figure 21 shows the surface layout.

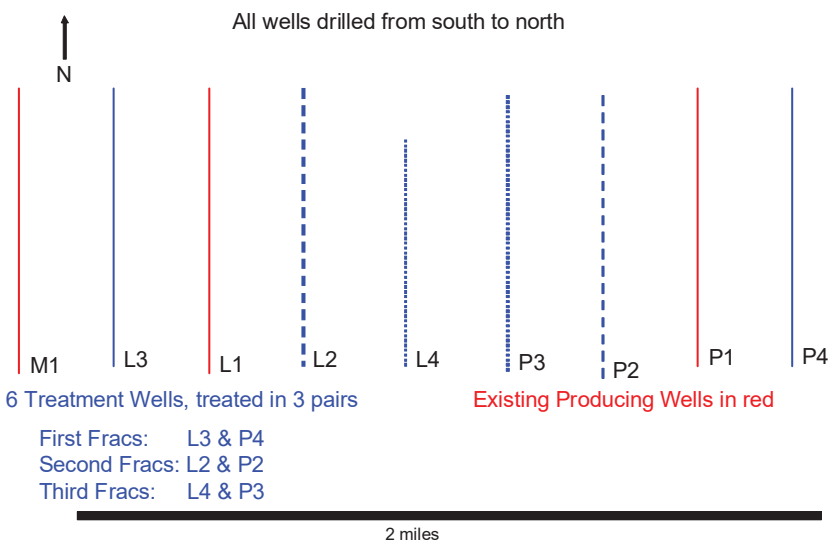

Figure 21 – Layout of the horizontal wells in the Example 3 area. Three existing wells (M1, L1 & P1) were surrounded by 6 infill wells. The new wells were stimulated in pairs starting from the outside and working inward.

Example 3 area perforation and stimulation design:

- Frac stages every 500 ft along the lateral, with 9 stage per well except 8 stages in the L4 well
- Six perforation clusters per frac stage, spaced approximately 75 ft apart
- Fluid volumes of 10,000 bbls of Slickwater per frac stage

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- 100 mesh sand volume of 33,000 lbs/stage
- 30/50 mesh sand volume of 300,000 lbs per stage on the L2, L3, and L4
- 30/50 mesh sand volume of 200,000 lbs per stage followed by 100,000 lbs 20/40 mesh sand per stage on the P2, P3 and P4
- Injection rate of 95 bpm
- A total of 48 of 53 frac stages pumped to completion
- No microseismic data was acquired due to the lack of suitable monitoring wells
- Surface pressure gauges were placed on the offset wells waiting to be stimulation with perforations already placed in the toe sections

During the first pair of simultaneous treatments, surface pressure on offset producing wells was not useful to determine the induced frac azimuth orientation. Even though the surface pressure changed, there was no way to determine what perforations along the lateral were most affected. There was no pressure response from the toes of the new wells waiting to be treated. Even though the fracture azimuth was anticipated to be east - west these wells were too far from the treatment wells to exhibit a pressure response. During the second pair of simultaneous treatments, the two inner wells waiting on fracs with open toe perforations did prove useful in confirming the anticipated east to west oriented frac azimuth. Surface pressures changed the greatest while stimulating directly to the east and west, and the change diminished as the treatments progressed back along the lateral. This confirmed the east-west orientation anticipated from prior microseismic data from Project 1.

As in the prior examples, fracture pressure interpretation was very difficult due to the high level of near wellbore pressure. Overall, there were no trends of surface pressure, calculated BHP, or ISIP moving from toe to heel in the wells. There was a general trend of increasing surface pressure and calculated BHP as the project moved from exterior to interior located wells, the exception being the P4 well, which had the highest pressures, has the greatest vertical depth, and is the eastern most well. Our observation has been that wells on the east end the field treat at somewhat higher pressures. These trends show greater pressure is developed when treating the interior wells that are confined by recent or simultaneously treated wells and not exposed to the lower pressures associated with producers on either side.

