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# Stimulating Unconventional Reservoirs: Lessons Learned, Successful Practices, Areas for Improvement

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## Abstract

The term "unconventional reservoir" has different meanings to different people. Certain reservoirs termed unconventional have a rock matrix consisting of inter-particle pore networks with very small pore connections imparting very poor fluid-flow characteristics. Abundant volumes of oil or gas can be stored in these rocks, and often the rock is high in organic content and the source of the hydrocarbon. Yet because of marginal rock matrix quality, these reservoirs generally require both natural and induced fracture networks to enable economic recovery of the hydrocarbon. Rock types in this class include shale and coalbed methane (CBM.) The term shale is a catchall for any rock consisting of extremely small framework particles with minute pores charged with hydrocarbon and includes carbonate and quartz-rich rocks. Another type of unconventional reservoir is stacked pay units exhibiting somewhat better pore characteristics than in the case outlined above but with the individual units tending to be lenticular in shape and having an extremely small size or volume. These two classes of unconventional reservoirs are amenable to well stimulation and will be the focus of this paper.

The above rock types when commercially exploited are known as resource plays. Once a low-priority, the depletion of conventional reservoirs and improving price for oil and gas has driven unconventional reservoirs to an important place in the oil and gas industry. In some regions (i.e., Rocky Mountain province), unconventional reservoirs represent the primary target of current activity and remaining hydrocarbon development. Given their unique petrophysical properties, each type of unconventional reservoir requires a unique approach to well stimulation, with often differing objectives than exist with conventional reservoir types. This paper reviews the characteristics of the basic unconventional reservoir types, lessons learned and successful stimulation practices developed in completing these reservoirs, and areas for improvement in treatment and reservoir characterization and treatment design.

## Introduction

Unconventional reservoirs amenable to hydraulic fracturing are generally hydrocarbon-rich rocks with poor matrix characteristics. By matrix is meant the inter-particle pore network of the rock mass, with pore connections determining the rate of fluid flow from pore to pore or from pore to large flow channel (i.e., solution mold, fracture, or wellbore.) In unconventional reservoirs, pore interconnections are extremely small, significantly reduced in aperture by the liquid wetting-phase, and consequently fluid flow is extremely low. In the case of oil or gas-condensate reservoirs, low mobility of the viscous liquid phase and multi-phase flow worsens the situation. Sometimes, a change in reservoir fluid mobility within the accumulation causes a loss of commerciality and bounds the limits of the pay within the field. This is the case in the in the Codell sandstone (Wattenberg field, DJ Basin, northeast Colorado) as the thermally-influenced in-situ hydrocarbon phase changes from gas to oil along the boundaries of the field. A dense network of natural fractures or a combination of fractures and solution channels with adequate apertures are generally needed to enable flow of hydrocarbons at commercial rates, and drainage of the reservoir to a significant degree. Even with an improved pricing environment, the marginal flow properties and recovery factors of most unconventional reservoirs make necessary a continuous effort to reduce costs and improve efficiencies in all aspects of drilling, completing and producing these wells. Many of the recent improvements and innovations in well completions and hydraulic fracturing have been focused as much on the cost aspect as with improving well productivity.

Othar Kiel was one of the first to recognize that unconventional reservoirs may require unconventional fracture stimulation methods.[1] He patented the technology of using shut in, flow back, bridging/ spalling steps in massive stimulation treatments to widen the zone of stimulation beyond a simple, single-plane trajectory. He proposed using very fine mesh sand (100 mesh sand) and trying to design for "partial monolayer" proppant placement/ distribution where open gaps exist between proppant/ formation-spall grains or clusters. Versions of his visionary concepts are being applied today.

In unconventional reservoirs, there is an experimental, empirical quality to fracture design selection and optimization. It is very difficult to model or simulate the permeable flow network and fracture propagation patterns with naturally fractured reservoirs, especially with the popular horizontal completion method. This difficulty has helped popularize the use of fracture mapping services such as surface and downhole tilt and downhole microseismic measurement and interpretation.

## Understanding the Nature of Natural Fracture Networks is Critical

Unconventional reservoirs exhibit different types of natural fracture systems. In one type, the fractures are open and conductive, but exist in long, narrow closely-spaced directional swarms, trending along the flanks of anticlinal or fault-related structural rock deformation. The Bakken formation in west central North Dakota is an example of this type of system.[2] These relatively high conductivity fracture swarms dictate reservoir drainage area and overall flow.[3] When these directional swarms impart high permeability anisotropy, hydraulic fracture length requirements are very minimal and long propped fractures are probably wasteful at best (see Figure 1.)[4] Another type of system is where the rock is extensively and uniformly fractured, yet the fractures have very small apertures and are nearly completely mineralized (e.g., Barnett shale model.)[5] A third system is characteristic of coalbed methane (CBM) reservoirs, in which a fracture or cleat system exists with continuous, often high permeability face cleats (often normal to the current minimum principal stress) and discontinuous butt cleats at a sharp angle to the face cleats.[6,7] Each system requires a different well completion and treatment strategy.

Multiple fracture propagation is a detriment to treatment results in conventional reservoirs with "single plane" geometry. It compromises fracture length and fosters proppant bridging at hydraulic fracture/ natural fracture nodes and loss of energy at the fracture tip.[8,9] However, in unconventional reservoirs with poor matrix quality, multiple fracture propagation is often the desired outcome. A widespread zone of fracturing can enhance drainage of the reservoir by creating permeability channels at a wide band trending in the direction of maximum principal horizontal stress.[5] The log-log plot of producing rate (or reciprocal productivity index) vs time often shows a long term linear trend (see Figure 2) – evidence that flow is dominated a anisotropic fracture-enhanced zone in the near proximity of a primary fracture trend.[10] To achieve length away from the wellbore, a massive volume of fluid must be pumped to compensate for the low fluid efficiency of the high leakoff fluid.

In the Barnett Shale model, healed fractures are believed to "reactivate" during the fracture treatment.[5] These fractures are at nearly right angles to the current day maximum horizontal stress (hydraulic fracture) azimuth and low-viscosity slick water can invade and widen the zone of stimulation away from a single fracture plane, with slip or shear events occuring along these fracture surfaces (as evinced by reflected microseisms observed in fracture mapping operations.)[11-13] The shearing action can result in permanent misalignment and residual permeability (see Figure 3) and is also believed to be a factor in the success of dynamic cavitation efforts in CBM wells.[14] The physics of this model requires a small contrast in the minimum and maximum principal horizontal stresses and reorientation of the in-situ stress field over geologic time (from time of the creation of the natural fracture network to current time.) The stimulation benefit is perhaps a combination of shear enhanced formation permeability (along a pre-existing mostly healed natural fracture network) and a limited number of propped fractures acting as a trunk-line into which the shear-enhanced permeability channels feed into. So in addition to the conventional fracture stimulation benefit of wellbore extension (the propped fracture component), reservoir permeability (and thus the reservoir itself) is enhanced or created by shear displacement of fluid-invaded natural fracture systems.

## Lessons Learned and Successful Practices

### Well Design

In exploiting unconventional reservoirs, it is generally advantageous to achieve extensive wellbore exposure using the minimum number of wells or surface locations. With some exceptions (most notably in the Fairway area of the Fruitland Coal play[15] in the San Juan Basin), wells completed in unconventional reservoirs are marginally productive and continuous improvement in drilling and completion efficiencies (to reduce the unit cost of hydrocarbon recovered) are necessary to expand develop in these reservoirs.

