

Shale Gas Well Completions and Maximizing Gas Recoveries

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Abstract

It is shown that stress fields within the earth are the principle control for hydraulic fracture direction in horizontal shale gas wells. Hydraulic fracturing is a process of increasing permeability within gas shales and involves a sophisticated organization of technology, good planning and proper management of equipment over a very short time period to be successful. The direction and extent of the induced fractures can be determined in near real-time at the well site via application of earthquake seismology theory in a now common process known as frac mapping. Next to the horizontal lateral azimuth, the total volume of slurry pumped into the well is a major factor in determining well EURs. Vertical fracture growth can be controlled and is important in concentration of the slurry within the main zone target zone that has the high TOC and porosity. Cemented casing with perforations is currently the most used method for zone isolation. New open-hole sleeve packers may eventually provide more flexibility in fracture design while also providing a means for refracturing multi-stage fractured horizontal wells, a technique not now commonly available. Multi-Stage fracture design requires incorporating rock properties with fracturing effect simulations and then verifying results using 3D reservoir simulations. Maximizing the gas recovery factors and EURs can be accomplished through use of closely spaced laterals with inter-fingered fracture stages and exploiting the stress shadow fracturing phenomenon. Even greater EURs may be possible if the wells can be refractured thereby opening up additional permeability channels. Shale gas development has progressed in an environmentally sensitive manner within the U.S. and will continue in this manner. During the past ten years, all of these technologies have been either newly developed or were the advancement of existing technology with modifications. The opportunity exists to take these proven technologies to other areas of the world for exploitation of shale gas reservoirs.

Introduction

In the prior papers in this series we saw that gas shales are actually mudstones that have very low permeability, high organic content and are thermally mature. We also saw that these rocks—as do most mudstones—contain a significant amount of silt sized particles (usually quartz). It is this silty component that provides the porosity for the free gas and the volume for high early production rates. A large component of the available gas is also bound within the organic matter and to the clay platelets. This bound gas will be slowly produced through time by adsorption. The several order-of-magnitude increase in permeability required for economic production of the free and adsorbed gas is provided by the application of high volume, multi-stage hydraulic fracturing.

Published Gas-In-Place values for shale gas plays typically range from 50 Bcf per square mile to over 300 Bcf per square mile and are in constant flux.

Recovery factors have historically been conservative and usually no more than 15%. However, new well spacing and completion designs are in development that can potentially triple the current recovery factors. However, all gas shales are not the same as we have seen. Each gas shale play will require specific experimentation to find the optimum well spacing and completion plans to maximize gas recovery.

Planning for the well completion actually begins with planning the azimuth of the horizontal well as this heavily influences the effectiveness of the hydraulic fracturing. The subsurface stress field may be very complex but it is formed based on well understood principles of rock mechanics as will be shown below.

Influence of Earth Stress Fields on Hydraulic Fracture Propagation

It is the objective of hydraulic fracturing to initiate new (or reactivate existing) vertical fractures within the gas shale to improve permeability nearby and away from the wellbore. Initially, vertical wells were drilled in gas shales and fractured with single, large volume slick water fractures. Gas recoveries were low, in large part due to the limited potential reservoir length (only a few hundred feet) to contact. With multiple hydraulic fracture stages in horizontal wells, several thousand linear feet and 100,000s of square feet of surface area of potential reservoir could be exposed greatly increasing potential gas recovery. This concept is illustrated in Figure 1. For a thorough treatment of this topic see Cosgrove and Engelder, 2004.

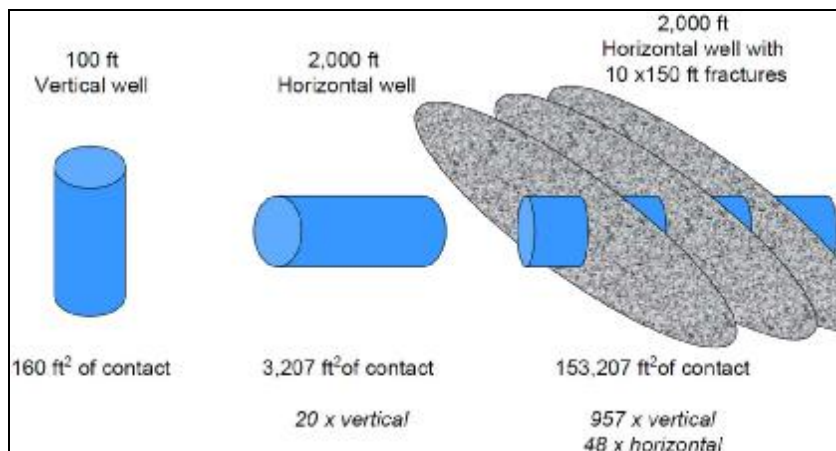


Figure 1: Comparison of vertical well versus horizontal well reservoir fracture surface area contact (Themig, 2008).

The induced fractures in horizontal wells expose large areas of the shale allowing gas to flow from the porosity, by adsorption and by connectivity to open existing tectonic fractures. Figure 2 illustrates this concept. Here the horizontal wellbore in white was drilled from left to right. Only one side of the hydraulic fracture “half-widths” or “half-wings” are displayed along the wellbore. In this case there are 10 fractures or “stages” shown. These fractures can propagate vertical heights of over 600 feet and effective horizontal drainage distances of up to 700 feet, dependant on a number of factors.

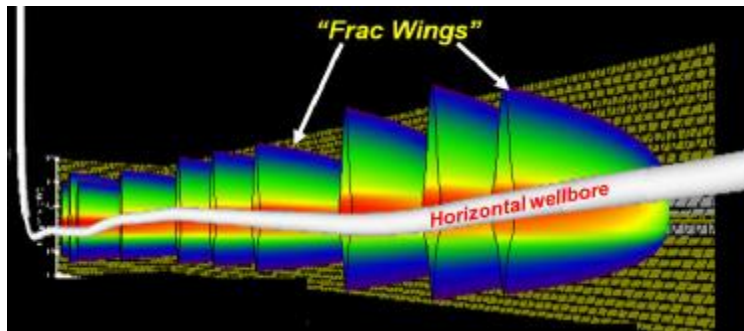


Figure 2: Horizontal wellbore with 10 induced fracture "half-wings" ~400-700 ft (Griffin, 2006).

Fracture Orientation and Geometry

The maximum productivity of hydraulic fracturing is usually obtained when the induced fractures form normal to the wellbore, minimizing the tortuosity of near wellbore flow regimes and allowing maximum fracture areal propagation and drainage. The direction of this fracture propagation is influenced by the tectonic and regional stress fields. Tectonic fractures are those whose origin can, on the basis of orientation, distribution, and morphology, be attributed to or associated with a local tectonic event. Tectonic fractures form in networks with specific spatial relationships to folds and faults. Regional fractures on the other hand, are those that are developed over large areas of the earth's crust with relatively little change in orientation, show no offset across the fracture plane, and are always perpendicular to major bedding surfaces. Regional fractures are different from tectonic fractures in that they are developed in a consistent and simple geometry, have a relatively large spacing, and are developed over an extremely large area crosscutting local structures (modified from Nelson, 2001). Regional stress fields within sedimentary basins exist for long periods of geologic time and are modified through time dependant on the distribution of local tectonic forces acting within the basin. Over time there may have been different directions of local stress resulting in different tectonic fracture directions preserved within the sedimentary sequence.

It is these local tectonic stress fields that probably have most impact on the orientation of our induced hydraulic fractures. However, the older regional fractures may still be open or can be filled. Hydraulically induced fractures in a horizontal wellbore will propagate in the direction parallel to the current maximum horizontal stress (MxHS). This is a basic tenet of rock mechanics. Figure 3 illustrates this principle. The horizontal wellbore parallel to the MxHS has induced fractures that parallel (are longitudinal to) the wellbore while the wellbore normal to the MxHS has induced fractures normal (transverse) to the wellbore and parallel to the regional stress. The tranverse fractures have the best chance of effective flow and areal drainage.

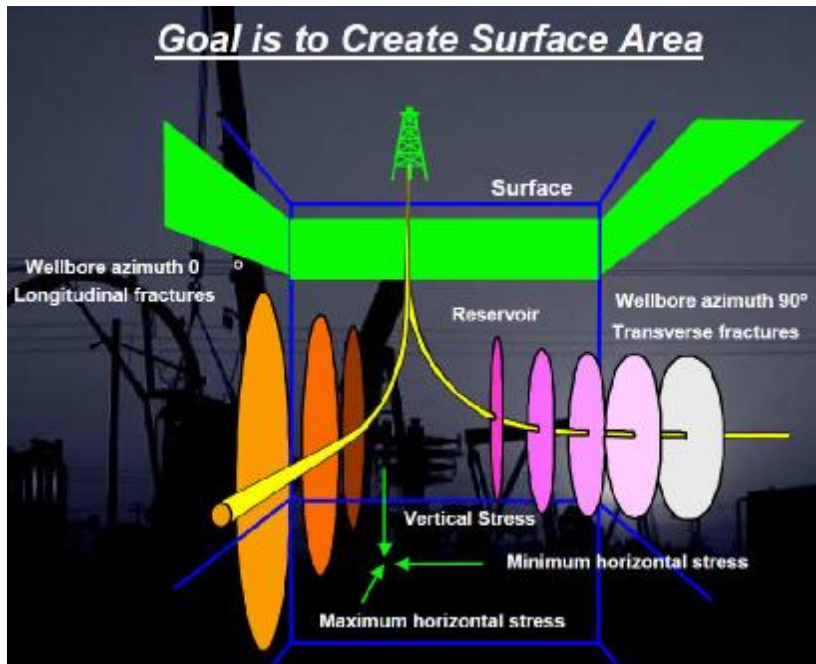


Figure 3: Hydraulic fracture orientation versus horizontal well azimuth (Downey, 2008).

Figure 4 is a result of modeled induced fracture azimuths of horizontal wells based on stress orientation. It shows the impact on areal drainage when the horizontal wellbore orientation varies with respect to the MxHS. All wells have the same effective lateral length and fracture stimulations. The well to the left was drilled parallel to the MxHS resulting in longitudinal induced fractures and complicated (poor) areal drainage. The well on the right drilled normal to the MxHS resulting in fractures transverse to the horizontal wellbore maximizing areal drainage. The example in the middle is an intermediate result.

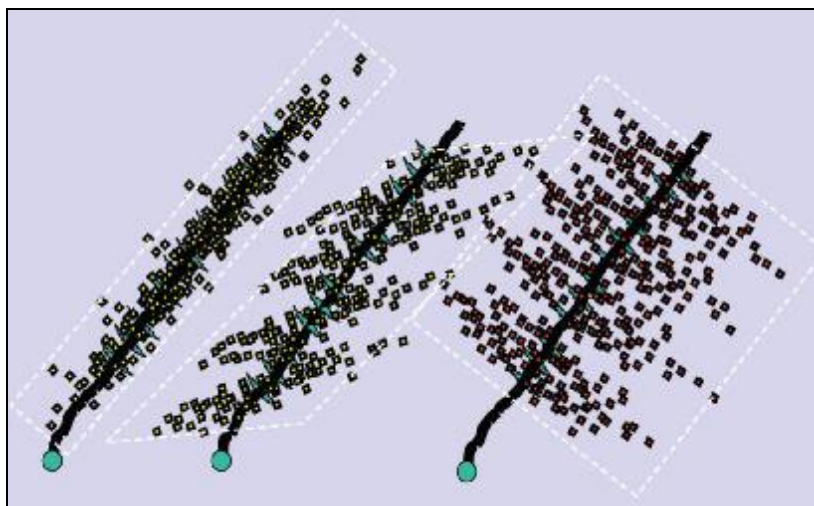


Figure 4: Impact of lateral orientation. Map view of fracture azimuth simulation for horizontal wells drilled at varying angles to MxHS (Mayerhofer, 2009).

These relationships are common in actual wells as shown in Appendix 1. This shows fracture mapping of two wells. The rose diagram in the upper right hand corner shows the natural fracture azimuths (and MxHS direction) as determined by interpretation of a Formation Micro Imager log of a vertical well nearby. The horizontal wellbore on the left (transverse) is oriented normal to the MxHS and the resulting induced fractures appear simple and near normal to the wellbore as expected. The horizontal well on the right (longitudinal) is oriented parallel to the MxHS with the induced fractures being complexly oriented near the wellbore and become more parallel to the MxHS farther from the wellbore. Near wellbore flow tortuosity (with probable lower production rates) is far greater in the well on the right when compared to the well on the left.

Application in North America

Several of the shale gas plays within North America are related to the Late Paleozoic Appalachian-Ouachita tectonic belt that stretches across the southern and eastern United States. This would generate a regional fracture system with the complex overthrust faulting setting up different local tectonic stress regimes generally controlling the direction of hydraulic induced fractures. These fracture patterns must be evaluated based on subsurface data and surface geology. Examples of real fracture complexity are shown in Appendix 2 and 3. Appendix 2 shows photos of surface fracture patterns. The Colorado example is a simple pattern with near normal conjugate fracture intersections suggestive of regional stresses. The Oklahoma example is more complicated with several overlapping fracture patterns suggested. This fracture pattern may also have a local tectonic component as well. Appendix 3 is the same as Appendix 2 except the traces of the fractures have been highlighted. The older regional fractures can be reopened to form intersecting fracture systems to the main transverse systems if there is rotation of MxHS during the fracture stage. This will be discussed in more detail later. These potential intersecting fractures can contribute significant additions to the overall permeability increase during fracturing.

Hydraulic Fracturing of Horizontal Wells

Planning the well completion and its execution is the most important stage of shale gas production. The overall success of the project is dependent on the investment in hydraulic fracturing, which may be largest as a percentage of total project investment.