The limited production data from these recently completed wells is shown in Figure 22 and Table 4. Actual well productivity from this project is better than shown because gas pipeline curtailment is forcing the wells to be produced at relatively high flowing tubing pressures. The highest early production rates are from the interior wells that were simultaneously treated on increasingly closer spacing. The exception is the M1 well, which was the first producer in the nine section area and not in communication with any offset wells at the time of completion. On the east side (P wells), the highest early gas rate is from the most interior well. It is probable, but not conclusive that the simultaneous stimulation process boosted early production rates in this area. As in prior examples, one of the principle benefits is avoiding the workover and lifting costs of restoring lost production by fracturing into producing offset wells, as well as the fractional gas rate usually lost when wells are killed.

Summary

The bottomhole fracturing pressures have not consistently increased as the wells are being completed from the toe to the heel of the lateral. Likewise, there has been no significant bottomhole pressure increases associated with the simultaneous fracturing process. There has also not been a consistent and measurable bottomhole treating pressure increase from exterior wells to interior wells during multi-well simultaneous fracturing operations. Nonetheless, the simultaneous fracturing process has enhanced production within the production periods examined on two of the three projects, with the third project wells not yet not flowing at full potential.

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There are also operational benefits when developing acreage with simultaneous hydraulic fracturing. In many cases, conventional fracturing of horizontal wells within this field has resulted in watering out of offset producers that no longer have the energy to unload significant quantities of fracturing fluid. The resulting drop in gas rate is likely due to fluid invasion of the fracture systems on existing producers. Production may also be impacted by fluid imbibition into the lower pressured reservoir at the fracture face. It is also possible that fines production and migration may be degrading fracture conductivity. In some cases, gas production rate can be restored to the previously established trend. Even so, in this best case scenario there is still lost gas that has not been produced during the down time required to reestablish production (Figure 23).