Horizontal wells usually offer the best way to achieve efficiency in laterally and vertically-continuous reservoirs, in which discreet layers are not separated by fracture height barriers (e.g., shale gas[16]), or in reservoirs dominated by fracture swarms (e.g., Bakken play in west-central North Dakota.) In these venues, much of the technological innovation and experimentation has been with treatment staging and diversion methods. Fracture mapping methods, such as downhole microseismic and surface and downhole tiltmeter, have been very useful for assessing the impact and effectiveness of the various methodologies. Generally, drilling in the direction normal to maximum principal stress maximizes access to fracture networks directly or when transverse-trending hydraulic fractures intersect and penetrate a cross-cutting set of sealed fractures (e.g., Barnett Shale model.) In cases in which the natural fracture network is deemed of secondary importance to productivity (for example, the middle Bakken play in the Elm Coulee field, Richland County, MT), drilling the well in the direction of maximum principle stress may be preferred in order to favor the creation of longitudinally-trending hydraulic fractures. Longitudinal fractures reduce radial convergence by maximizing exposure of the wellbore to the hydraulically-created fracture and usually eliminate the need for high-conductivity proppants.

Horizontal wells are completed with various degrees of annular isolation. Uncemented annulus or open-hole completions offer open access to fracture swarms, which may be plugged off and inaccessible if annulus is cemented. In the uncemented case, the most productive part of interval has a better chance to be stimulated or at least be open to production. Also, uncemented completions avoid perforation-related stress cages and restricted flow along the cement/ annulus perimeter until the fracture plane is encountered. This extraneous source of treating pressure drop can be very excessive, especially when large horizontal stress anisotropy exists. The source of the excess treating pressure was evaluated by Warpinski in fracture-injection experiments at the Nevada test site to evaluate the effectiveness of shaped-charge perforations.[17-18] Excess pressure drop was not observed in open-hole horizontal wells, and various degrees of drop were observed in the cased and cemented horizontal wells. Using more powerful shaped perforation charges resulted in higher treatment pressure. Mining back along the perforations showed that fractures (traced by dye) avoided the perforation tunnels entirely due to the altered, compressed rock created by the punching action of the high velocity jet charges.

Cased and cemented horizontal well completions offer greater control over fracture treatment placement and can be appropriate when dealing with relatively uniform rock in which localized natural fractures minimally enhance reservoir flow capacity. Another advantageous case may be the Barnett Shale model, in which the natural fracture system is at a high angle to the preferred fracture azimuth (i.e., maximum horizontal stress) and transverse-oriented hydraulic fractures readily connect into the natural fracture network. In horizontal wells in which cemented completions are warranted or desired, sand jet perforating is sometimes preferred. It removes formation material and thus avoids creating or worsening the stress cage around the perforation tunnel and wellbore. Placing acid soluble cement in the annulus adjacent to the perforation interval and then subsequently dissolving it with hydrochloric acid has also been effective at mitigating near-wellbore restriction in cemented horizontal wells.[19]

Discontinuous, multilayer intervals such as stacked, fluvial-dominated sandstones are best completed with vertical wells (through the pay section) in multistage treatments. The individual lenticular reservoirs have drainage areas sometimes averaging 10 acres or less, and high well density is needed to effectively exploit the resource. Pad locations, in which multiple S-shaped wells (sometimes as many as 32 per site) are drilled in simultaneous drilling, completing and producing operations (Simops), serve to minimize surface disruption and maximize efficiency in frac-factory type operations.

**Treatment Staging and Diversion Methods**

Much of the intellectual focus and innovation in unconventional reservoir exploitation has been applied in developing techniques and equipment to maximize treatment coverage with minimal downhole intervention. Some methods and tools are specific to horizontal wells or vertical wells and some apply to both. Some have been used for over 40 years and others are relatively new.

***Primary Application: Vertical Wells***

Introduced in 1961, limited entry perforating and mechanical-plug treatment diversion and stage isolation is a time-honored method[20] and well suited for multi-zone vertical well completions. Using the choke-like characteristics of shaped-charge or bullet created perforations, treatment injection rate is adjusted to build a desired level of excess pressure in the casing, enabling diversion from lower-stressed to higher-stressed zones.[21] Over the years, the physics of limited entry treatments have been studied (e.g., perforation erosion[22]) and various guidelines have been developed, regarding parameters such as minimum perforation friction, maximum gross interval length per treatment and the like, for improving stimulation coverage of multiple zones. Perforation breakdown may be the most important determinant of limited entry treatment success. Figure 4 shows the results of tracer surveys comparing near-wellbore proppant placement of various treatment stages in a well in the Williams Fork formation, Piceance Basin.[23] Less than 2/3 of the perforated intervals were treated in Stage 1, in which perforation breakdown methods were not used. In Stage 3, a pre-frac ball-out treatment improved zonal coverage but the lowest two intervals were left untreated. In Stage 2, all zones were propped as each interval was separately isolated and broken down. Fracturing and breaking down each zone is not practical in everyday operations, so alternate breakdown methods are used. In one method, the lowest zone is selectively perforated and broken down with borehole fluid, usually water. Then, the remaining intervals are perforated, the perforating gun is removed from the well and 250 to 1000 gallons of hydrochloric acid are spearheaded as the first stage of the fracturing treatment. Injection invariably occurs in the broken-down perforation set, allowing the acid to wash across, penetrate and break down the uphole perforations. This method is effective without ball sealers, but dissolvable ball sealers have been developed to assist in formation breakdown in lieu of or to augment this technique.[24] Flow-through composite bridge plugs have also served to advance the limited entry process.[25] These plugs are used to isolate treatment stages and enable continuous load fluid recovery from all previously-treated intervals during any flowback and pre-cleanout production period.

Introduced in 1965, the ball and baffle-ring diversion method is still widely applied.[20] It is based on dropping a drillable ball at the end of a treatment stage. The ball seats in a baffle ring which is inserted in a casing collar above the active perforations, isolating the hole from that point downward. Holding pressure on the well to keep the ball in place, perforations are shot in uphole interval(s), which are then treated. This process is limited to about 4 treatment stages because of the need for progressive changes in the ball and baffle-ring sizes.

Stress-induced diversion uses the increased compressive in-situ stress imparted by residual hydraulic fracture aperture of a previously-treated interval to divert a new treatment to an interval sufficiently spaced away from the stress window. Mechanical isolation plugs are not used. The physics of this process was described by Warpinski and Branagan.[26] This was a common technique in many tight gas vertical well completions[27] and has been used lately as a component in horizontal well completions.

A novel staging method applied recently in multi-zone completions is Just In Time Perforating (JITP.) In this process, a wireline–conveyed perforating gun remains in the well during fracture stimulation to sequentially perforate individual zones. Buoyant ball sealers are dropped at the end of treatment stages to isolate (ball off) treatment zones. As the ball sealers bridge on the active perforations, new perforations are fired in an adjacent uphole zone, into which the subsequent treatment is immediately performed. This sequence is repeated until the capacity of the perforating gun (which is limited by the height of the gun lubricator) has been reached.[28] With JITP, up to 11 zones have been treated per gun run, up to 22 individual frac jobs have been done in a day, and over 50 treatments have been done per well. This process is very amenable to multiple-well pad locations, in which activity can switch from well to well after a gun run is complete, improving efficiency. Figures 5-7 show data from a JITP project in the Mesaverde formation, Piceance Basin, Colorado. Five wells were treated from the same location in 253 separate treatment stages over a 17-day period.[29] JITP offers the potential to select-treat individual zones rapidly and economically. To date, it has been performed on over 80 wells in more than 2700 separate treatment stages.