Gas shales are hydraulically fractured using the "slick water, low sand" technique pioneered by the George Mitchell Company (later Devon) in 1997. This technique improved initial production rates and EURs greatly and proved to be a much less expensive process than the typical gel fracs used at the time making large scale shale gas production possible. In this process, large volumes of fresh water, ranging from 60,000 bbl to over 150,000 bbl containing small amounts of friction reducers, biocides, and scale inhibitors are mixed with 100s of tons of quartz sand proppant (or other type proppant as reservoir conditions warrant) and pumped down the 5 ½" casing into perforations. The water and proppant mixture is called the slurry. Pumping is divided into "stages" such that a single stage frac job will usually not have volumes greater than 15,000 bbl water

and 100 tons of sand. Since the water provides no buoyancy for the sand, the particle velocity, which approximates Stokes Law, is used to move the sand down the casing and into the fractures where it progressively moves away from the wellbore. Gravity then overcomes horizontal velocity and the proppant settles out similar to how sand dunes propagate via wind motion. The larger proppant is concentrated closer to the wellbore. Average pumping rates of 65 to 120 bbl per minute or more are common. This process requires thousands of hydraulic horsepower available at the well site. Hydraulic fracturing a single well with ten stages can often take a week or more.

A typical plan for a larger volume single frac stage would require 28,000 bbl and 185 tons sand (150 bbl per ton) pumped at an average rate of 75 bbl water per minute and 1.5 tons sand per minute through a 5 ½" casing with two sets of 5 ft perforations into a zone with a pressure gradient of 0.72 psi per ft and BHP = 4,200 psi. This job would require 6,400 hydraulic horsepower provided by 10 18-wheel trucks each with a 2,250 hp pump (22,500 hp total) plus several additional stand-by pump trucks. The triple amount of horsepower required is to overcome all the friction loss in the casing and the perforations. A control panel plot of the first two hours of a frac job is shown in Appendix 4. Here plots of slurry volume rate, pressure and friction reducer rate are plotted against time. The project controller can adjust the rates and pressures in real time to try to affect the desired outcome. The summary statistics for the total stage are shown on the right. A stage such as this would take six to eight hours to complete and cost about US\$140,000 including all service company charges. A 10,000 bbl frac stage would cost about US\$75,000 with prices declining at this time.

Once the last of the slurry is pumped for this fracture stage a plug is pumped down the hole (or set with coiled tubing) to isolate this fracture from the next stage. After the last stage is pumped all plugs are removed and the flow back period begins.

Hydraulic Fracture Growth Indicated by Seismic Monitoring of Hydraulic Fracturing

As has been discussed, hydraulic fractures tend to propagate according to the present day stress directions (parallel to the MxHS) and any pre-existing planes of weakness, such as natural fractures. These natural fracture systems reflect ancient and more possibly recent localized stress regimes. The growth of these fractures is often much more complex than we may envision and certainly more complex than we can currently model with any statistically predictive certainty. Appendix 5 illustrates this challenge. The central example is "a perfectly vertically contained fracture." The other examples that frame the objective fracture style represent what can occur and often do in the real world. Each fracture stage probably contains elements of each of these outcomes. The success of the fracture stage will depend on which elements predominate.

The current method of understanding fracture growth in this complex environment is by use of Passive Seismic Recording of Hydraulic Fracture Stimulation (also known as and will be referred to in this paper as "Frac Mapping" for simplicity). This seismic technique records the initiation and progression of the induced fractures in a three-dimensional sense. It is used heavily in all of the gas shale plays. There are two main methods: subsurface

monitoring and surface monitoring. We will focus on sub-surface monitoring as it is most accurate now and results are available in near real time at the well site. Appendix 6 shows the components of this technology. They are from upper left clockwise, the monitor well (which has 12 unit vertical array of three component seismometers downhole clamped to casing) and treatment well relationship, the p-wave and s-wave time difference determination, the hodagram that determines azimuth of the event location, a multi-trace seismogram showing moveout over the vertical seismometer distance for both wave field arrivals and a wireline sonic log used to construct the p-wave and s-wave velocity models for seismic travel time to depth conversion. Depending on the geometry of the shale zone and velocity contrasts there is a limiting distance between the monitor and treatment well. The following is a description of the process modified from Willis et al, 2007:

In order to determine the extent of hydraulic fracturing away from the injection well, recordings of the micro-earthquakes made by the fracturing rocks are usually collected in a nearby observation well equipped with multiple levels of three component, clamped seismometers. The arrival times of these events are picked in near real-time and the location of the fracturing is determined using standard earthquake location technologies. To determine the exact location of each fracture requires a very accurate velocity model between the reservoir and the observation well. Because this is not generally known, events are initially located using a simplified velocity model giving at least relatively accurate positions and then verified by recording the perforation shots prior to fracturing, finalizing the exact velocity model. The hydraulic fracturing design is then modified to make sure that the event locations are only occurring in the reservoir and not straying into the cap rock or the next well, for example. These events can then be co-rendered with a 3D seismic volume so that the lateral and vertical extent of fracturing can be visualized with interpretations of the reservoir unit.

These surveys are sometimes known as “Pinnacle Surveys” named for the service company that pioneered their usage within the oil and gas industry. Figure 5 shows a map view of a seismic monitor survey of a two stage hydraulic fracture in the Barnett Shale. The horizontal well runs from southeast to northwest. Stage one events are the blue dots and stage two events are red dots. Inspection suggests that the fracture distribution was not uniform although it does trend normal to the horizontal wellbore (also called a lateral). Appendix 7 is a summary by Schlumberger of the benefits of seismic frac mapping.

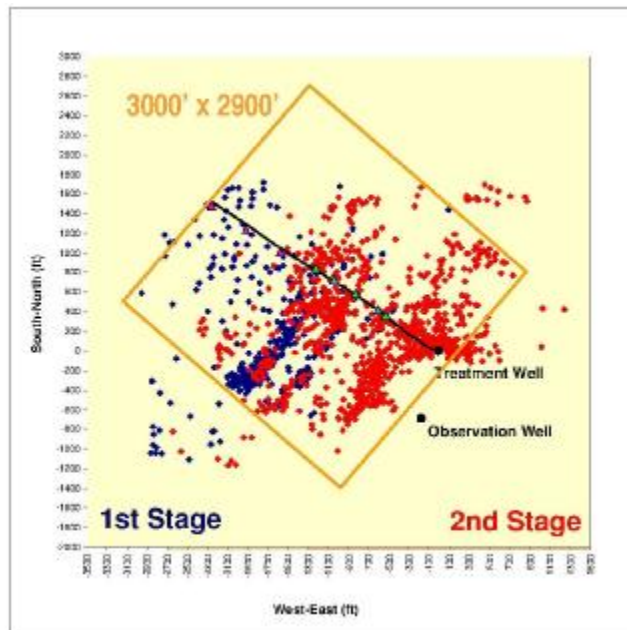


Figure 5: Map view of fracture mapping (SPE 90051, 2004).

Fracture Slurry Volumes Versus Well Productivity

The volumes of slick water and proppant (the slurry) used in the fracture completion is critical to the overall economic success of the shale gas well. There are few published in-depth studies comparing initial gas flow rates and EURs to total fracture fluid volumes. The ones that are available all point to correlations showing that higher volumes of fracture fluid put into the ground usually result in higher EURs. There are certainly other controllable factors such as well azimuth, cement job, perforating strategy, stage spacing, pump rates and proppant sizes, but fracture fluid volume in the ground usually predominates. Appendix 8 is an unpublished study of 172 horizontal wells over five counties in the Barnett Shale play in North Texas completed in 2005. This analysis linked fracture slurry volumes (water and proppant independently) and early production rates to probable economic outcomes of the wells. It implied that after taking into account the learning curves of each operator and the regional lateral variations in the gas shale production potential, the most economic wells were those that had a minimum of 65,000 bbl of slick water plus a high ratio of proppant to the slick water. Appendix 9 is a similar unpublished analysis done two years later that relates length of perforated offset (abscissa) to the EUR (ordinate). In this case the author made the assumption that the length of the perforated offset was directly related to the total fracture slurry volume. He then related that length to the well EURs. Even though this analysis is not as rigorous as the previous, it uses a different set of wells and the overall results are similar to Appendix 8. There may be disagreement between authors as to what the minimum volumes should be and why, but field results have shown us that if this total well minimum fluid volume is not obtained for whatever reason, the gas well will not have an EUR that will result in acceptable economic return. The reasons for using sub-minimum fracture fluid volumes may not be controllable, such as

individual fracture stage screen-out, nearby faulting or lack of vertical fracture barriers. The end results are usually the same for these type wells.

Controlling Vertical Fracture Growth

Controlling the height of the induced fracture is important. It is most efficient if it stays “within zone” so the majority of the slurry travels horizontally fracturing the target zone. The vertical zone as shown in Figure 6, is an example of a horizontal well in East Texas within a sand-shale sequence containing multiple reservoirs over a large vertical extent. In this case the induced fractures have height above the lateral of 420 ft and 360 ft below the lateral where a partially effective lower natural fracture barrier is present. The total fracture height is almost 800 feet. This large vertical fracture growth is preferred in vertically stacked, multiple reservoir cases such as this well; however, we would rarely want such extreme vertical growth in shale gas reservoirs.

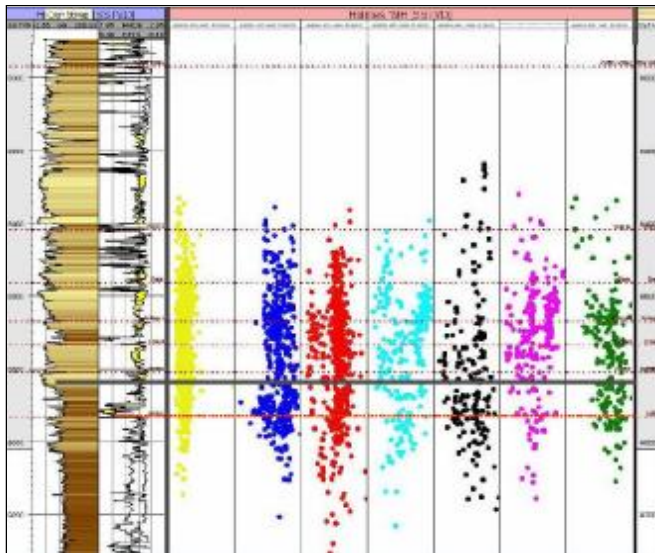


Figure 6: East Texas vertical pilot hole log with sand-shale sequence and horizontal lateral with 7 stage fracture and Passive Seismic Fracture Monitoring. Lateral depth is 8,840 ft. Induced fracture height extends 420 ft above lateral and 360 ft below. Note how lower fractures begin to die out at major sandstone-shale interface at 8975 ft. This would be a lower fracture barrier (modified from Caron, 2008).

Vertical fracture growth control can be accomplished many ways including exploitation of the geologic setting, oriented perforations, perforated length, pumping rate, proppant sizes, N₂ cavitation and stress fracturing. We'll concentrate on the main three. The first method depends on the geological setting where the gas shale target zone is located, such as the Barnett Shale in North Texas. It is encased within impermeable limestone, in this case the Forestburg limestone above and the Viola limestone below. A horizontal well is shown in Figure 7 that was drilled from right to left. Here the vertical fracture growth is limited to 300 feet, easily within the vertical extent of the Lower Barnett shale, primarily due to the limestone barriers above and below. The second method is to limit the length of the perforated zone to less than ten feet, often at five feet. Perforations are usually made at four to six shots per foot with a 60° rotation. This perforation strategy is thought to focus the initial fracturing more horizontal than vertical by limiting the options for growth. The third method is via

restraining the initial fluid pumping rate to allow the induced fractures to initiate propagation laterally instead of vertically. In most instances the MxHS is usually less than the vertical stress so the lower initial pump pressure and volume is thought to preferentially move horizontally. In application, the pump rate is increased slowly to formation breakdown (signaling fracture initiation) and then lowered to 35 bbl per minute and slowly increased again to minimize the vertical growth.

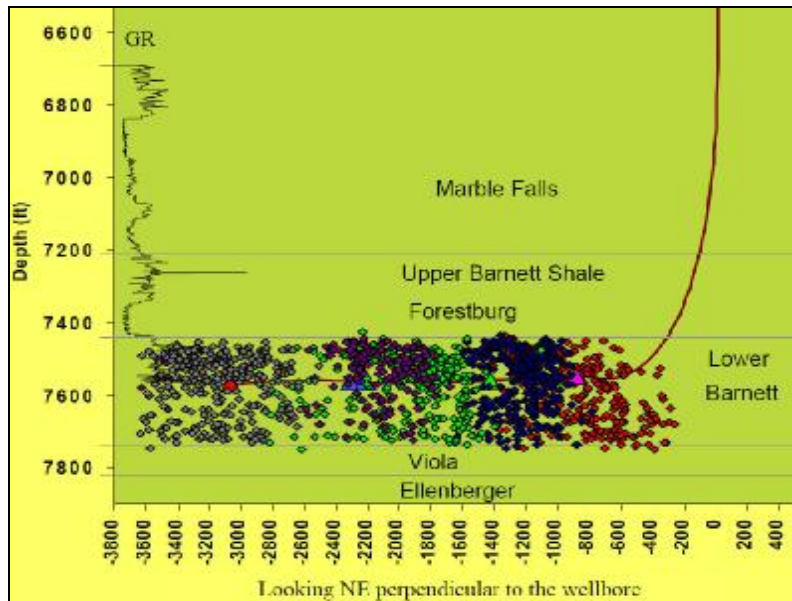


Figure 7: Side view of passive seismic hydraulic fracture monitor showing most of the Barnett Shale fracture signals are within the Forestburg - Viola Limestone Fracture barriers (Sigmon, 2008).

Casing and Liner Options

Cemented Completion

As has been mentioned in an earlier paper, most horizontal gas wells in the various shale plays in the U.S. have cemented casing set to the toe section of the lateral. This is often 5 ½" casing. A typical casing plan is shown in Appendix 10. This plan shows 5 ½" casing set from the well TD to the surface. Five fracture stages were planned for this well with three sets of 10 foot perforations spaced at 400 foot intervals. The slurry was pumped directly down the casing as is current practice. Pumping through smaller ID tubing would greatly extend stage elapsed time and considerably increase the cost. This well had test flow rates over 10 Mmcfgpd.