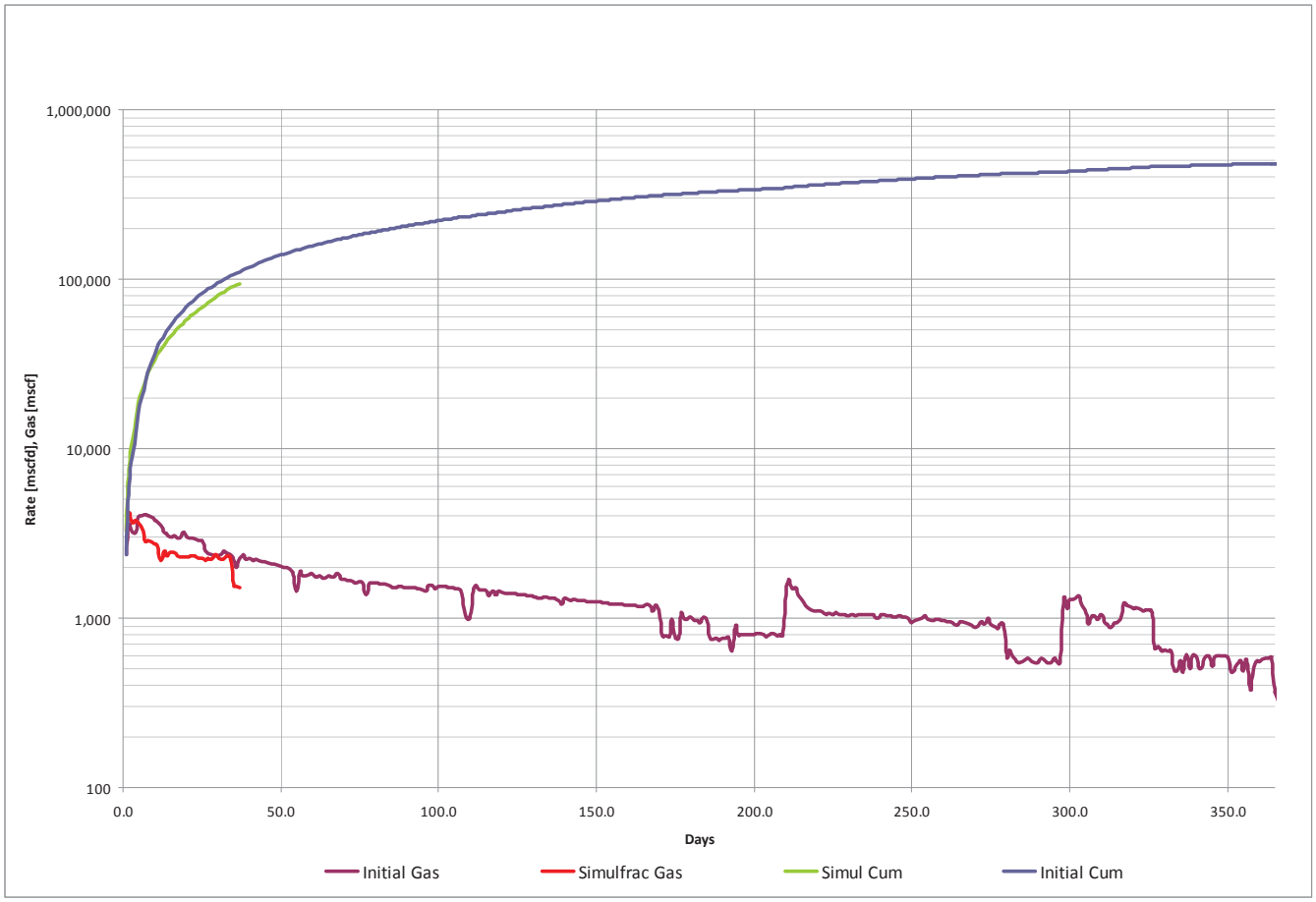

Figure 22 – Project 3 average gas rate and cumulative production for the single well completions and the offsetting simultaneously fractured wells.

Once an economical area is identified, drilling and completing multiple wells simultaneously enables an operator to develop the area without hampering producing wells. This will save the costs of well work and water removal operations on offset producing wells. Wells can also be completed in a shorter period of time. Also, by simultaneously treating a group of wells the operator can ultimately produce more gas by improving the field development processes to minimize production interruptions, workovers, and produced water lifting requirements.

Conclusions

- Simultaneous fracturing has increased initial production rates in two of the three projects. In the area that initial production was not improved, pipeline constraints could not handle the full capacity of the wells. Also, early data indicates probable long term production rate improvement in the projects with improved initial production.