Another recently applied method for selective multiple-zone stimulation is annular coiled tubing (ACT) fracturing. Sand-jet perforating is performed via a coiled tubing string, and the fracturing treatments are conducted down the casing/ coiled tubing annulus. Sand plugs are normally used for stage isolation (mechanical plugs have been used but this process is restricted due to patent protection.)[30] ACT has been applied in many CBM reservoirs and the unconventional diatomite oil play in California, in which it outperformed limited entry and mechanical plug methods.[31] In that application, up to 18 separate ACT fracturing stages were done per well, covering over 1000 feet of net pay.

Casing conveyed perforating has been used with isolation valves in cemented horizontal and vertical wells to enable continuous operation in multiple treatment stage applications.[32] Guns and sliding sleeve-operated flapper valves are hydraulically actuated on commend from the surface in this patented process. It has been used most recently in non core-area Barnett Shale horizontal well applications in which lower injection rate treatments were designed to avoid fracture growth into the water-productive Ellenberger formation. Up to 28 individual treatment stages per well have been done using this method.

A related technology for cemented wells is a casing-conveyed system featuring a dart-actuated sliding-sleeve mechanism to gain access to multiple pay intervals in continuous treatment operations.[33] The opened sleeve exposes ports to the cement sheath, yet in the lab and field, formation breakdown has been shown to occur at minimal pressure without the need to perforate. The number of treatments stages is limited only by component cost and post-treatment cleanout considerations and has currently been limited to vertical well applications.

***Primary Application: Horizontal Wells***

Extensively used in horizontal wells configured with an uncemented annulus, external casing packers have been used to segment the well into smaller sections for selective stimulation in a continuous operation. The packers can be of various types, including mechanical, swellable[34] and inflatable. Within the casing string and between packers, ball or dart-actuated sliding sleeves are inserted as dual opening and shut-off devices.[35] Treatment stages are limited to about 10 by the ever changing ball size requirements to sequentially activate the sliding sleeves.

Another widely-used technique for stimulating horizontal wells with an uncemented annulus, annular friction pressure has been used in combination with ball sealers and sand slugs for treatment diversion inside and outside of the treating string. Its effectiveness has been documented in the middle Bakken play in Richland County, Montana and is especially suited for cases in which the toe section of the well treats preferencially.[36] The annular clearance between liner/casing and drilled hole needs to be minimized to take full advantage of this tactic. Figure 8 is a graph of friction pressure vs rate for various annular configurations showing the impact of reducing the annular clearance on pressure drop and diversion capability.

Flexible sand plugs have been developed for stage diversion.[37] Deformable and conventional proppants are mixed together at a specific ratio, added to fracturing fluid at a high concentration (14 lb/gal of fluid) and pumped at the end of a treatment stage to fill across and uphole of the stimulated zone. With sufficient plug length, the flexible plug is very resistant to displacement, possessing a yield pressure in the range of 9000 psi. After all treatments are complete, the plugs are easily circulated from the well using a vortex nozzle. This application has been combined with coiled tubing deployed sand-jet perforating in cased and cemented horizontal well completions.

A method developed for multiple-stage stimulation in open-hole horizontal wells uses the Venturi effect of a high velocity fluid jet focused on a specific point at the wellbore to favor hydraulic fracture propagation at that point.[38] The jetting fluid is normally conveyed by a coiled tubing string. The fracturing fluid is pumped down the open-hole/ coiled tubing annulus. This method is most likely to be effective when horizontal stress anisotropy is absent or very low.

Other iterations and combinations of the above technologies have been used effectively. An example is pumping down perforating guns and bridge plugs with gelled water in multiple-stage fracture stimulation of uncemented horizontal wells. This technique has been used in combination with external casing packers in the Bakken play in North Dakota.

**Fluid and Proppant Design**

Reservoir properties are important in selecting the best fracturing method. In shales, coals, and many tight gas sand intervals, natural fractures/ fissures/ cleats are the dominant flow conduits for liquids and gases. These rocks are characterized by very low leak off to the matrix. Because of the fissures, pressure dependent permeability and leak-off are often encountered during fracturing treatments. Fracturing fluid viscosity has a dominant influence on the leak-off to these pressure-sensitive fissures – low viscosity enhances and high viscosity diminishes the leak-off. Leak off enhances the potential for a wide zone of stimulation, including enhanced permeability due to shearing movements along the invaded fissure surfaces but increases the risk of proppant bridging at the fissure / hydraulic fracture nodes or intersections.[8,39]

Water is used as a base fluid in most unconventional reservoir treatments. Water is economical and can be re-used, especially if chemical quality control standards are broad, as in waterfrac applications (i.e., non-gelled, non-viscosified water). Unconventional reservoir rock is usually chemically un-reactive to water as pore throats are too small to accept much fluid and the majority of flow and leak off occurs to fractures. Mobile or swelling clay minerals are not usually a component of fracture-fill material (or of matrix pore-wall linings.) Water becomes an issue when its physical properties, high density and capillary pressure gradient in small pore networks, render it immobile in low energy systems.

With several notable exceptions, there has been a strong trend to using waterfrac or slick water as the primary fracturing fluid in treating unconventional reservoirs.[40] Plain or slick water mitigates the plugging of fractures from gel residue. Water leaks off easily to fracture networks to widen the zone of stimulation by inducing shear fracture enhancement of marginal or cemented natural fracture networks. Proppant is important to stimulation results[41] by extending the effective wellbore radius and serves this purpose by propping open at least the main part or "trunk" of the hydraulic fracture system. Proppant settles rapidly in waterfrac systems, forming a proppant bed along the bottom of the fracture; an equilibrium bed height is quickly established, then proppant is transported along the top of the bed toward its terminus. Within the bed, propped width is equal to the pumping width achieved during the pad stage of the treatment, resulting in a conductive multi-layer proppant pack. Perhaps more importantly, a highly conductive, open channel (an unpropped wedge) can persist along the top of the settled bed.[9,42] The waterfrac/ sand bank method is particularly effective in small drainage area fluvial reservoirs with limited downward fracture height growth, as exist in the Piceance Basin Williams Fork formation.

In the unpropped wedge scenario, fine-mesh proppants can produce similar and sometimes better results as compared to commonly-used 20/40 mesh proppant since smaller proppant particles have less tendency to bridge and pack off in the fracture. In fact, 40/70 mesh has been a preferred proppant type in stimulating the Barnett Shale and many other unconventional reservoirs. The properties of an unpropped wedge are likely to be insensitive to the material characteristics of the proppant. Consequently, wells treated with non API-spec proppants may produce similarly to wells treated with standard proppants. If the unpropped wedge mechanism is validated in a particular application, formerly substandard sources of proppant could be approved for use, reducing demand on the limited supply of high quality 20/40 and 40/70 mesh sand.

Proppant-induced pressure increases (PIPI) and total treatment screenouts are generally undesirable in unconventional reservoir treatments. Most PIPIs are the result of proppant bridging near the wellbore.[39] When near-wellbore bridging happens, the ability to propagate and extend fracture growth far away from the wellbore is lost. Also, the proppant bridging may eliminate the potential for sustaining a high-conductivity open channel at the top of a settled proppant bed. An exception to this rule is the intentional use of high-concentration proppant slugs to induce diversion at the end of treatment stages in uncemented horizontal well treatments.

Although there is some concern in regard to the molecular weight characteristics of polyacrylamide (PA) friction reducers used in slick water applications, they are generally used at very low concentrations, sometimes as little as 0.25 gal/1000 gal of water. Recently, delayed gel-breaking additives have been used that degrade PA without effecting friction reduction properties.

Over-pressured or higher-energy reservoirs usually have the potential for high sustained post-treatment flow rates. High and controlled flow rate facilitates fracture fluid clean-up and the use of breaker-laden high-viscosity crosslinked fluids if warranted.[43] Under-pressured reservoirs are more prone to clean-up issues, especially with high gelant loading fracturing fluids, and often respond better to gas-assist, foam, slick water (low viscosity) and oil. In cases of ultra-low reservoir pressure, all-gas treatments have been effective, such as the $CO_2$ dry frac process[44], $N_2$ coiled tubing fracturing treatments in the Horseshoe Canyon CBM[45-46] and Devonian Shale plays.