Over the past five years, in horizontal completion design for gas shale wells the number of fracture stages per well has increased while the number of perforations per stage has decreased. This change evolved after use of frac mapping became common. It was noticed that even though there were multiple perforations per stage, often only one perforation received the fracture fluid resulting in large sections of the lateral not being stimulated and EURs being adversely affected. Now it is common for a well to have ten or more fracture stages with only one set of perforations over a five feet interval used per stage.

This increases the chances (but does not guarantee) that the slurry will be put in the planned locations. The completion cost for this extra field effort is greater but the increased EURs result in more overall value per well.

Open-Hole Completion

An alternative to using cemented casing is to use an open-hole completion. Open-hole completions are configured in a variety of manners but a simplified description includes an uncemented wellbore with or without casing, liner or screen installed in the open hole section. Each completion method is usually performed for a specific reason depending on formation characteristics and/or the stimulation to be performed. A cemented casing string is the most common completion method utilized for zonal isolation. Common reasons for selecting open-hole completion and not placing cement across the production zone include: 1) prevention of formation damage or skin damage caused by cementing, 2) prevention of fracturing the formation while pumping cement, and 3) prevent filling natural fractures with cement. One relatively new open-hole completion system used in the industry today is an uncemented cased completion using a series of external/open-hole casing packers and ports to accommodate multiple stage acid or frac stimulations. The multi-stage packer and port system provides isolation points in the wellbore where intervals can be segregated and stimulated separately. The packer and port arrangement is spaced out according to the reservoir lithology and treatment plan. The stimulation begins at the toe of the wellbore and stage treatments progress upward along the wellbore. This type of completion has been applied with multi-laterals as well. Once the stimulation treatment is complete, all stages can be flowed back with the diversion balls flowing back to surface. Frac stages are limited to a maximum of nine or 11 stages per lateral depending on casing size.

Sequential Stage Systems for Open Hole Completions

Packers Plus' StackFRAC and Halliburton's Delta Stim Frac are the leaders in the industry with Baker offering a similar system. Weatherford and BJ are rumored to be developing their own systems as well. These multi-stage completion systems have been very effective in horizontal laterals that are commonly completed with multiple stimulation stages. These designs are shown in Appendix 11. The ability to shift ports also provides a major advantage for restimulation consideration providing the ability to manually shift ports opened/closed as desired. Another major advantage of the packer and port systems over the cemented and perforated completion is the time that is saved during the frac procedure resulting in cost savings. The time required to complete a multi-stage frac can be cut into half.

The packer and port completion system has many advantages over the common cemented and perforated completions which are discussed above. The major drawback of the packer and port system is the risk of a system malfunction either by packer failure or ball and seat failure, both could result in stimulation stages not being properly stimulated. This type of failure may not be detectable during the stimulation treatment and would likely result in poor production from the stages that were impacted. Another malfunction causing the inability to open ports would require relying on perforating but could be

overcome. We are aware of these type completions being run in the Barnett shale, the Bakken shale and the Woodford shale with success.

Multi-Stage Fracture Design

The basic goal of hydraulic fracture design is to significantly increase the shale permeability, create as large a drainage area as possible and do this at an acceptable cost, maximizing the real economic return of the well. The basic tools required are wireline logs and their analysis, single stage fracture stimulation modeling and reservoir simulations of the compound effects of multistage fracturing. The first step is wireline log analysis. Appendix 12 is an example of a "shale specific" log analysis for a Barnett shale vertical well in the Fort Worth basin. It has the normal products from log analysis such as gross shale thickness, net shale thickness, average porosity, porosity-feet, and gas saturation. In addition, it also has free gas, sorbed gas and total gas values. These shale properties were derived from a conventional core analysis and calibration with a database of several hundred cores from shale plays throughout the U.S. In this case the free gas is 73.6 scf/ton (standard cubic feet per ton) and the sorbed gas is 26 scf/ton. Total gas is 100 scf/ton. This value equates to total gas-in-place of 58 Bcf per sq mile, which is low. The shale geomechanical properties (Young's Modulus and Poisson's Ratio) are used to model the fracture susceptibility. These parameters are calculated from the compressional (P-wave) sonic log, the shear (Sv and Sh waves) sonic log and the bulk density log. Figure 8 describes these geomechanical properties and their significance.

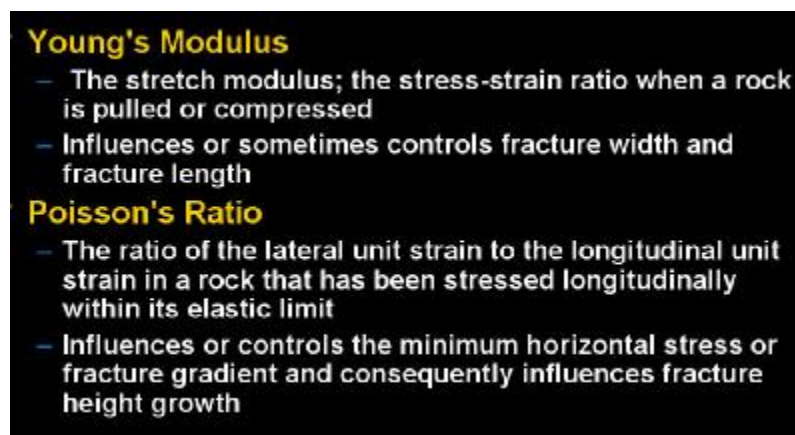


Figure 8: Elastic moduli derived from wireline P-wave, S-wave and density. Used to determine rock elastic response for hydraulic fracture design (Core Lab, 2006).

Modeling and Economic Optimization

The horizontal and vertical growth of hydraulic fractures is estimated from computer simulations of variations of fracture slurry composition and their pumping pressure responses through time. Figure 9 is a fracture half-wing growth model. The vertical changes in geomechanical properties are shown in the depth track on the left with gray being competent shale fracture barriers. The extent of the vertical and horizontal fracture growth is shown to the right.

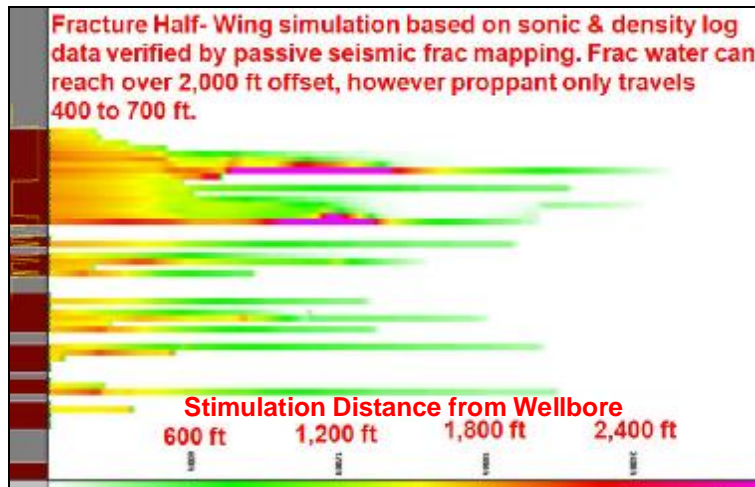


Figure 9: Model of horizontal fracture growth as half-wings (modified from Core Lab, 2006). Color scale is proppant concentration.

The fracture half-wings are calculated from the geomechanical rock properties often using the widely used 2-D FRACPRO software with 3-D approximations. This software is owned by the Gas Research Institute who licenses the source code to third party developers. Some of the variable parameters are vertical and horizontal permeabilities, fracture slurry concentration, pumping rates, perforation spacing and pad volumes which are used to match treating pressure simulations. The model in Figure 9 indicates that some of the fractures could extend out as far as 2,500 feet but that most are within 700 feet of the wellbore. The placement of the lateral within this vertical model is important as the properties vary with depth. These models are often widely optimistic as they do not appropriately correct for the real 3-D anisotropy in the rock parameters. In reality, frac mapping has shown that the slick water can move out as much as 3,500 feet from the wellbore. This type of simulation cannot yet effectively map the extent of the proppant movement. Many engineers estimate that actual proppant placement is no more than 700 feet from the wellbore and often much less than that value.

Once optimum fracture designs have been determined, the results are used in a reservoir simulator to optimize from single to multi-stage fracture design by evaluating the interaction of the fracture propagation in 2-D and 3-D space and its effects on rock permeabilities and fluid flow. Figure 10 is the result of such modeling to determine the optimal horizontal fracture length, spacing of each set of perforations and the number of fracture stages. The graph shows cumulative gas recovery in Bcf versus production time out to 33 years. Results of several simulations are plotted indicating that the best outcome is a 3,000 ft lateral with 15 stages set 400 feet apart with isotropic permeability ($X_{\text{horizontal}} = Y_{\text{horizontal}}$). This scenario recovers almost 5 Bcf over the project life. The next best result recovers 4.5 Bcf with the only difference being that the permeability parallel to the fracture direction is assumed to be 10 times greater than the permeability normal to the fracture direction. Variations on these assumptions and results will become important in determining optimum well spacing later.

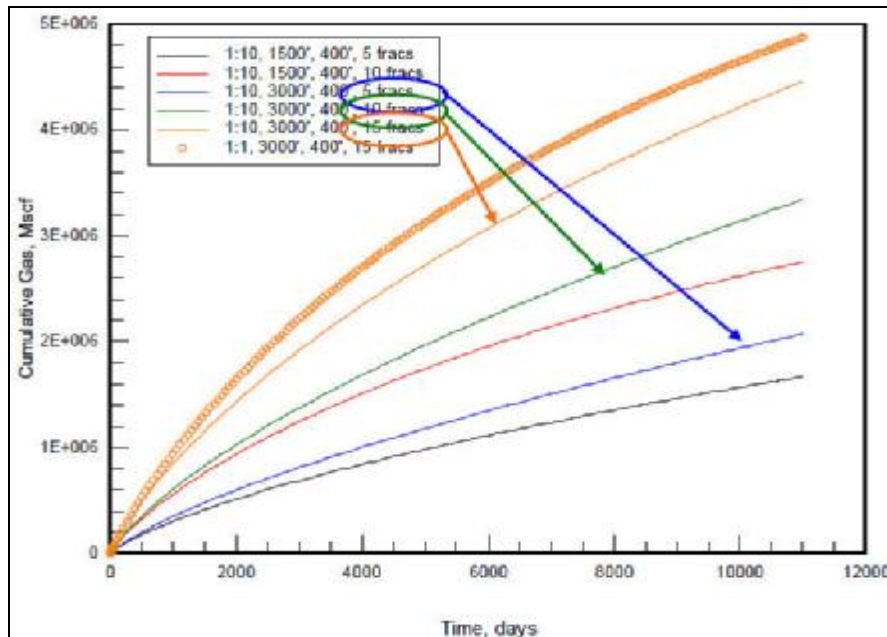


Figure 10: Improving shale permeability and EUR by multiple frac stages (Downey, 2008).

The economic significance of the optimum hydraulic fracture design is shown in Figure 11. This graph also shows cumulative gas production versus project life, in this case only to 3.3 years. In this case the parameter modeled was the recovery improvement and additional cash flow to the well as the length of the fracture half-wings was increased. The model indicates a US\$10.5 million improvement in cash by increasing the proppant filled fracture half-wing from 100 feet to 1,200 feet.

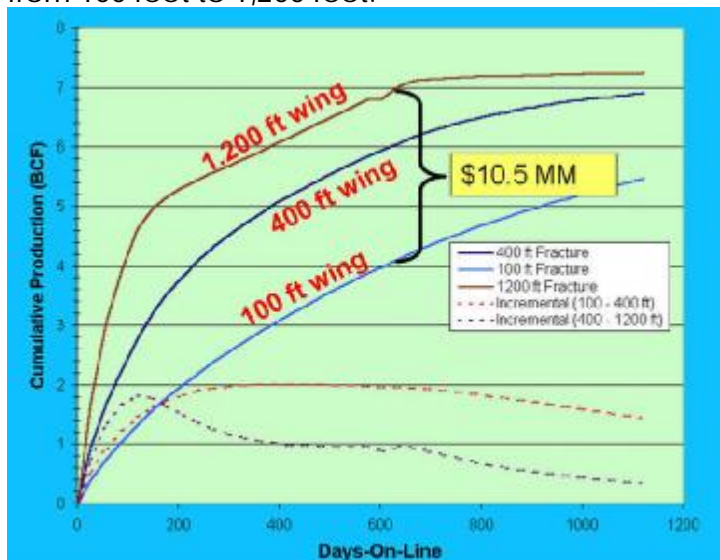


Figure 11: Production forecast of economic advantage of longer fracture half-wings (Core Lab, 2006).

This estimate probably minimizes the effect of the smaller wing distance and maximizes the largest wing distance. The reality is most likely somewhere in-between. However, increasing well density and fracture density can make the 100 foot to 200 foot fracture spacing (both transverse and longitudinal) possible and significantly increase recovery factors. This exercise does illustrate the general poor nature of this type of model driven analysis in the early stage of a shale gas project. The results are more realistic when a large well production database of 100s of wells is available. It is then possible to use conditional simulation and other arealy based statistical analysis tools (known as geostatistics) to assist in predicting fracture performance probabilities and influence on EURs.

Application in North America

Even with the best simulation work for well azimuth and fracture design there can still a large degree of uncertainty in results. This is best illustrated in Appendix 13. This is a comparison of a frac map in the Barnett shale in North Texas with a frac map of a Woodford Shale well in Southeast Oklahoma. The Barnett well to the left shows a fracture transverse to the well azimuth that trends northwest to southeast. The MxHS appears to run southwest to northeast. The cross-section of the frac map below shows that both fracture stages are contained within the objective. In contrast the Woodford shale well on the right exhibits a much disorganized pattern in the map view and it is not possible to easily discern the MxHS direction. The cross-section below also shows a disorganized pattern with a large amount of structural dip over the 3,000 feet between the observation and treated wells evidencing possible structural complexity. Production in the Woodford well is most likely poor.