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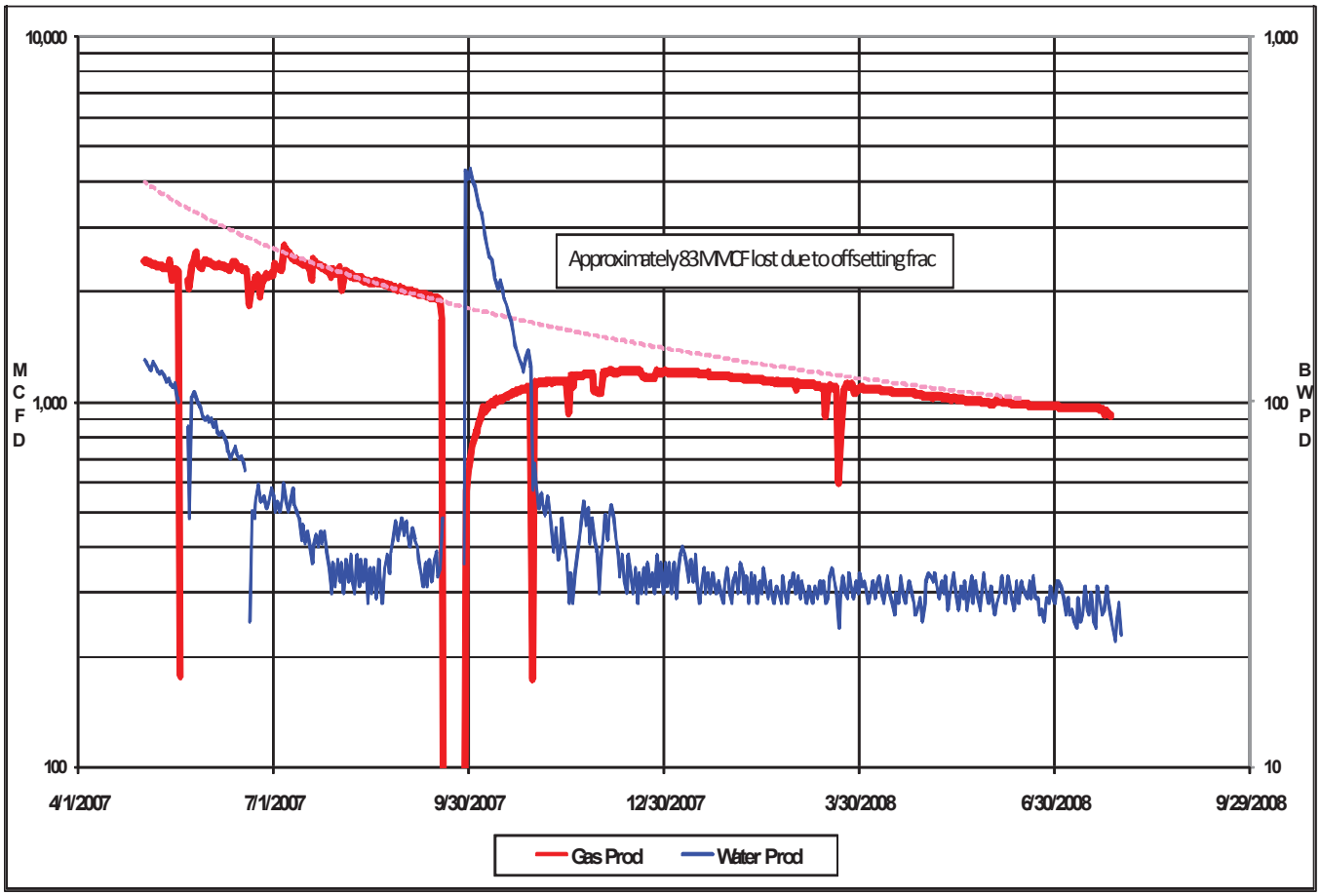

Figure 23 – Gas rate recovery of an existing well after being impacted by the stimulation process on an infill well noting required for production to recover and the associated lost gas

- Simultaneous fracturing avoids the loss of production in existing wells and the costs associated with restoring production. The required workover and/or lifting operations costs from $100,000 to $300,000 depending on the severity of the problem.
- Simultaneously fractured wells sometimes have higher fracturing surface pressures, calculated bottom-hole pressures, and ISIPs than offset wells treated alone. This pressure trend is inconsistent and not considered diagnostic in the effectiveness of simultaneous stimulations.
- Because of the lack of bottomhole pressure build during stimulation it is anticipated that the hydraulic fracture spacing is on the order of 10s of feet. The spacing is thought to be close enough to be within the resolution of microseismic. This close spacing is possible because of the relatively low Young's Modulus and the low fracturing fluid viscosity to prevent significant Net Pressure build.
- Microseismic technology confirmed the direction of induced fracture propagation. This insured that fracturing stages were appropriately executed to increase the odds of interference of opposing hydraulic fractures. Microseismic data also indicated that most induced fractures are complex and usually are well contained within the Woodford. Structural features have also been shown to impact hydraulic fracture geometry. Occurrences of microseismic events out of zone or with relatively high length to width ratios are usually associated with faults.
- When opposing fractures overlap, increased microseismic activity occurs closer to the wellbore, or on the far side of the lateral when no offsetting fracture is propagating, not in the region of fracture overlap. The higher shear stress near the fracture tips may be terminating extension of fractures in close proximity to each other. Microseismic activity is also frequently seen axially

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towards the heel of the lateral in this environment. Height growth was not observed other than where structurally influenced. This fracture geometry indicates that the horizontal stress contrast is great enough to prevent fracture height growth but the bottomhole treating pressures are high enough to dilate natural fractures normal to the preferred fracture plane.