A blend of the above methods that has been widely used is the hybrid treatment method, using a low-viscosity water pre-pad to create fracture area, then a viscous crosslinked gel to transport and place proppant.[47] The benefits of extensive stimulation of fracture systems are combined with superior proppant placement, especially vertically, in the "trunk" fracture(s) exhibiting sufficient width to accept proppant.

One-hundred mesh sand is used as a scouring agent, proppant and limiter of fluid loss to crossed fissures. Being extremely fine, it can abrade and enlarge narrow flow-path restrictions as exist in the annulus of the cement sheath and drilled hole, and may be able to penetrate fracture branches and resist fracture rehealing. As a bridging agent at hydraulic fracture/ fissure nodes or intersections, 100 mesh sand enables the propagation of additional primary hydraulic fracture length and minimizes the potential for proppant bridging at hydraulic fracture / cross-fissure nodes.[48-49]

Ultra-lightweight proppant (ULWP) has been widely used in conjunction with waterfracs.[50-51] ULWPs possess grain density as low as 1.05 specific gravity, providing minimal density contrast to fresh water and near-neutral buoyancy when light brines are used as the fracturing fluid. Because of the small density contrast between the proppant and carrying fluid, grains of ULWP proppant settle slowly and can be transported farther into the vertical and lateral extremities of the hydraulic fractures. Although relatively expensive, ULWP is usually used in low, dispersed concentrations, with the intension of creating partial monolayer-like proppant placement, in which open channels exist in the fracture around clusters or individual grains of the ULWP. ULWPs are somewhat deformable and resist embedment into the fracture faces, but are prone to excessive flattening at high temperature (i.e., > 220-250° F) and closure pressure (i.e., > 5000-6000 psi.), limiting their application to moderate true-vertical well depths.

Use of microemulsion chemicals are commonly used to enhance permeability to gas in the fracture face area of the reservoir.[52] These products seem to be most effective in high oil/gas ratio cases.

Using recycled water in large waterfrac programs results in degraded water quality and the need for scale and bacterial growth control. Consequently, scale inhibitors and biocides are commonly-used additives in waterfracs.[53]

**Design Guidelines and Rules of Thumb**

Often, post-frac well performance in unconventional reservoirs correlates more strongly and directly with fluid volume than with proppant volume. In Williams Fork completions in the Piceance Basin, several operators have improved well productivity by doubling fluid volume and maintaining the same proppant volume by cutting the proppant concentration in half. Reducing the proppant concentration also mitigated proppant induced pressure increases, which may also be a factor in the improved results.

Due to the complexity of the process, there is a general lack of reliance in using hydraulic fracture simulators to design and optimize fracture treatments in unconventional reservoirs. Very often, empirically-based, sometimes arbitrary rules of thumb (e.g., lb prop/ net foot of pay) are used to design the treatment.[54]

**Proppant Flowback Control**

With sand-banked proppant placement, lack of fracture closure at the top of the proppant bed, and high flow velocities due to the high conductivity on the top of the fracture, mobilization of proppant and its flowback into the wellbore can result. The most common way to mitigate this problem is over-flushing, the practice of pumping a stage of plain water after all proppant has been displaced from the wellbore. Although a normal over-flush volume is 10 to 50 barrels of water, one Williams Fork/ Piceance Basin operator over-flushes slickwater treatments with 150 to 200 barrels of water per stage. The effect on well productivity has been neutral and proppant flowback has been arrested. Resin coating of proppant has also been effective in controlling proppant flowback, as well as using deformable proppant blended with conventional proppant.[55]

**Treatment Flowback and Produced Water Management**

Treatment flowback/ load fluid recovery is another area of focus, particularly in multi-layer reservoirs such as exist in the fluvial sand deposits of the Piceance Basin and Pinedale Anticline. These unconventional reservoirs are characterized by numerous discreet sand bodies (20 or more) over a large vertical extent (1500 to 5000 ft.) Even with limited entry treatment application, multiple treatments are needed to effectively stimulate as many sands as possible. Recovering load fluid is usually necessary to restore gas permeability and enable well productivity, but multiple shut-in periods complicate the process. Treatment flowback/ load recovery options fall into three diverse categories – immediate, deferred and long-term shut-in.

Immediate flowback following treatments is still the most common method applied in stimulation of unconventional reservoirs. This enables water to be quickly displaced from the invaded area of the reservoir and restoration of permeability to the hydrocarbon phase. It risks the creation of a water block at the fracture faces if water is allowed to drop out of the wellbore system during shut-in periods and resaturate the rock with water at a lower pressure/ energy state. Resaturation risk has been partially mitigated by separating previously-treated intervals with flow-through bridge plugs. Flow-through bridge plugs enable continued flow from all zones during all clean-up and production (flow back) periods and their use has improved overall production results in multi-pay environments such as the Jonah field of the Greater Green River Basin.[25]

Recently, in higher energy/ reservoir pressure cases, some operators have been deferring fracturing fluid flowback until all zones have been treated, stage-isolation plugs and debris are removed from the well, and production tubing if applicable is installed with the well ready to flow to the gas sales line. This method enables bottomhole flowback pressure to be at least as high as the initial reservoir pore pressure, reduces the risk of resaturating previously cleaned-up intervals with water, and has been shown in the Pinedale Anticline and Piceance Basins to provide comparable production rates to offsetting wells flowed and cleaned up after each treatment stage, but with less time and cost.

Shut in strategies to reverse water-block damage have worked well in the case of low-energy, low-pressure gas wells that are killed by pumping a large volume of treating fluid. If the source of water is simply the finite amount pumped during the treatment (the fractured interval is a closed "dry"system with no mobile water), gas will eventually flow into the wellbore during the shut-in period, replacing water. Water will eventually imbibe deeply into the reservoir, driven by the capillary pressure gradient. This restores gas permeability in the area of the reservoir along the fracture face, as well as dewatering the fracture. This method has been applied extensively in the Codell formation in the DJ Basin of Colorado. Following the standard 3000 barrel re-fracturing treatment, many wells recover only 50 to 100 barrels of load water and then quit flowing. It has been found that shutting in these wells for one to two months following the treatment and allowing pressure to build up in the wellbore removed the water block and enabled commercial production.

Liquid loading during the production phase is a major impediment to hydraulic fracture sustainability. Water invades the pressure drained region of the fracture faces and can dramatically reduce the permeability to the flowing hydrocarbon phase/ gas. Fracture effectiveness can plummet from excessive pressure drop within the reservoir in the vicinity of the fracture due to the water block.[43,56] Production operations can significantly affect sustained water/ liquids removal from the wellbore and fracture, and thus well productivity. Decisions regarding tubing landing (in relation to perforations), shut-in periods, tubing sizing and lift-assist mechanisms and techniques are examples of how production engineering can impact results.