Moving from the computer modeling phase to another real example, we can look at a graph of flow back volumes and pressures for a typical Barnett Shale well after a five stage 80,000 bbl hydraulic fracture. Usually the practice is that after the last fracture stage is completed the pumping equipment and specialized wellhead equipment is removed, the well choke immediately opened for flow back to the atmosphere, and the plugs removed during the beginning of flow back. Appendix 14 is a typical well flow back graph. The upper graph shows water rate in bbl per hr and mcf gas per bbl of water. It also shows the choke size in 64th inch. The graph on the bottom shows gas rate in Mmcfgpd and flowing casing pressure in psia. Both graphs are plotted against time when the well was opened for flow back. The total time period shown is 23 days. A coiled tubing rig was moved in to drill out the plugs and the well was intermittently flowed during this period. Flow back began in earnest on the third day at over 100 bbl per hr. The casing pressure immediately began to rise on the fourth day. On the fifth day (the second day of open choke) the casing pressure topped over 1,500 psi and gas production began. The choke size was constrained keeping the water flow between 30 to 50 bbl per hr and gas rate to 6 Mmcfgpd to limit the amount of proppant flowing up the wellbore. On the 15th day the choke was full open with gas production over 10 Mmcfgpd and flowing casing pressure (fcp) over 800 psi. At the end of the 24th day the gas rate was 7.5 Mmcfgpd and 750 psi fcp. At that time it had produced 25,000 bbl of frac fluid and very little sand. The well produced frac water for several additional months recovering less than 40% of the total volume of fracture fluid. Shale gas

wells rarely produce back more than 1/3 of the total fracture fluid. Wells that produce over 50% often are poor performers.

Maximizing Recovery Factors and EURs by Well Spacing and Simultaneous Fracturing

Hydraulic fracturing is designed to increase the permeability of the gas shale by creating a fracture network that, in the best case, expands normal from the horizontal lateral. It is also desired that another fracture network normal to this transverse network be created, in effect creating a fracture grid of permeability channels. Possible fracture networks (in this case from a vertical well) are shown in Figure 12. The optimum fracture network is in the lower right hand corner. This illustration also applies to horizontal wells. It illustrates that more fractures parallel to the MxHS and smaller conjugate orthogonal to MxHS fractures are most desirable.

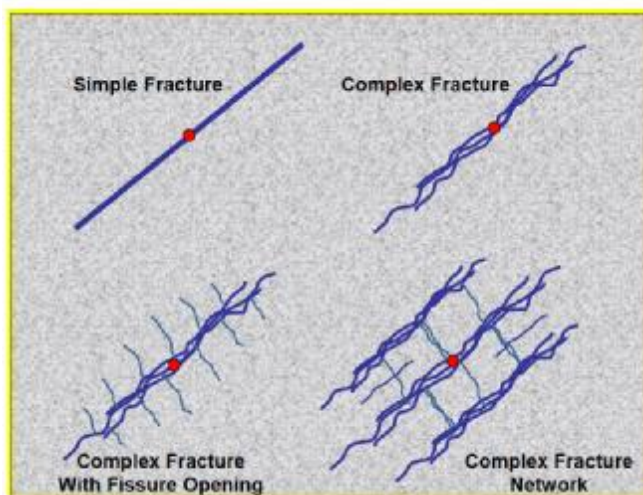


Figure 12: Desired induced fracture complexity is in the lower right hand corner (Mayerhofer, 2008a).

As thousands of horizontal wells were drilled in the Barnett Shale and many had the benefit of frac mapping, it was noticed early that as the distance between the horizontal wells and the spacing of fracture stages were decreased, there appeared to be changes in the direction of fracture propagation that were not related to the MxHS direction. It appeared as if the MxHS was rotating such that fracture propagation would initiate in one direction and then after the fracture had moved a distance from the horizontal lateral, the fracture direction would then trend toward the expected direction. Literature investigations showed that this was an indication of stress anisotropy or also known as “Stress Shadow Fracturing”, a phenomenon well known in structural geology and rock mechanics. A medium is anisotropic if its properties vary with direction. This is the general characteristic of many rocks; for example, schists, slates, gneisses, phyllites and other metamorphic rocks. Bedded and regularly jointed rocks also display anisotropic behavior (Amadi and Goodman, 1982). This applies to the stress fields as well. Rocks under high stress with well developed MxHS will exhibit very narrow focused fracture patterns. Lower stressed rocks will exhibit more

disorganized fracture patterns. Stress Shadow Fracturing is the process where early fracturing in a horizontal wellbore rotates the focused MxHS direction with later stage induced fractures following the new MxHS and then eventually trending back to the expected direction with offset. This concept is shown in Appendix 15 which is a top and side view of a horizontal well. The author tries to show longitudinal fractures developing within the induced fractures on both sides.

Simo-Fracturing Concept and Technique

The implication of this occurrence is important to shale gas recovery factors and EURs. It means that if horizontal wells are drilled at very close spacing and simultaneously fractured with very short stage separation, without flow back until all wells have completed fracturing, that a very closely spaced set of fractures in both transverse AND longitudinal directions can develop, tying all the wells together through permeability pathways. This would create large avenues of permeability in both horizontal directions that are all connected to the well perforations. Apparently the magnitude of these pathways overcomes any near wellbore tortuosity that may develop. Appendix 16 also attempts to show how this technique, also called "simo-fracturing" could actually be achieved. In this example, five wells are drilled parallel at 500 foot spacing. Inter-fingering frac stages are used such that no well has more than seven frac stages as the well spacing allows fracture expansion across adjacent wells. This minimizes completion costs. Each frac stage is run sequentially within a well and simultaneously across all wells. The wells are not flowed back until all fracturing is completed. Delay of flow back allows pressure build up within the interior wells and leads to lower stress anisotropy allowing rotation of the MxHS. The frac map of a single well exhibiting stress anisotropy is shown in Figure 13. Here a well with a four stage frac is shown. The Stage 1 and Stage 2 fracture pattern appears normal to the wellbore, following a transverse MxHS and is in a high stress and anisotropy area with a narrow fracture fairway. However Stages 3 and 4 are less well defined as if these patterns are a mixture of transverse and longitudinal fracturing and are in a lower stress zone with a much wider fracture fairway. The conclusion based on this well and similar response of other wells is that the first two stages rotated the MxHS affecting the last two stages.

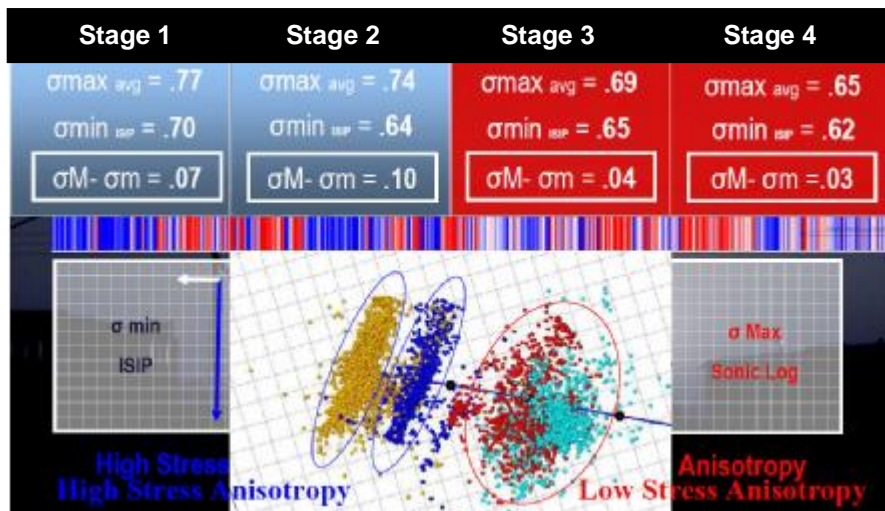


Figure 13: Actual stress anisotropy example. Stages 1 & 2 (left) produce transverse fracture (high anisotropy). Stages 3 & 4 have new rotated MxHS stress (low anisotropy) non transverse as a result of Stages 1 & 2 (Downey, 2007).

The positive effect on gas production of stress shadow fracturing is demonstrated in Figure 14. It shows a decline curve comparison of two sets of closely spaced horizontal wells, nearby on the same lease but far enough apart so there is no interaction between the sets of wells. The green curve is the production of two closely spaced wells that were fractured normally; the flow back began after completion of the last fracture stage in each well with a possible elapsed time delay as well. The blue curve represents two wells drilled at the same horizontal spacing as the green; however, the blues were fractured simultaneously with flow back beginning only AFTER the hydraulic fracturing of both wells was completed. The blue curve combined rate starts higher than green and continues higher out to 23 months when the data end. The author implies that similar responses are shown in similar comparisons.

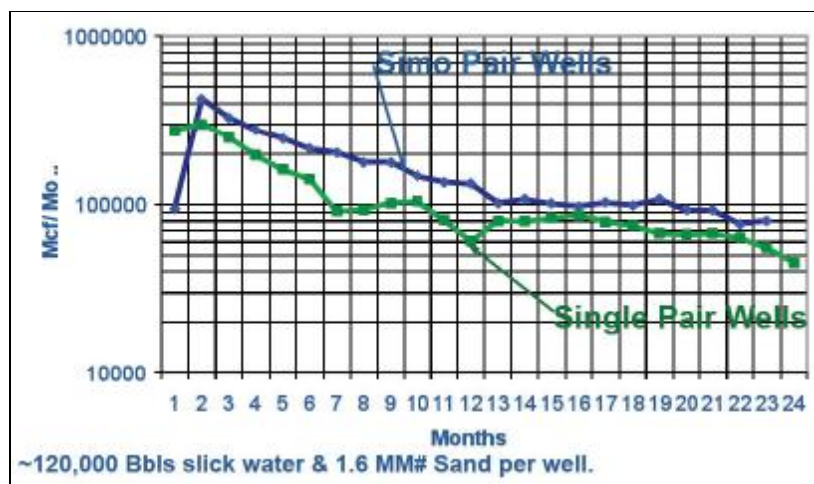


Figure 14: Comparison of production from two simo-fractured wells and two wells same spacing but not simo-fractured. This is an example of production improvement due to Stress Shadow fracturing (Schein, 2009).

Applications in North America

A significant large scale example of this technique was published by EOG in 2008. This is shown in Figure 15. In this case EOG drilled five horizontal wells from three surface locations on a 192 acre lease in the Barnett shale play in Johnson County in early 2007.

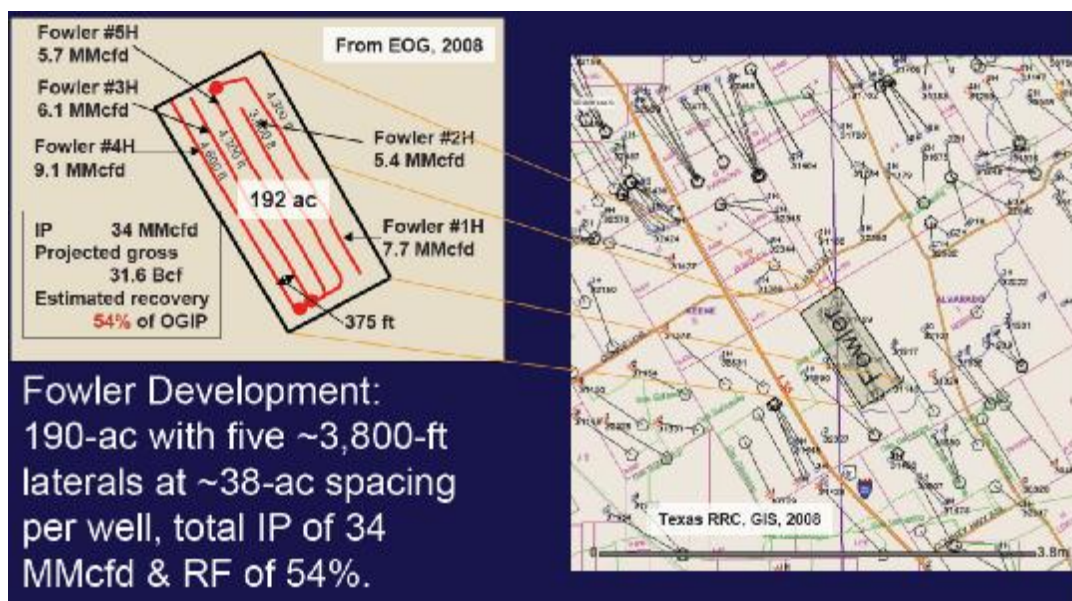


Figure 15: Application of "stress-shadow" fracturing in Barnett shale, Johnson County (Wang, 2008).

The well azimuths are transverse to the MxHS in this area. The wells had 3,800 ft laterals and were spaced 375 feet apart. This spacing and the nominal 34 acre drainage area ensured that there would be communication between wells during fracturing. The spacing was also within the horizontal range of proppant delivery (within 700 feet). All wells had 5 1/2" casing run from TD to the surface. All five wells were simultaneously completed using the stress shadow fracturing technique and flowback did not begin until all fracturing of all wells had been completed. As shown, the initial rates of the five wells ranged from 5.4 to 9.1 Mmcfgpd with a combined initial flow rate of 34 Mmcfgpd. The gas-in-place for this area was determined by other data to be 195 Bcf per square mile. EOG claimed that they would recover 31.6 Bcf gas which is 54% of the gas-in-place. If this is true, the recovery would triple the best "average" recoveries of about 15% of gas-in-place in the whole Barnett shale play. EOG holds all the leases in this area. It can be seen from the base map on the right side of the figure that they appear to have several other stress shadow fracture production projects in operation. To further investigate this claim we prepared decline curves for the five wells. All wells had 17 months of production. The results are shown in Appendix 17. The EURs for the five wells ranged from 3.49 Bcf up to 5.38 Bcf. Assuming that no refracturing of the horizontal wells is anticipated as no provision was made by using open-hole sleeve packer completion, the combined EUR of the five wells is 21 Bcf. This leads to a recovery factor of gas-in-place of 36%

which is still twice the 15% for the Barnett Shale play as a whole but 1/3 less than the EOG value. EOG may envision other recompletion techniques to increase the gas recovery factor. However, if EOG had used open-hole sleeve packer technology instead of cemented casing, these horizontal wells could be refractured, in effect again resetting the MxHS and opening additional permeability paths within the shale, possibly further increasing the recovery factor toward the 54% as they now claim.