- Bottomhole or surface pressure gauges on offset wells can be used to approximate offset induced fracture azimuth if a limited number of perforations are exposed at a known location.
- Geologic structure can impact the geometry of the created fracture systems. Example 2 showed that short, complex fractures were present on one side of a fault and longer, more planar fractures were generated on the other side of the fault.

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Appendix

Project 1		East Side			West Side		
Well		H1	H2	H3	W1	W2	W3
Status		Producer	Treatment	Treatment	Producer	Treatment	Treatment
Stimulated		Single	Simul	Simul	Single	Simul	Simul
Frac Stages		6	6	7	8	5	7
Location		West	Interior	Exterior	East	Interior	Exterior
DOFP		5/10/2007	4/27/2008	4/27/2008	8/11/2007	4/25/2008	4/25/2008
IP-7day avg	mscfd	2,331	3,757	4,299	3,091	3,642	3,793
30 day avg	mscfd	2,155	2,738	2,976	2,616	1,437	2,054
150 day avg	mscfd	910	960	926	1,393	877	815
30 day cum	mscf	61,276	82,155	89,269	78,455	65,891	61,630
90 day cum	mscf	140,086	166,273	171,346	172,733	138,399	142,683
120 day cum	mscf	168,599	192,701	183,260	222,591	164,410	171,180
150 day cum	mscf	196,868	221,796	208,695	275,641	190,928	196,620
Water 150 day	bbl	31,981	44,806	45,739	100,439	23,271	45,844

Table 1 – Project 1 completion and production data

Project 2						
Well		A1	A2	A3	A4	W1
Status		Producer	Treatment	Treatment	Treatment	Producer
Stimulated		Original Single w/ re-Frac	Simul	Simul	New Single	Original Single
Frac Stages		7	9	9	9	5
Location		Interior E	Exterior W	Interior W	Exterior E	E of A4
DOFP		6/25/2007	6/29/2008	6/27/2008	6/27/2008	7/1/2006
IP-7day avg	mscfd	3446	6380	7230	7102	2613
30 day avg	mscfd	3523	5137	5734	6195	1142
90 day daily	mscfd	2044	2536	2613	3810	1289
30 day	mscf	108683	154099	173013	186861	73812
60 day	mscf	196900	210134	256494	326199	113666
90 day	mscf	282235	291193	342951	445752	152029
120 day	mscf	351859				188297
150 day	mscf	416042				223937
Water, total	bbl	60153	74095	80837	57033	46957

Table 2 – Project 2 completion and production data

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Project 3		West Side				
Well		M1	L1	L2	L3	L4
Status		Producer	Producer	Treatment	Treatment	Treatment
Stimulated		Single	Single	Simul	Simul	Simul
Frac Stages		7	7	9	9	8
Location		West Side	Exterior	Exterior	Exterior	Interior
DOFP		4/1/2007	10/1/2007	10/1/2008	10/1/2008	10/1/2008
IP-7day avg	mmscfd	3.1	2.1	2.5	2.0	2.9

Project 3		East Side			
Well		P1	P2	P3	P4
Status		Producer	Treatment	Treatment	Treatment
Stimualted		Single	Simul	Simul	Simul
Frac Stages		7	9	9	9
Location		East Side	Exterior	Interior	Exterior
DOFP		7/1/2007	10/1/2008	10/1/2008	10/1/2008
IP-7day avg	mmscfd	2.4	1.8	3.3	3.1

Table 3 – Project 3 completion and production data

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