**Simultaneous Fracturing**

Simultaneous fracturing or simulfracs is the performing of fracture treatments on two or more offsetting wells at the same time, with the wells in a common interval and along the same trend as the expected fracture orientation. Simulfracs have been applied to gain some control over the fracture propagation process, by preventing runaway fracture growth into a drained portion of the reservoir or to an offsetting wellbore[57] (pressure sink), or to widen the zone of stimulation. In the former case, this method has been used to achieve stimulation in the Codell formation in refractured wells that had previously fractured into offset wells and as a result lost all well productivity. The latter case has now been effectively applied in the Barnett and Fayetteville Shales with some of the best performing wells in those plays treated in this manner.[58-60]

**Remedial Treatments**

Re-fracturing is a successful tactic in exploiting continuous-deposit unconventional reservoirs. The Codell formation in the DJ Basin of northeastern Colorado is the most significant example of this. It is a thin, extremely low permeability, clay-rich lower shoreface sandstone deposit present throughout the Wattenberg Field. Codell wells are drilled on 40 acre spacing, yet production analysis consistently indicates drainage of 10 to 20 acres per well. A linear flow signature (i.e., long term half-slope trend in the rate vs time plot) evinces the case for flow mostly limited to an elliptical area near the original hydraulic fracture. Fault displacements or condensate blockage (oil-gas ratio is 40-50 bbls/mmscf) may be the mechanism responsible for this lateral reservoir restriction. Regardless, there exists a permeability barrier related to the marginal rock characteristics of his zone. The drainage asymmetry creates a prime opportunity for re-fracturing treatments[61-63] – provided the reduced pore-pressure in the ellipse around the original fracture is sufficient to create a stress field alteration within the drained area.[64] In the Codell, sufficient pore pressure reduction usually occurs within three years of the original treatment; subsequently, the fracture azimuth reorients to the narrow sides of the ellipse, taking the shortest path to the undrained portion of the reservoir.[65] Because of substantial downward height growth during even low-rate frac treatments, proppant settling as experienced with banking type fluids is an undesired outcome and a high-viscosity fracturing fluid system possessing great proppant transport and yet with relatively low gelant loading for enhanced cleanup, has proven to be a very successful practice.[66] Using the high viscosity fluid system, incidences of communication to offsetting wells has been mitigated as well.[67] In the Barnett Shale, waterfrac fluid systems have worked well in re-fracturing treatments.[68]

In cases of water blocking, gelled fluid blockage and generally-poor treatment fluid clean-up, various remedial treatment systems and strategies have been effective. One of the most effective all-purpose methods is injection of $CO_2$ into the formation. $CO_2$ dissolves into the water phase, reduces interfacial tension between the water phase and rock, and lowers water pH to assist in thinning or breaking residual gelant material. Successful application has been documented in the Greater Green River Basin of Wyoming.[9,69]

**Coalbed Methane (CBM)**

With coal as well as with shale gas, much of the gas in place can be adsorbed onto the surface area of rock micropores and held in place by pressure. Pumping or flowing water out of the reservoir is necessary to reduce pressure and allow the release of gas into the cleat or fracture network. In high energy reservoirs (i.e., high kh and pore pressure), dynamic cavitation, the pumping of fluid (usually compressed air) into the reservoir and then surging the well back to produce liquids, gas and coal, is still the most effective method to stimulate the reservoir and enhance dewatering. The impact of the process is much more extensive than the enlarged wellbore cavity of 4 to 5 ft due to the creation of shear fractures at angles to the face cleats that extend tens of feet from the wellbore.[14] The effect is also enhanced by post-injection flowback and recovery of coal particles/ pieces, much as prescribed by Kiel. Dynamic cavitation has been most effectively applied in the Type 3 Producing Area coal of the San Juan Basin in the Fruitland Coal.[15]

In lower pressure, high-kh CBM reservoirs, pumping produced water at high rate (e.g., 0.5 to 1 bbl/min/ft of coal) for about 30 minutes (known as a water enhancement treatment) is sufficient to stimulate the well; wellbore skin is often reduced to 0. These treatments are intended to clean out or by-pass plugged cleats in the near-wellbore area. The best example of successful water enhancement treatments is the Ft.Union coals of the Powder River Basin of Wyoming. Small sand fracs with produced water work better in the lower permeability intervals of the Ft.Union.[70]

Some CBM reservoirs are already dewatered, produce dry gas and possess low pressure. Liquid-based treatments have been generally unsuccessful in these types of coal, and $N_2$ treatments, similar to methods used for years in the Devonian shales of the Appalachian Basin, appear to be most effective. The Horseshoe Canyon play in Alberta is an example of this reservoir type and has been effectively stimulated with coiled tubing-isolated $N_2$ fracs to stimulate numerous thin zones.[45,46] Well productivity is very low in these reservoirs (e.g., ~100 mscf/d) and efficiency and general cost containment is essential. A new innovation that has been successful in the sub-pressured Niobrara Chalk play in northeast Colorado and could be applied here is using high-quality $N_2$ mist with a slurried concentrate of ultra low density proppant, enabling hydraulic fracture flow channels to be propped open a significant distance from the wellbore with a residue-free medium.

In mapping hydraulic fracture patterns and traces in CBM intervals in which the fractured area was mined through, Diamond noted Portland cement invasion 100 ft away from the wellbore in the Black Warrior Basin.[71] The cement was apparently sourced from the primary cement job done on the well. This shows the influence of cleat system on permeability and documents the consequences of invasion and plugging of reservoir flow channels. The risk of cleat plugging from cement and gel solids should be minimized in all cases and avoided entirely in low energy situations (i.e., low kh, low pressure.)

Coalbeds may be prone to disintegration if too much energy or flow rate is applied during the treatment. Often, because of slippage at coal/ bounding zone interfaces[72], most of the treatment stays confined within the coal interval. This is evinced by bottomhole treating pressure gradient in the vicinity of the vertical overburden gradient (1.0 psi/ft.) Because of the pre-existing fracture system and high treating pressure due to fracture height containment and flow-path blockage, extreme fracture complexity is routine in many CBM applications. An injection rate limit of 1.5 to 2 bbl/min/ft of coal has been suggested as a maximum rate to avoid excessive shear degradation and massive coal particle blockage both during and after the treatment.[55] Regardless, the degree of near and far-field restriction from one seam to the other and the resulting effect on bottomhole treating pressure can be significant and unpredictable (see Figure 9.) Consequently, in multiple-seam completions, limited entry treatments are rarely advisable and select-zone stimulations are preferred.[73] Treatment screenouts due to excessive proppant bridging are often very damaging to well productivity and generally should be avoided.[74] In some cases in which complex fracturing behavior is expected to compromise treatment results, indirect fracturing has been proposed, in which bounding zones adjacent to coal layers are perforated, with fracture growth extending from competent rock into the coal.[75]

With the advent of high efficiency, low polymer systems with high gel breaker concentrations, there has been significant usage of crosslinked gel in CBM fracturing treatments.[76] Proppant transport through the tortuous flow channels often present in CBM treatments is much improved with viscous fracturing fluid systems. These fracturing fluid systems are best used in higher energy reservoirs (i.e., high reservoir pressure and/or moderate to high permeability) that can sustain a high initial gas flow rate during cleanup. Hybrid treatments using water pre-pads have been proposed for use in lower energy reservoirs that show a high tendency for premature treatment termination due to fracture complexity.[77]

**Unconventional Oil Reservoirs**

In unconventional oil reservoirs, the pump and soak method has been used to recover incremental oil locked in the tight matrix of the rock. In these treatments, a large volume of non-viscous water is pumped, usually into previously-produced wells, and then the wells are shut in for several weeks to enable the water to imbibe into the tight matrix and displace oil into the natural fracture flow channels.[78] The benefits of this approach have been documented in both vertical and horizontal wells in the Austin Chalk, Niobrara and Turner formations.[79]