There are other examples of stress shadow fracturing. Appendix 18 shows another Barnett Shale development area in south Tarrant County. Range Resources will drill 26 wells on 2,200 acres with well spacing varying from 250 feet to 500 feet. Nominal drainage area is 85 acres, almost 2 ½ times that of the EOG project. Notice that the well azimuths vary substantially, seemingly without regard to MxHS. This may be due to the lease dimensions constraining surface locations and lateral paths or it could be due to the anticipated success of stress shadow fracturing. The recovery factor and individual well EUR are such that these wells will be very economic. Other gas shale operators have similar projects in progress in the Barnett Shale and the other gas shale plays. If this development trend accelerates then the total gas recoveries from the Barnett and other shale gas plays could increase significantly.

Economic Significance of Recovery Factors and EURs

Large amounts of gas-in-place and high recovery factors are the main drivers for technical success in gas shale plays. These factors can be closely linked to successful well completions. However individual well costs and their economic outcomes are also factors to consider in evaluating total shale gas project success. Economic outcomes for a gas shale play can vary arealy due to several costs such as drilling depth, drilling complexity, completion costs, surface accessibility, and low gas recovery factors, to name a few. Once large databases have been established, it is possible to map these factors to assist in focusing on those areas that have the highest overall economic outcome. One way to do this is to determine the internal rate of return which is an economic indicator that encompasses all investments, cash flows, and operating costs (the supply costs) and well productivity to determine project worth. A map of a five county area of the Barnett shale in the Fort Worth basin is shown in Figure 16. This shows the economic indicator on the left and the supply cost on the right. Wells in areas of red color on the map on the left have the highest economic worth. On the right map, wells in areas that are red have the lowest supply cost. Generally, in this case, the high economic worth coincides with the low supply cost. This may not always be true however. Depending on the supply cost and the well EURs it is possible that even the highest supply cost wells could have the better economic indicators. The success of the well completions will have a primary role in determining outcomes of these types of economic assessments.

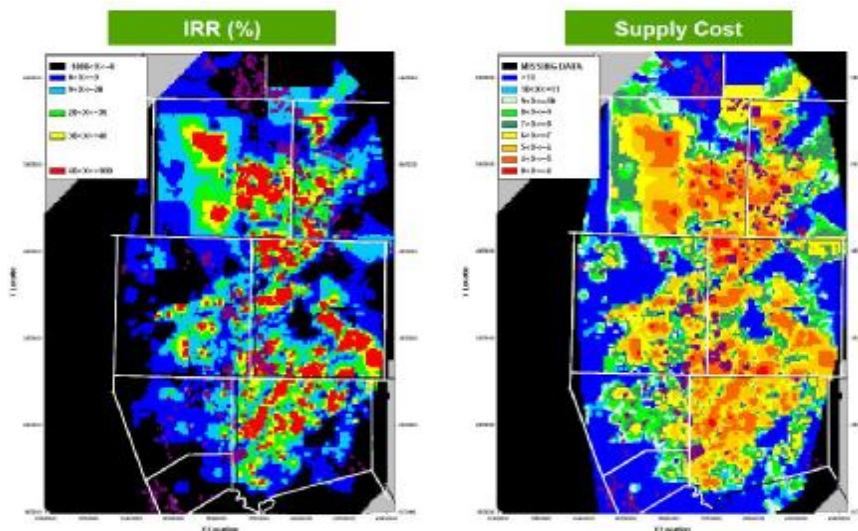


Figure 16: Gas Shale Development Outcomes - Economic indicator versus supply cost, Barnett shale, Fort Worth Basin (Sander, 2009).

Shale Gas Development and Trustworthy Land Use

During the 10 years that the development of shale gas slowly began and then has grown exponentially, the production operators have shown that they can be good stewards of the land. The footprint of drill sites and fracture water pits has continued to shrink until just the minimum amount of land is necessary for drilling, generally five acres. It is then reduced down to two acres once hydraulic fracturing is completed and production facilities are installed. This work often takes place nearby or even within residential environments as Appendix 19 illustrates. In extreme cases even smaller drill pads can be used as shown in the fracture completion activity in Appendix 20. The result is that the surface land owners usually can accept the temporary inconvenience of the drilling and completion periods. Gathering systems are designed to have minimum impact on road systems. Drilling and completion technology development has greatly assisted in making shale gas development more cost and resource efficient. The large assembly of hydraulic fracturing equipment such as that used in the Barnett Shale play in Denton County in early 2004 and shown in Appendix 21 is no longer needed. Instead smaller, more efficient pumping equipment and techniques as shown in Appendix 22 can now provide the equivalent down-hole impact to maximize the well EURs and move the gas recovery factors even higher.

Conclusions

Technology and operational techniques have been developed over the last ten years by many gas exploitation companies to efficiently and optimally develop shale gas reservoirs. Significant investments have relatively quickly ramped shale gas production to over 5 Bcf today in the U.S. by continued application of known engineering practices and extending them into the unknown. The integration of many technologies and sciences has been required to make shale gas exploitation a success. Recovery factors have increased by novel exploitation of existing knowledge. Continued improvement is possible as

new understanding of the interactions of subsurface stress fields and their effects on hydraulic fracturing are uncovered and exploited. The possibility of re-fracturing horizontal wells can further increase recovery factors. These technology applications can be effectively transferred to other areas in the world that have the correct mix of geological attributes, infrastructure and land access.

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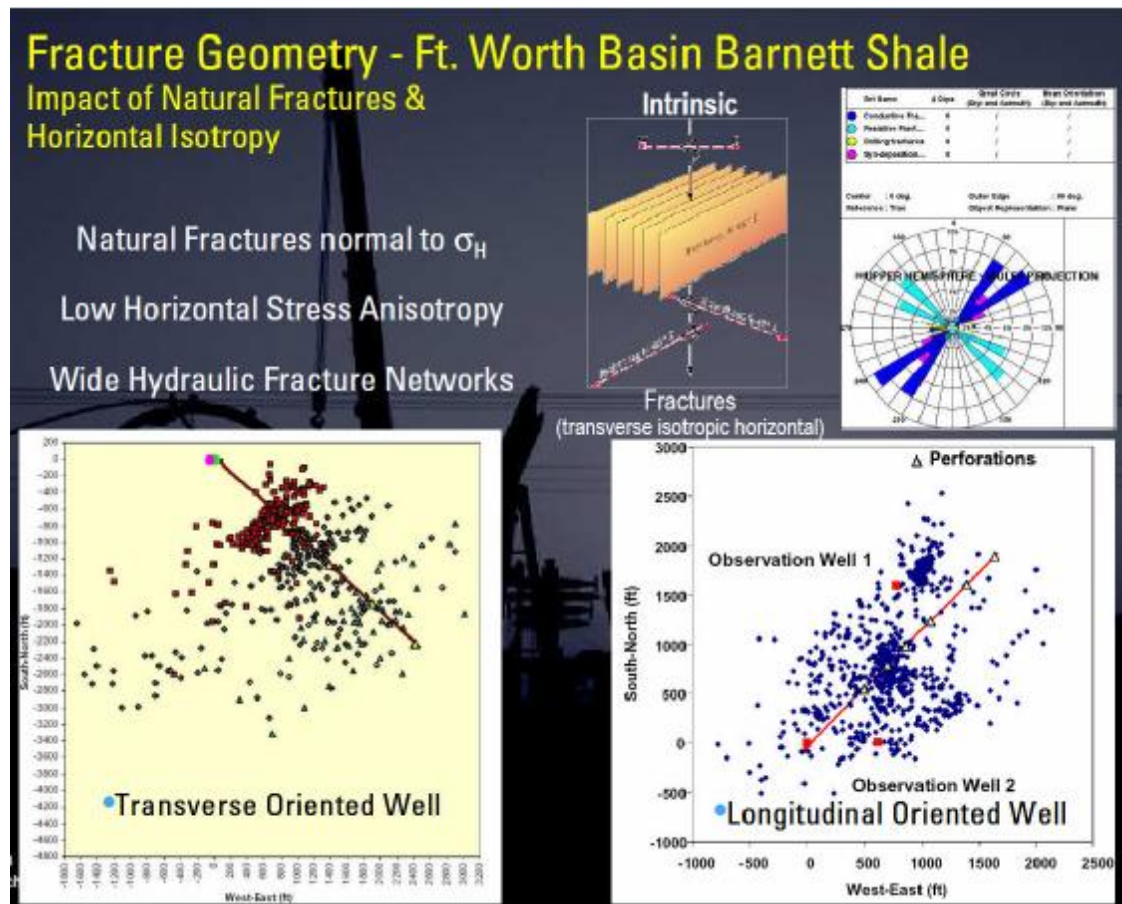
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About the Principal Author

A native of Kermit, Texas, Stephen Smith (Steve) came to Harding Company in 2005 as Vice President of Operations, bringing with him more than 30 years of experience in the oil and gas industry in seven states as well as in the countries of Mexico, Algeria and Tunisia, North Africa. His areas of expertise include all drilling technologies, High Pressure, High Temperatures (HPHT), Heavy mud weights with Oil Base Mud systems, under-balanced and mud-cap drilling, multi-lateral drilling and completions, workovers, re-completions, well logging and interpretation with reservoir simulation and fracture designs as well as multiple computer applications. He has managed the successful drilling and completion operations of wells with depths down to 30,000 feet both onshore and offshore. He is the third generation of his family to have been employed by Sid Richardson & the Bass Family, where he spent 8+ years working as an Assistant Drilling Engineer in its West Texas Division Office in Midland. Smith's professional membership includes the Fort Worth Petroleum Club, Fort Worth Society of Petroleum Engineers, Petroleum Engineers Club and American Association for Drilling Engineers. He is

also very active in his Church, Boy Scouts of America and coaching multiple sporting events with his son. Current President of STEKAT Resources, LTD & SDS Joint Ventures, he has held other key post with other companies, such as Anadarko Petroleum Corporation, First Calgary Petroleum, Aspect Oil & Gas and Clayton Williams. His training has included technical and professional courses at various colleges and universities in the U.S. and Europe.

Appendix 1



Fracture mapping of actual wells showing relationship of M_{xHS} and induced fracture orientation (Downey, 2008).

Appendix 2



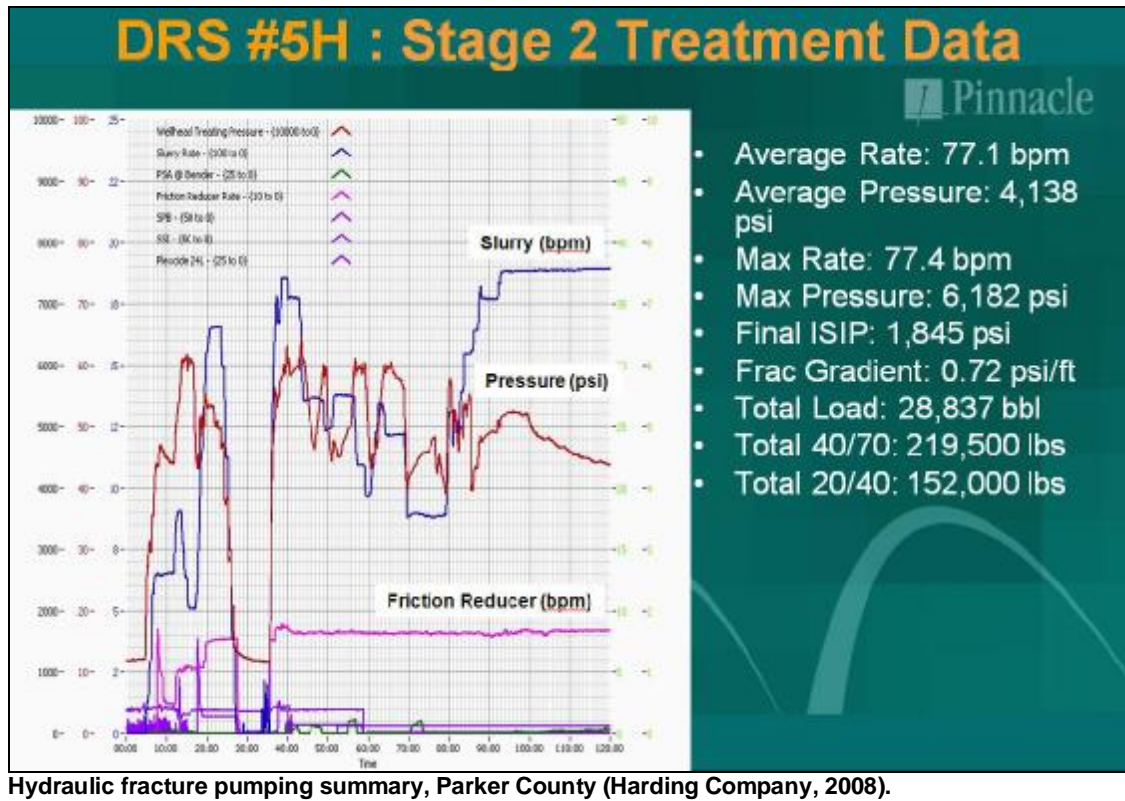
Photos of exposed fractures from Colorado and Oklahoma (Burnaman & Ward, 2003).