**Predicting or Measuring Reservoir Quality and Treatment Effectiveness**

Measuring completion and stimulation effectiveness is very difficult in unconventional reservoirs in which horizontal or multiple stage completions have been applied because of multiple production entry points and separate reservoir compartments. Conventional single-layer analysis techniques can be used but the result is very speculative at best.[10,80] Other methods use three or more production-log surveys to assign interzonal flow rate contributions and then apply analytic or numerical techniques to estimate kh, effective fracture length and drainage area/volume.[81,82] The lack of resolution and confidence with infrequent and small sampling and often suboptimal condition for liquid removal (tubing must be landed above all perforations) limits the reliability of these efforts as well. Consequently, most evaluations usually consist of comparing the cumulative hydrocarbon production of differently completed wells at fixed periods of elapsed time (e.g., 90 day cumulative production.) In this way, the relative effectiveness of different techniques can be assessed. These efforts often provide important insights, especially when the sample size of wells is very large, but can be misleading when sample size is small. In any case, comparative analysis does not provide insight into relative contributions of reservoir and fracture flow properties. The development and refinement of technologies such as distributed temperature surveys (DTS) offer the potential to obtain a large amount of continuous flow rate and bottomhole pressure data on a layer by layer basis to effectively use analytic methods.[83,84] These measurements will need to be complimented with pre-completion techniques to obtain initial reservoir pressure, which is a very necessary input in drawdown analysis.[80]

Useful and diagnostic rules have been proposed by Barree et al to enable accurate interpretation of diagnostic injection/ falloff tests (DFIT.)[85] DFIT is a type of impulse test and consists of injecting a small amount of water (e.g., 250 to 2000 gallons) to fracture an interval and then shutting the well in to observe post-injection pressure falloff. In many unconventional reservoirs, DFIT tests have replaced the larger-volume mini-frac treatments as proposed by Smith and Nolte in their classic work on treatment pressure interpretation. Often, reservoir parameters such as in-situ stress, reservoir kh and initial reservoir pressure can be derived with DFIT tests and qualitative if not quantitative assessments can be made regarding the commercial feasibility of performing large scale fracturing treatments in specific intervals. However, ultra-low water mobility in ultra-tight shale reservoirs often preclude effective use of DFIT in shale gas reservoirs as the injected fluid leak-off rate is exceedingly low into the matrix. Also problematic is the situation in which the massive stimulation itself may substantially enhance reservoir permeability by mechanisms previously discussed.

**Needed Improvements in Unconventional Reservoir Fracturing Technology:**

1. Fracture simulators that provide rigorous modeling of proppant banking and placement of low-density proppants.

2. Modeling of hydraulic fracture treatments in horizontal wells taking into account in-situ stress field and wellbore orientations, the presence or lack of casing string and degree of annular isolation and pre-existing fracture swarms, and the resulting impact on well productivity. The prime benefit would be to enable “what if” scenarios regarding treatment design, treatment staging efforts and the like.

3. Modeling of discontinuous, anisotropic petrophysical systems, from fracture propagation and production simulation standpoints.

4. An economical low volume pre-treatment method to assess shale reservoir permeability as is done in low-permeability sandstones with the DFIT process described by Barree et al.

5. A method to identify and map the proppant distribution within the fracture.

6. Production (rate pressure) analysis of multi-layer wells using continuous, high frequency data acquisition, along the lines of DTS efforts, but with enhanced resolution, especially in the presence of water flow. This would be helpful in accessing analytically stimulation effectiveness and reservoir flow capacity (kh, xf.)

7. Further advancements in water mobility and gas permeability enhancing chemicals that reduce liquid trapping at the fracture face.

8. Enhancement in the properties of ultra lightweight proppants (ULWP) to withstand high closure pressures and temperatures common in many basins (e.g., extending the application of 1.05 specific gravity material to 300 deg F and 8000 psi closure.)

9. Matching the fracture geometry to the anticipated drainage area, as in the case of lenticular reservoirs. Determine if hydraulic fractures can link disparate isolated reservoir pay pods.

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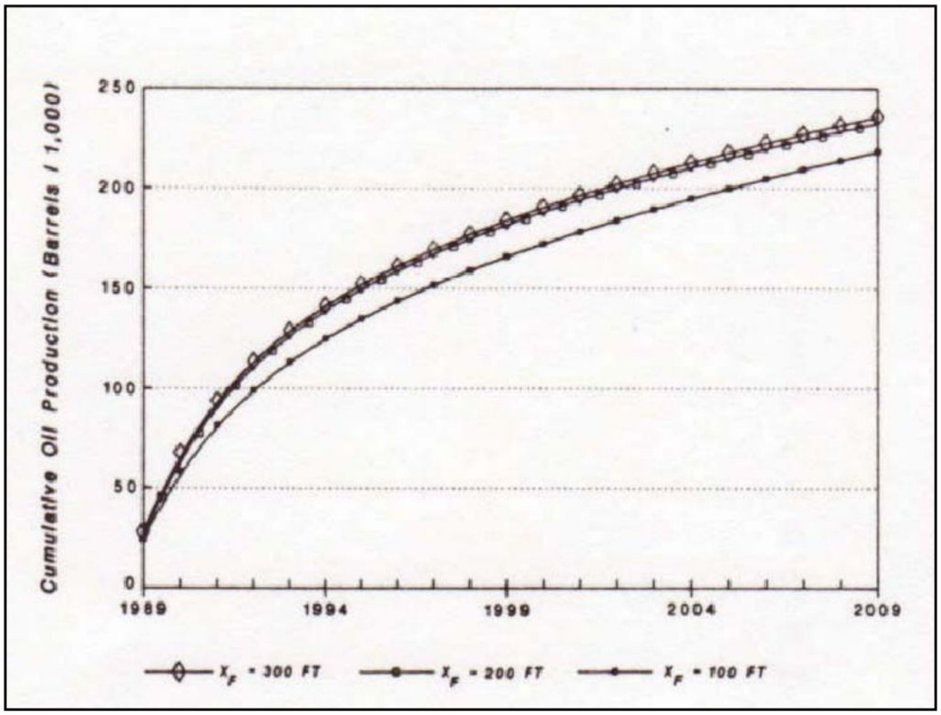


Figure 1: Diminishing Returns with IncreasedFracture Length in Anisotropic Bakken Reservoir (from reference 4)

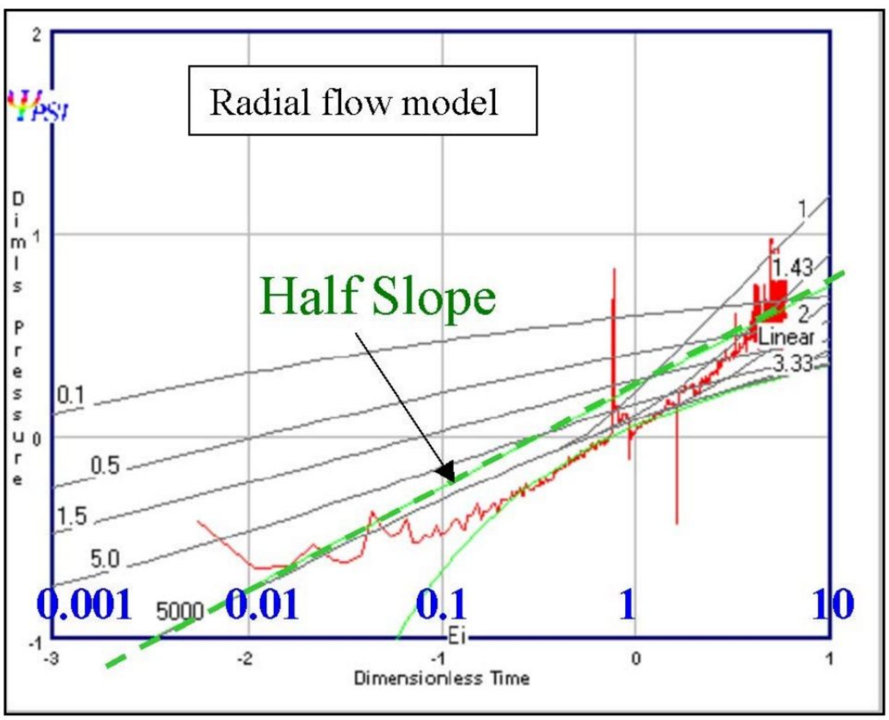


Figure 2: Production Diagnostic Plot Shows Formation Linear Flow Behavoir (from reference 10)

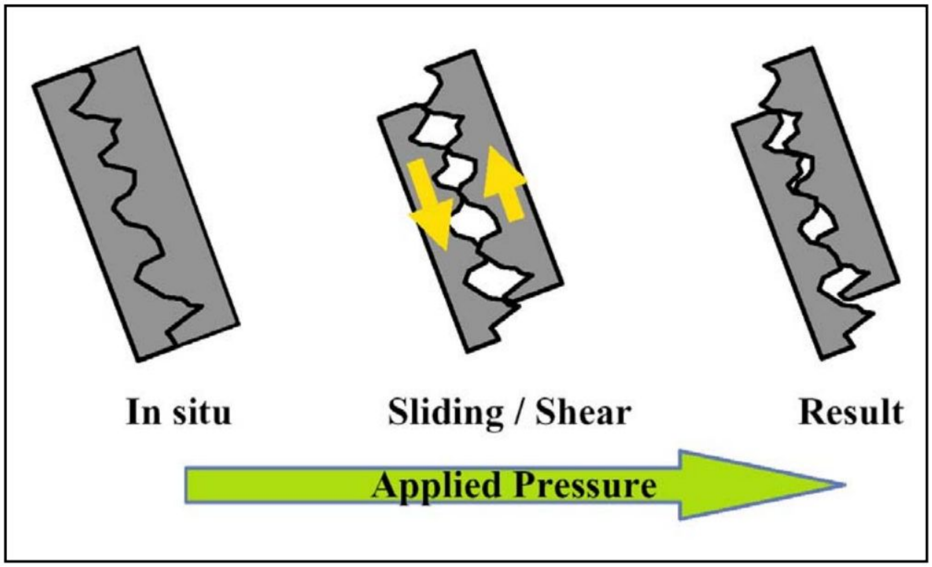


Figure 3: Shear Displacement Results in Residual Permeability (from reference 12)

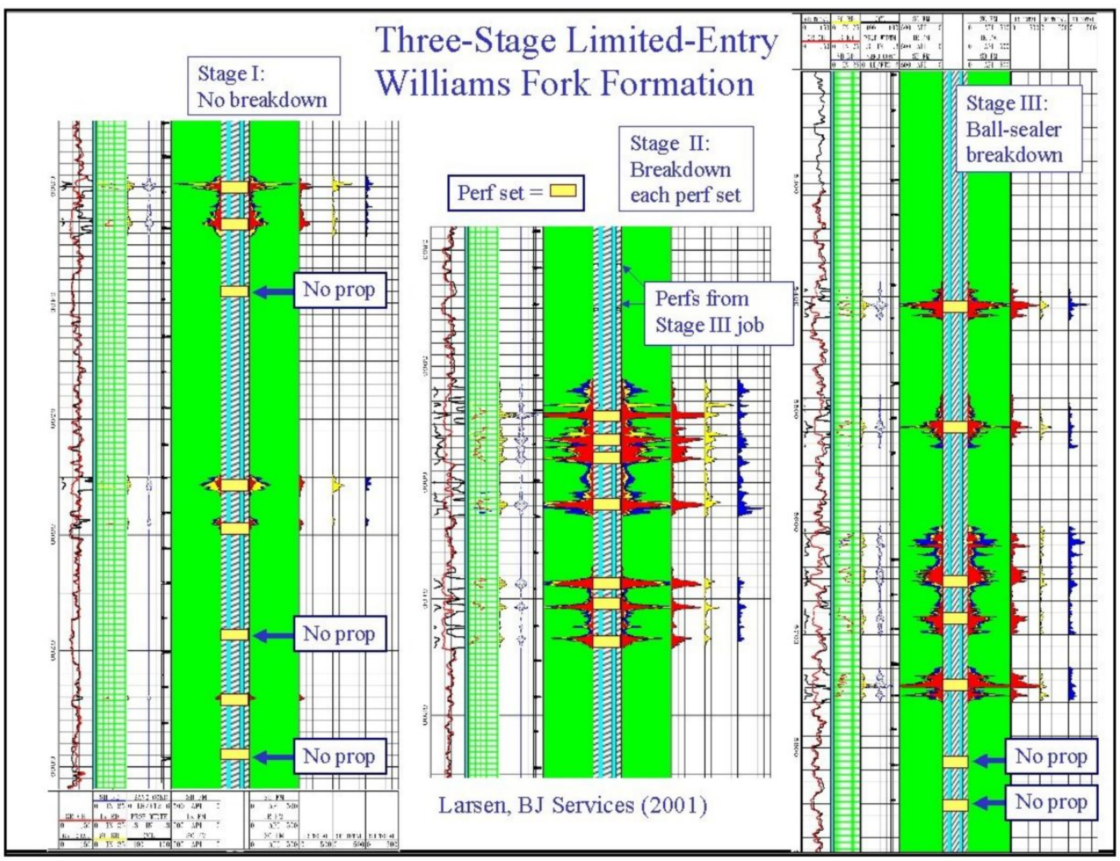


Figure 4: Radioactive Tracer Survey of Limited Entry Treatments Comparing Various Breakdown Methods (from ref. 23)

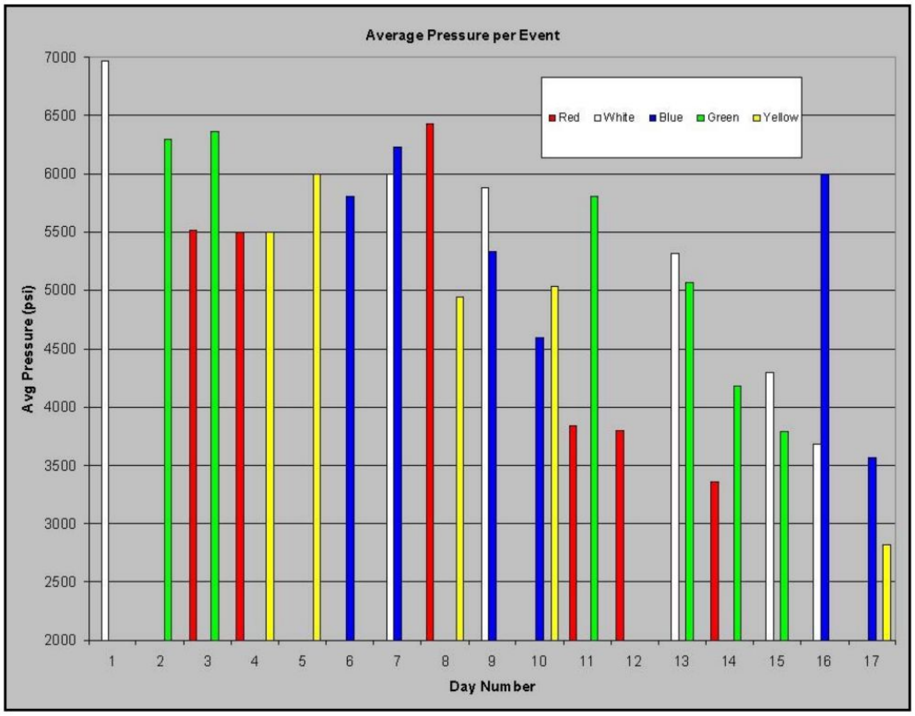


Figure 5: Summary of Surface Treating Pressures in JITP Project (from reference 29)
(Color Code Differentiates the 5 Wells Treated During the Project)