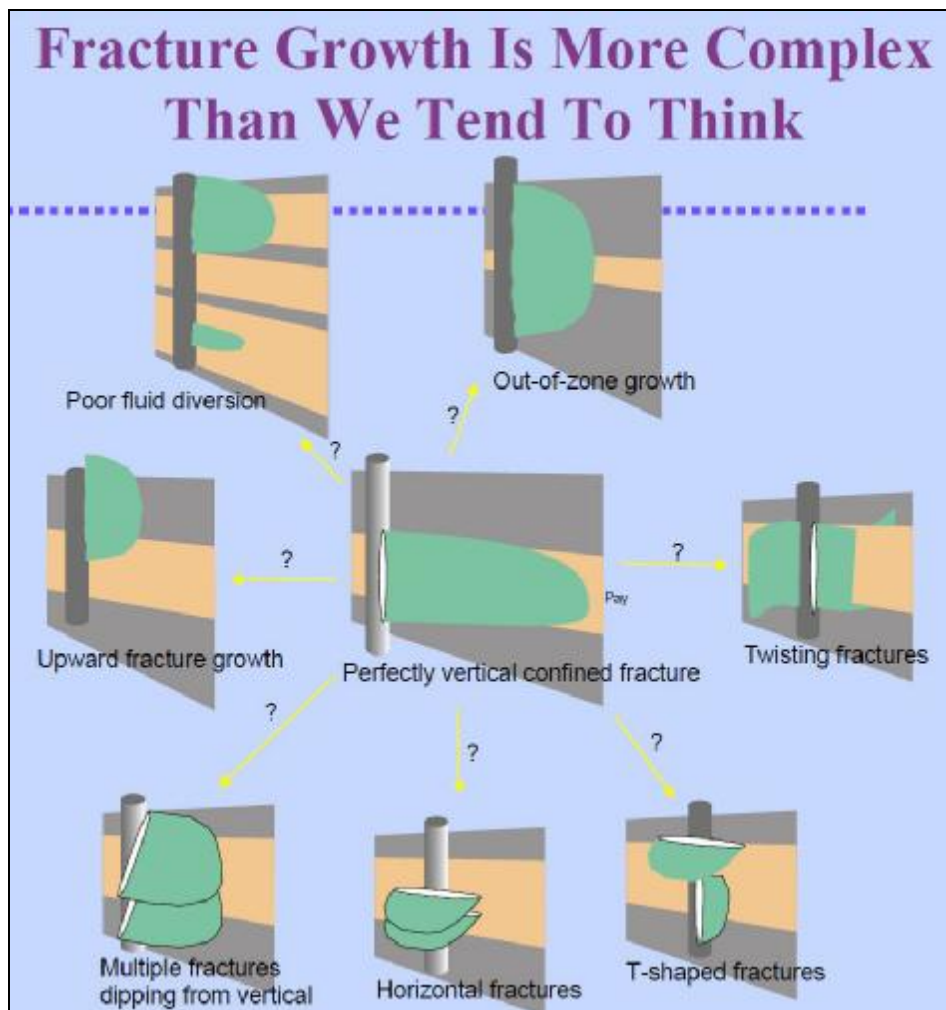
Appendix 3



Same as Appendix 2 but with fracture patterns highlighted (Burnaman & Ward, 2003).

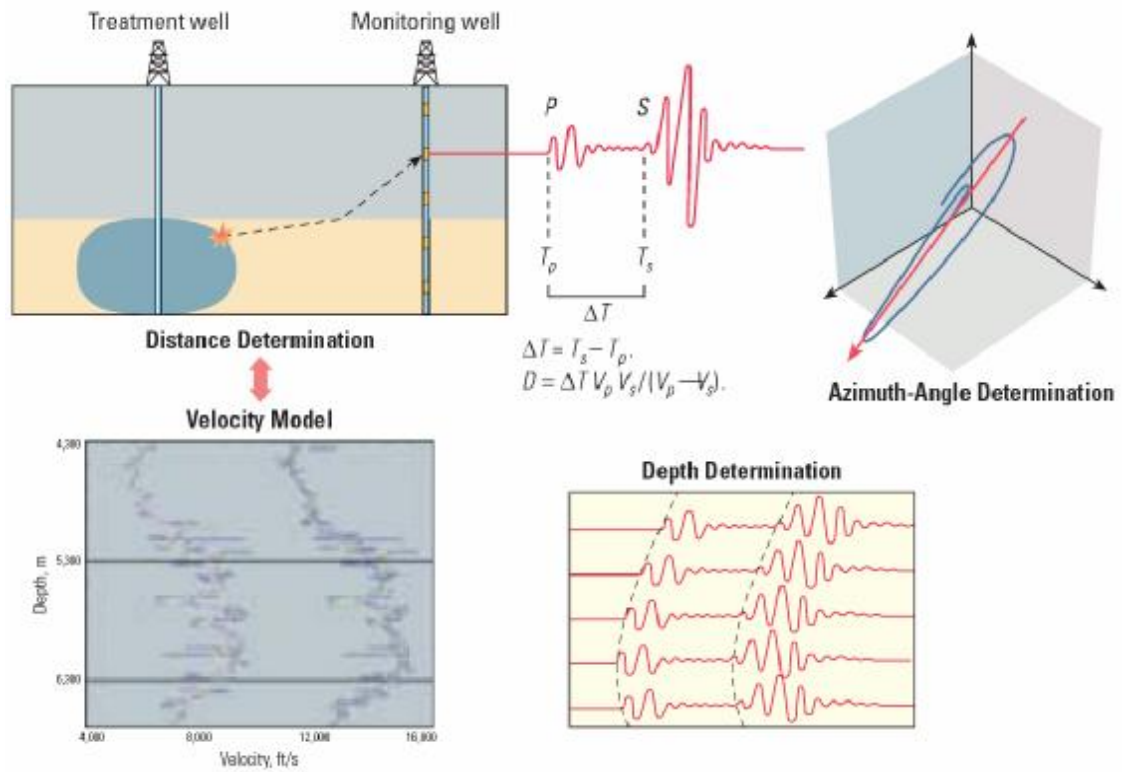
Appendix 4





Various scenarios of complex horizontal fracture growth (Wohlhart, 2001).

Appendix 6



Components of fracture mapping (Bennet et al, 2005/2006).

Microseismic Monitoring Value

Improving return on stimulation investment

Coverage

- Zonal: is the pay zone targeted covered?
- Lateral: is the opened zone properly stimulated?

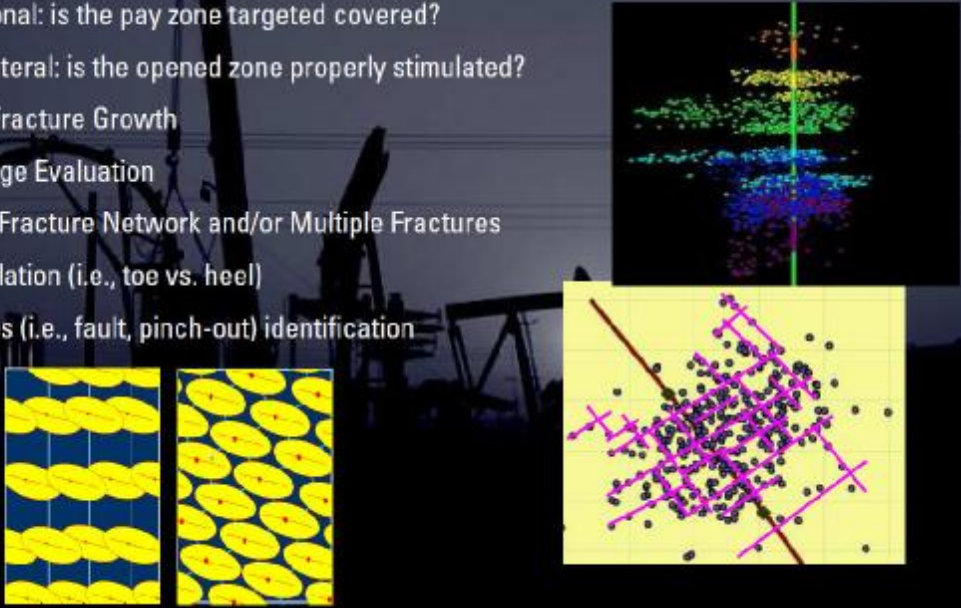
Vertical Fracture Growth

Multi-Stage Evaluation

Complex Fracture Network and/or Multiple Fractures

Zonal Isolation (i.e., toe vs. heel)

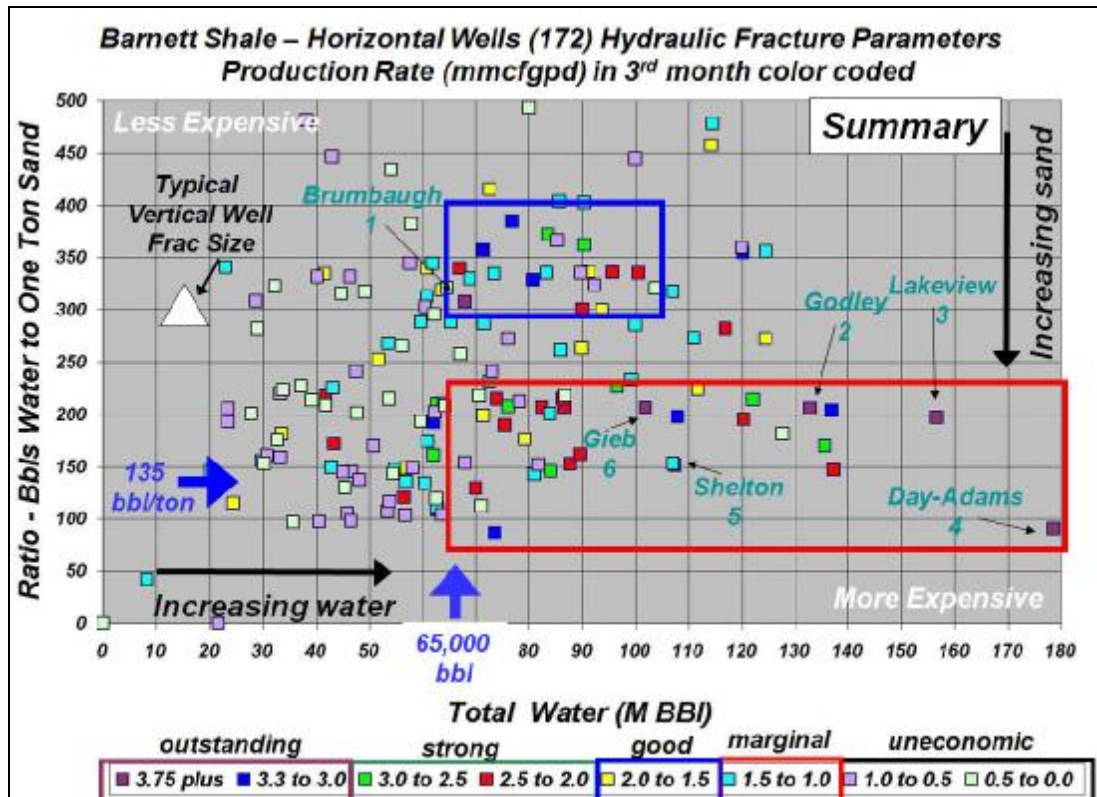
Structures (i.e., fault, pinch-out) identification



The image contains three distinct visualizations related to microseismic monitoring. The top right visualization is a 3D scatter plot showing a complex network of fractures in various colors (yellow, green, blue, red) against a black background. The bottom left consists of two side-by-side cross-sectional views of a wellbore, showing multiple yellow elliptical fracture stages along its length. The bottom right is a 2D map view showing a dense network of purple and pink fracture lines on a yellow grid, with black dots indicating specific microseismic events.

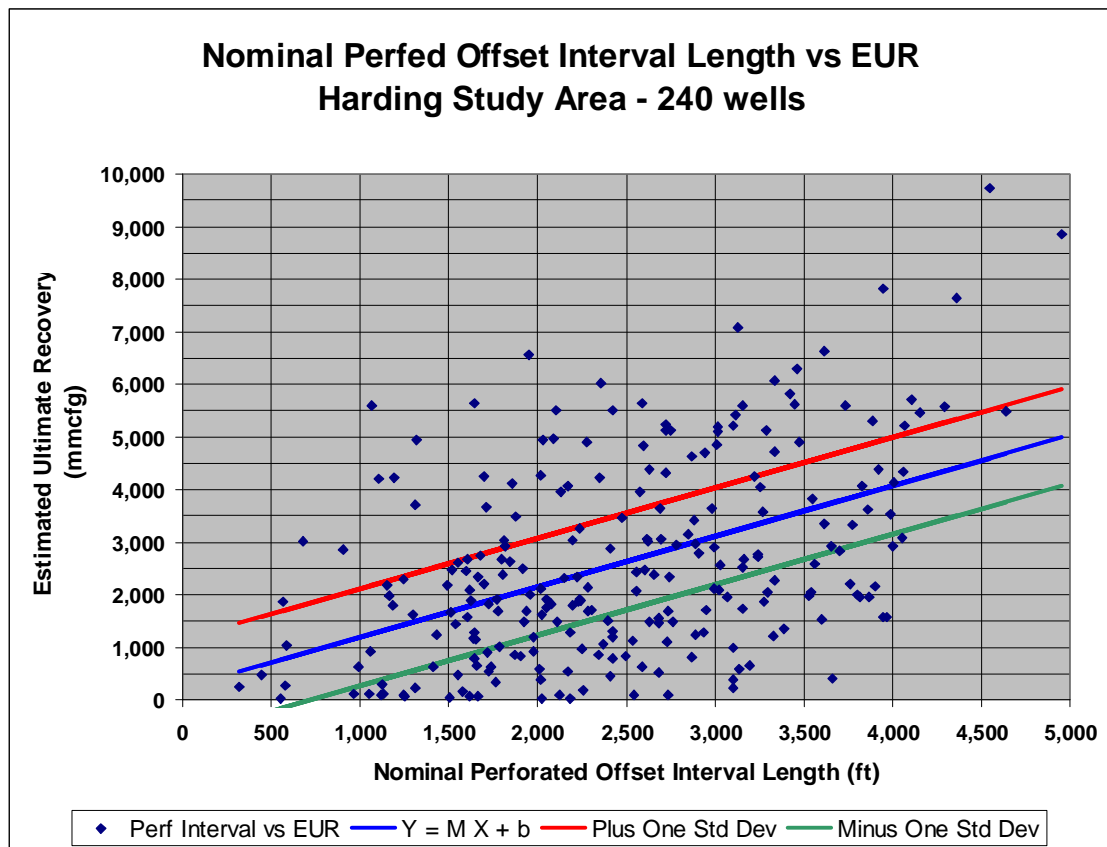
Value of fracture mapping (Downey, 2008).

Appendix 8



Fracture fluid and proppant volumes versus well productivity (Burnaman, 2005).

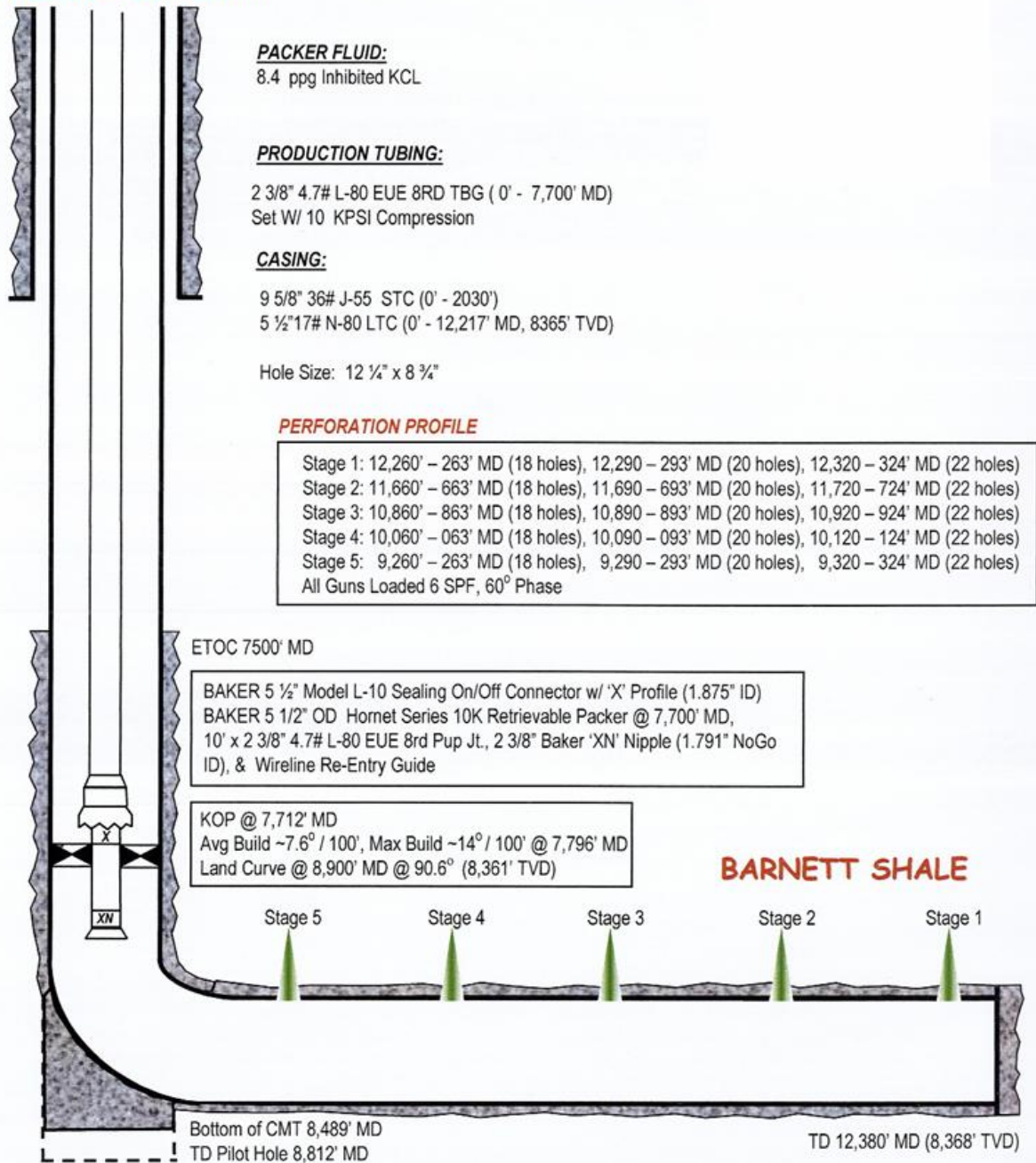
Appendix 9



Comparison of perforated offset interval versus EUR for horizontal shale gas wells (Anon., 2007).

Appendix 10

PROPOSED COMPLETION



Wellbore schematic of Barnett shale lateral showing cemented casing design and perforation plan (Harding Company, 2006).

Appendix 11

The diagram illustrates two different well completion approaches for horizontal open hole shale gas completions. The top section, labeled 'Halliburton', shows a wellbore with a liner and sleeve ports. It includes a 'Challenge' (cost-effective design for multiple stage stimulation), a 'Solution' (Delta Stim completion service, Delta Stim sleeves, and Swellpacket™ Lite systems), and a 'Result' (pumped 5 stages in 9 hrs 54 minutes compared to 2 days for conventional method, 27% completion cost savings). The bottom section, labeled 'Packers Plus', shows a wellbore with a liner and sleeve ports, controlled by multi-diameter balls. The text below the diagrams states: 'Two Approaches to Horizontal Open Hole Shale Gas Completions Use of 4 1/2" & 5 1/2" Liners with Sleeve Ports separated by Packers Controlling Packers & Ports is Initiated by Multi-Diameter Balls'.

Challenge:

- Provide a cost effective openhole completion design that allows for multiple stage stimulation treatments in a single day

Solution:

- Delta Stim completion service
- Delta Stim sleeves and Swellpacket™ Lite systems

Result:

- Pumped 5 stages in 9 hrs 54 minutes compared to 2 days for conventional method
- 27% completion cost savings to customer

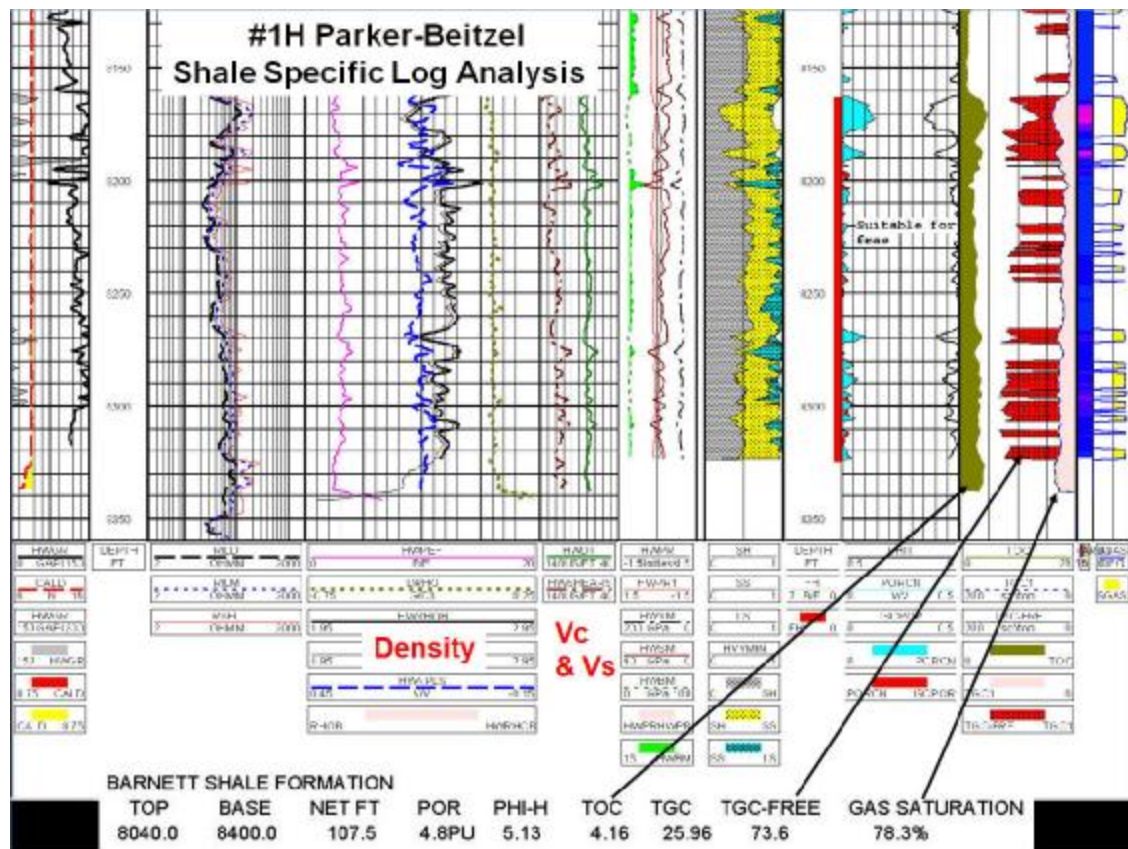
Halliburton

Packers Plus

Two Approaches to Horizontal Open Hole Shale Gas Completions
Use of 4 1/2" & 5 1/2" Liners with Sleeve Ports separated by Packers
Controlling Packers & Ports is Initiated by Multi-Diameter Balls

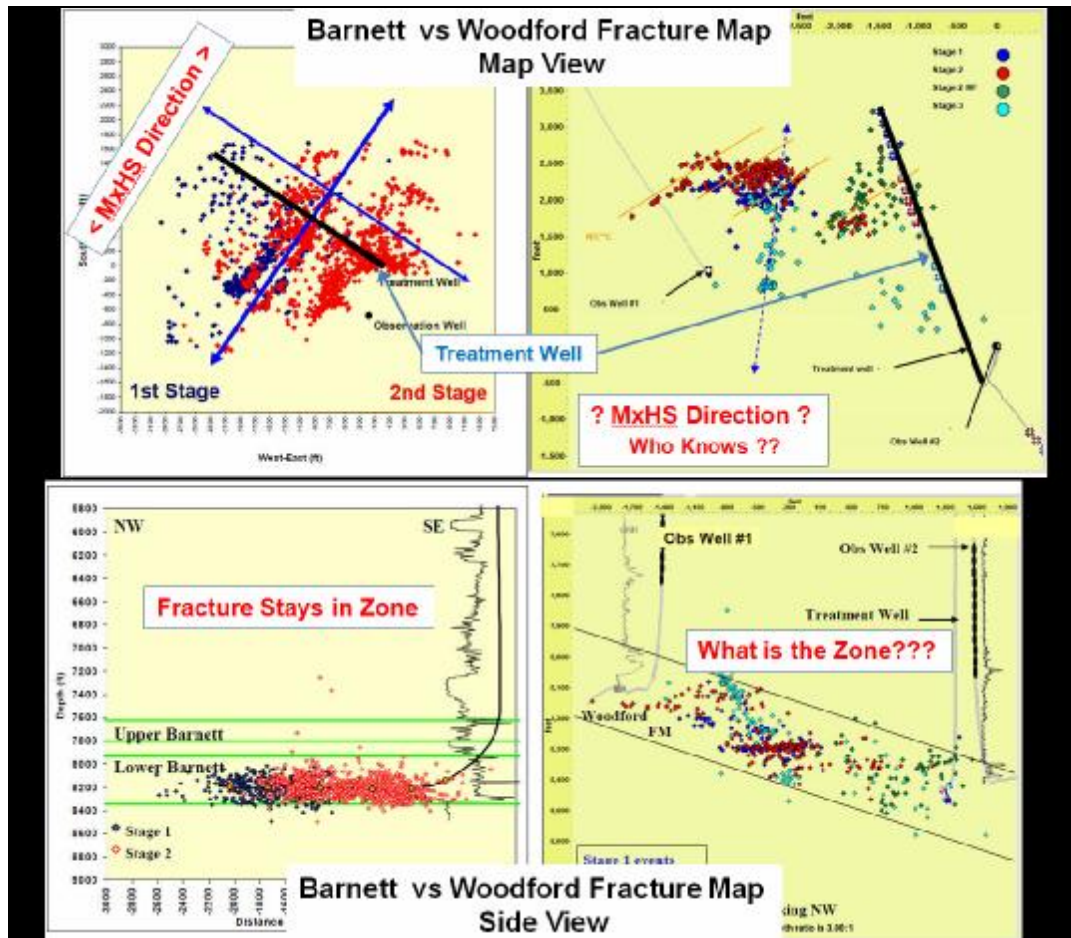
Two open-hole (cementless) wellbore completion designs both using liners and sleeve ports (Halliburton, 2008 & Themig, 2009).

Appendix 12



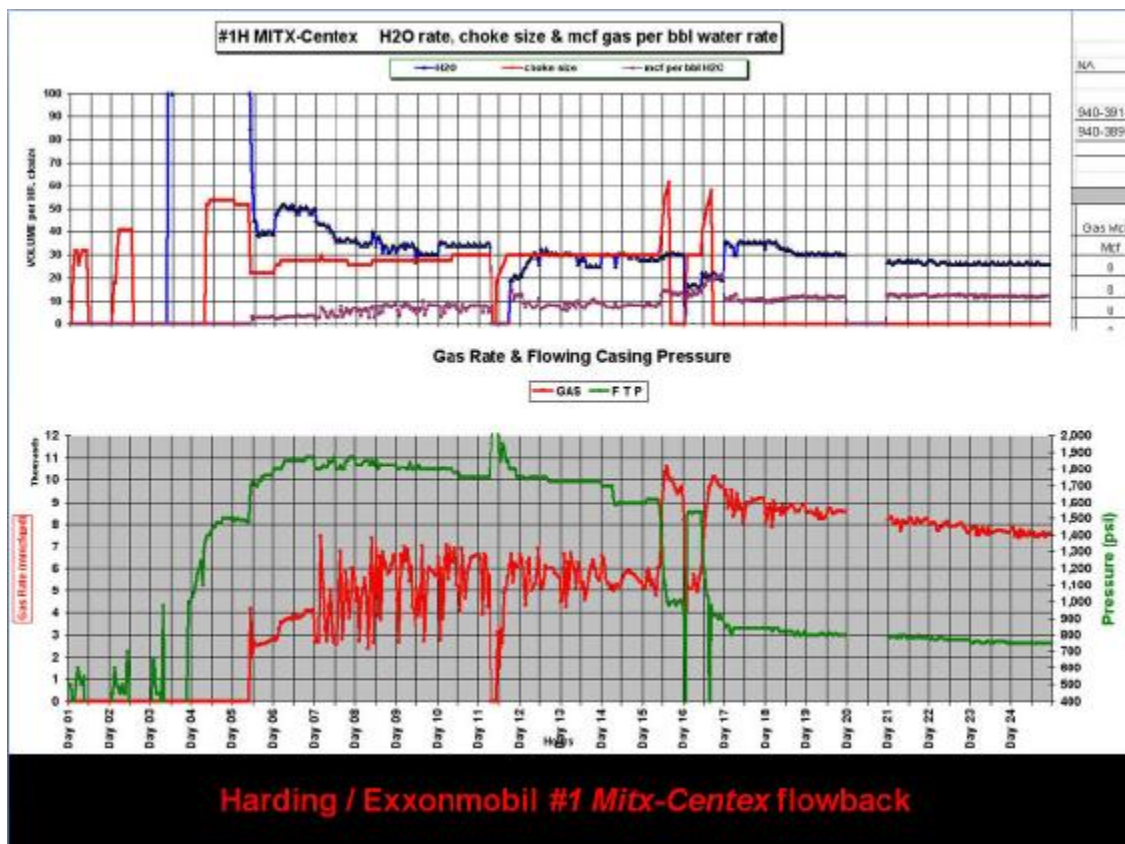
Wireline reservoir evaluation, Barnett shale, Tarrant County, used for vertical placement of lateral and reservoir property parameters (Harding, 2006).

Appendix 13

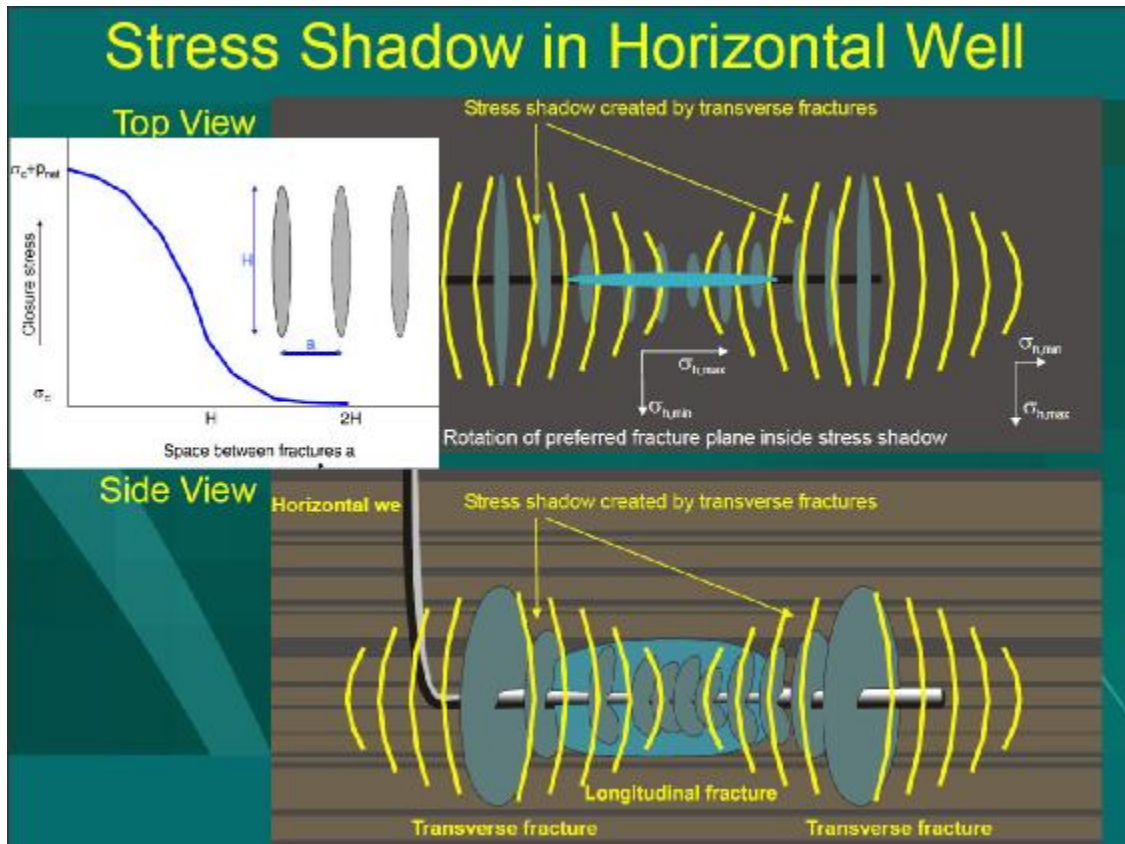


Comparison of optimum design Barnett shale fracture stimulation (left) versus a non-optimum design Woodford shale fracture stimulation (right). Not all design parameters, especially MxHS direction were understood for Woodford Shale (modified from Mayerhofer et al, 2008).

Appendix 14



Well flowback rates, Barnett shale, Tarrant County (Harding-ExxonMobil, 2007).



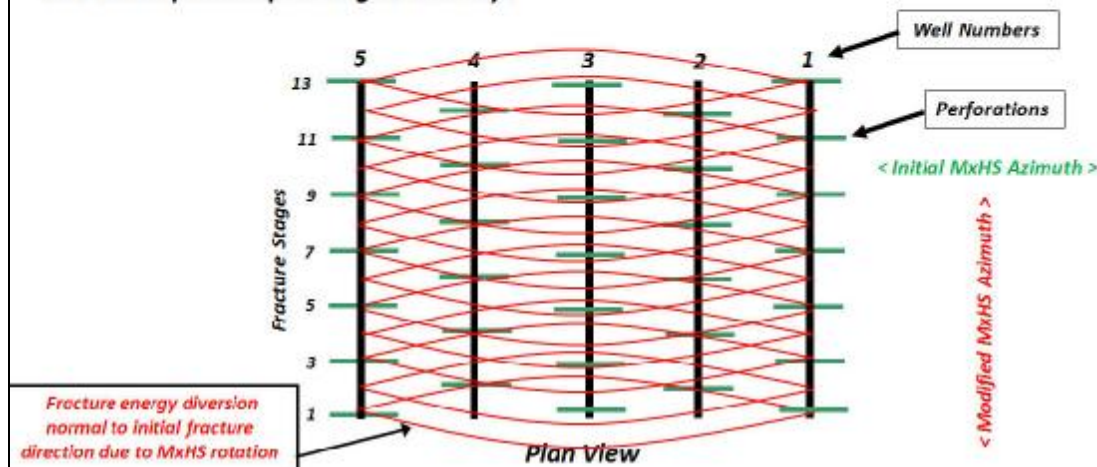
Stress shadow fracture theory of rotation of MxHS (Wright, 2007).

Stress Shadow Fracturing (Stress Anisotropy)

"Hammer & Anvil Approach"

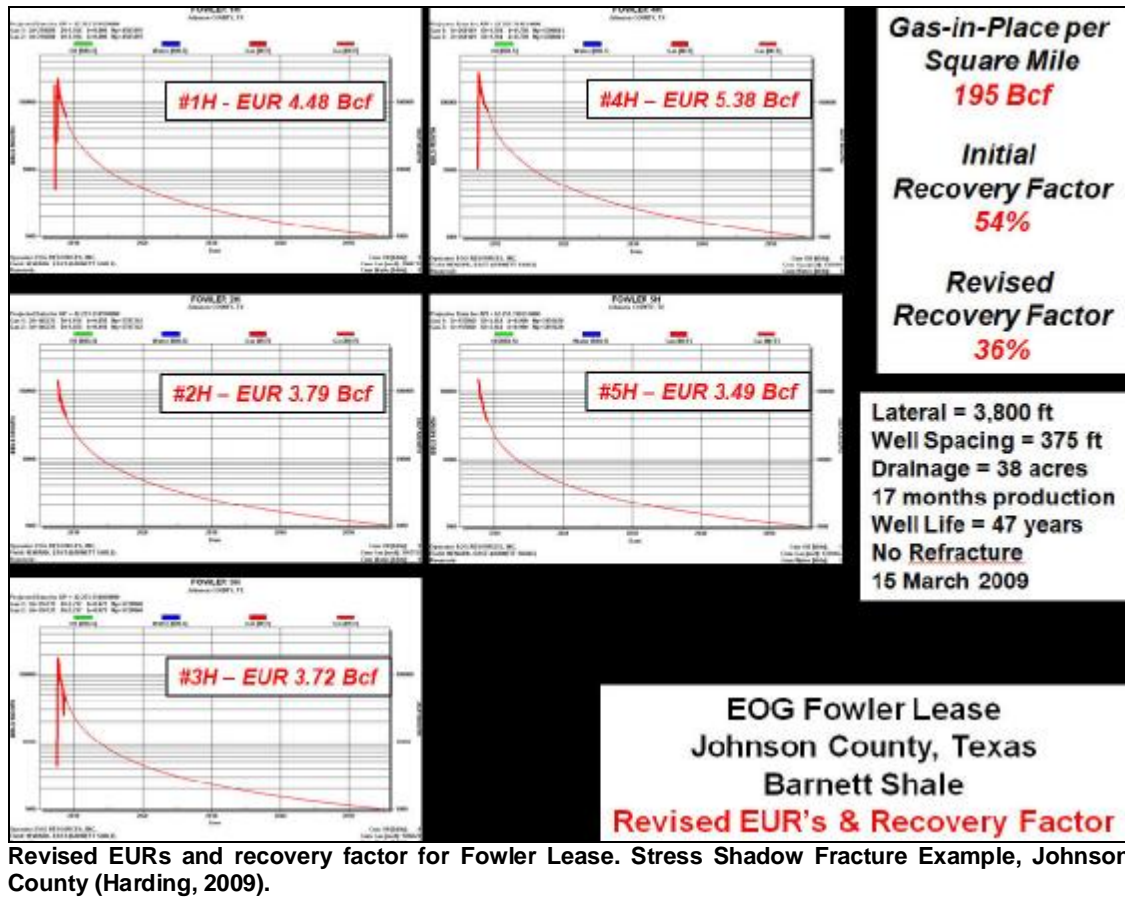
EXAMPLE

Drill five 3,000' horizontal wells on 500 ft or less spacing normal to initial MxHS (69 acre units).
 Perforate wells using interlocking pattern to exploit proppant extent (half stage spacing).
 Fracture all wells near **simultaneously** to progressively rotate the existing MxHS $\pm 90^\circ$.
 Flow back all wells only after all last stages are fraced to keep **modified MxHS** active.
 A complex grid of **intersecting** fractures should form with **greatly enhanced permeability**
and subsequent improved gas recovery.

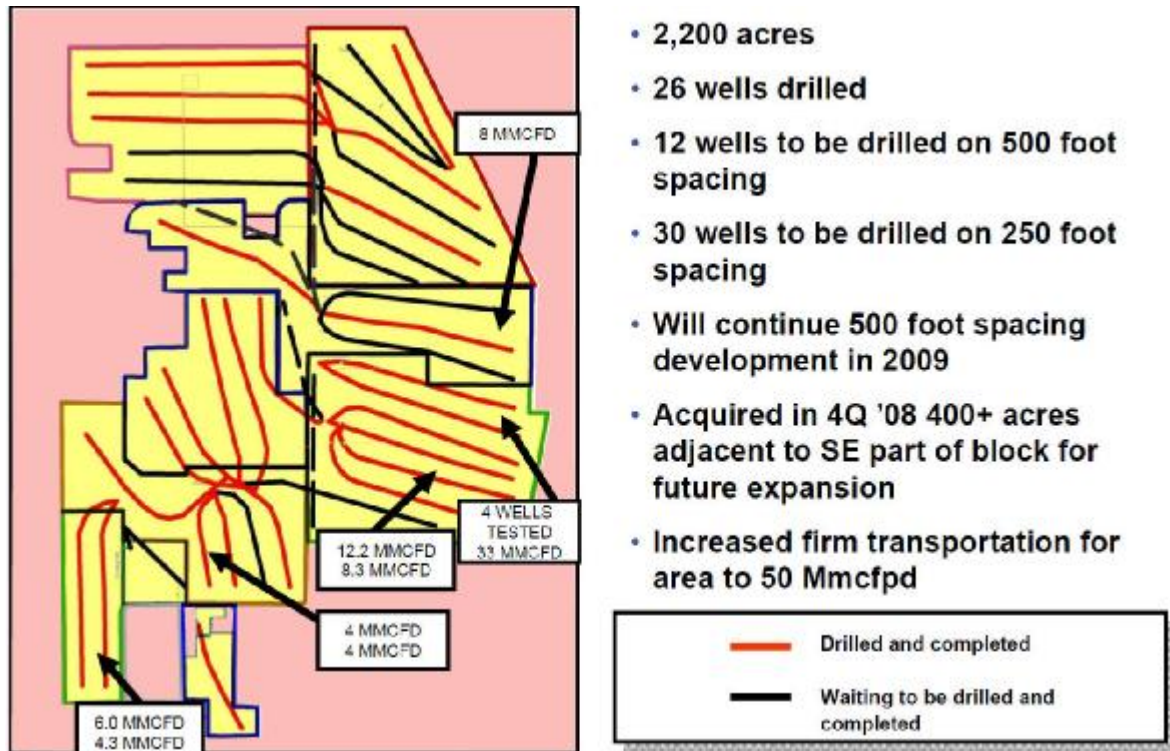


Conceptual application of stress shadow hydraulic fracturing (stress anisotropy). Red lines represent some frac energy traveling normal to initial MxHS as pressure builds without flow back to relieve pressure during simultaneous well fracture. This results in MxHS rotation forming intersecting fractures (BurnamanHarding, 2006).

Appendix 17



Appendix 18



250 ft well spacing in Barnett shale, Tarrant County using stress-shadow fracturing to improve gas recovery factor (Whitley, 2009).

Appendix 19



Urban well site with fracture water pit, Barnett shale, Tarrant County (Harding-ExxonMobil, 2007).

Appendix 20



Hydraulic fracture at small drill pad in Barnett Shale, Parker County (Harding, 2008).

Appendix 21



Hydraulic fracture, Barnett Shale, Denton County Airport. This is an example of logistics of an older well completion technology and engineering techniques. Better understanding of rock mechanics and more efficient pumping equipment have greatly reduced the amount of equipment required (Matthews, 2004).

Appendix 22



Modern hydraulic fracture of the Woodford shale, Oklahoma (Black et al, 2009).