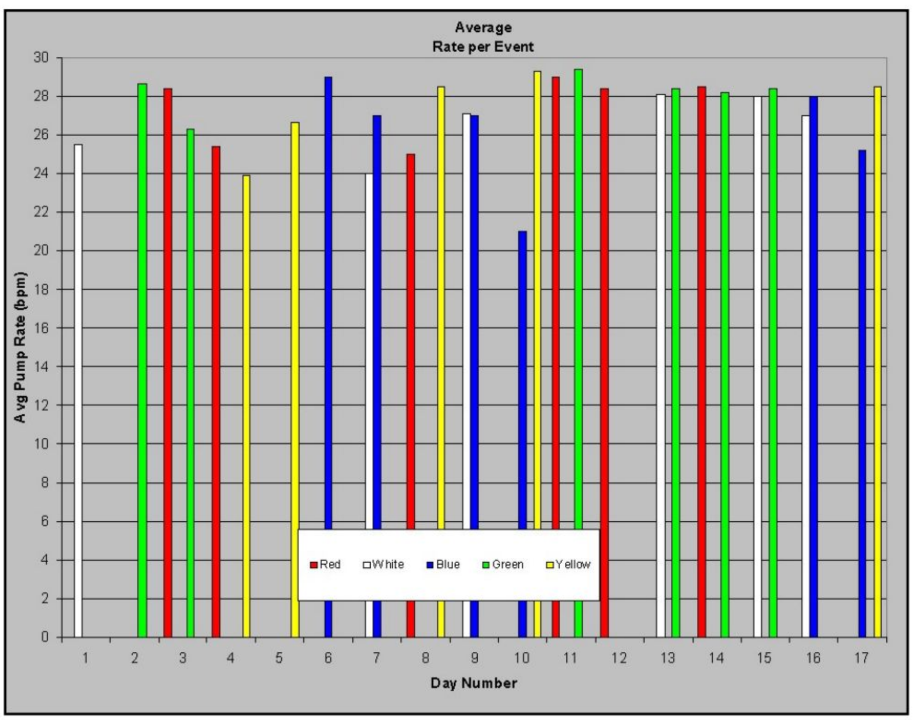


Figure 6: Summary of Treatment Injection Rate in JITP Project (from reference 29)
(Color Code Differentiates the 5 Wells Treated During the Project)

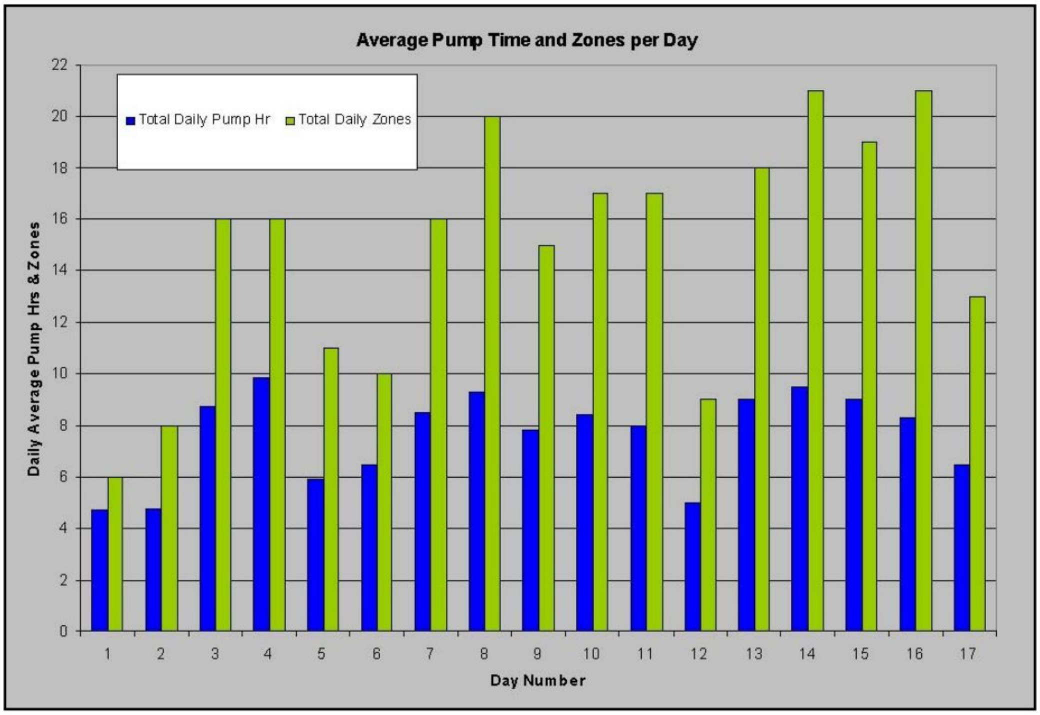


Figure 7: Summary of Daily Activity in JITP Project (from reference 29)

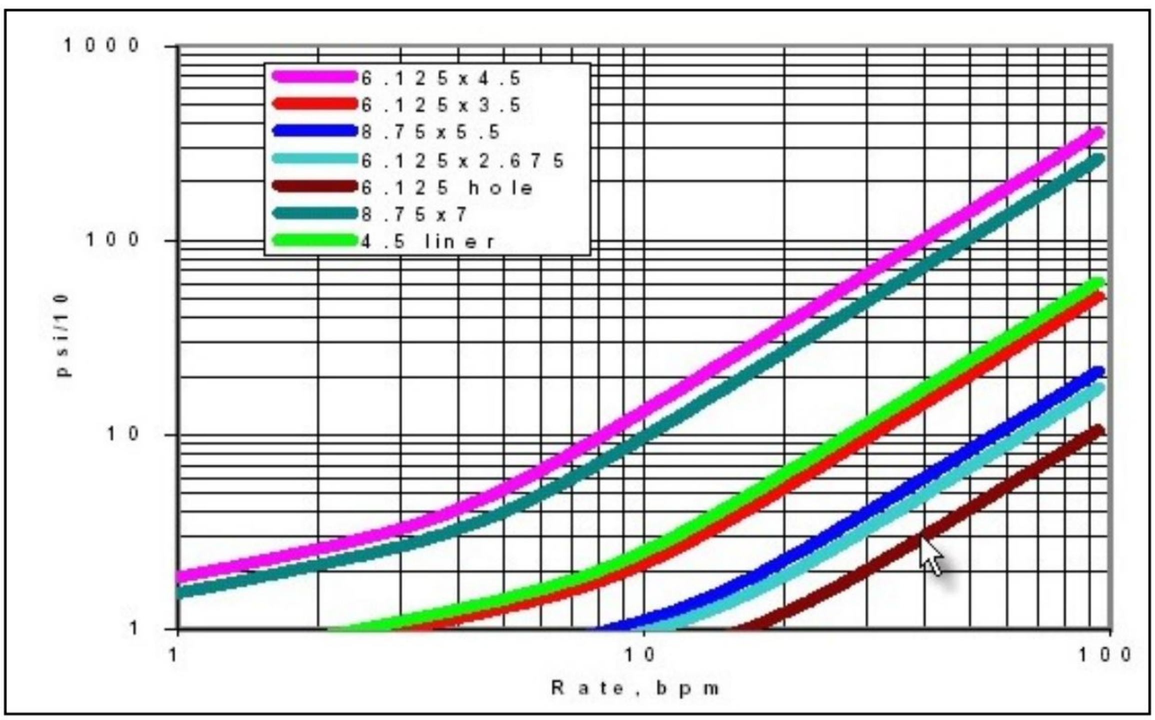


Figure 8: Friction Pressure Graph for Various Annular Flow Configurations (from reference 36)

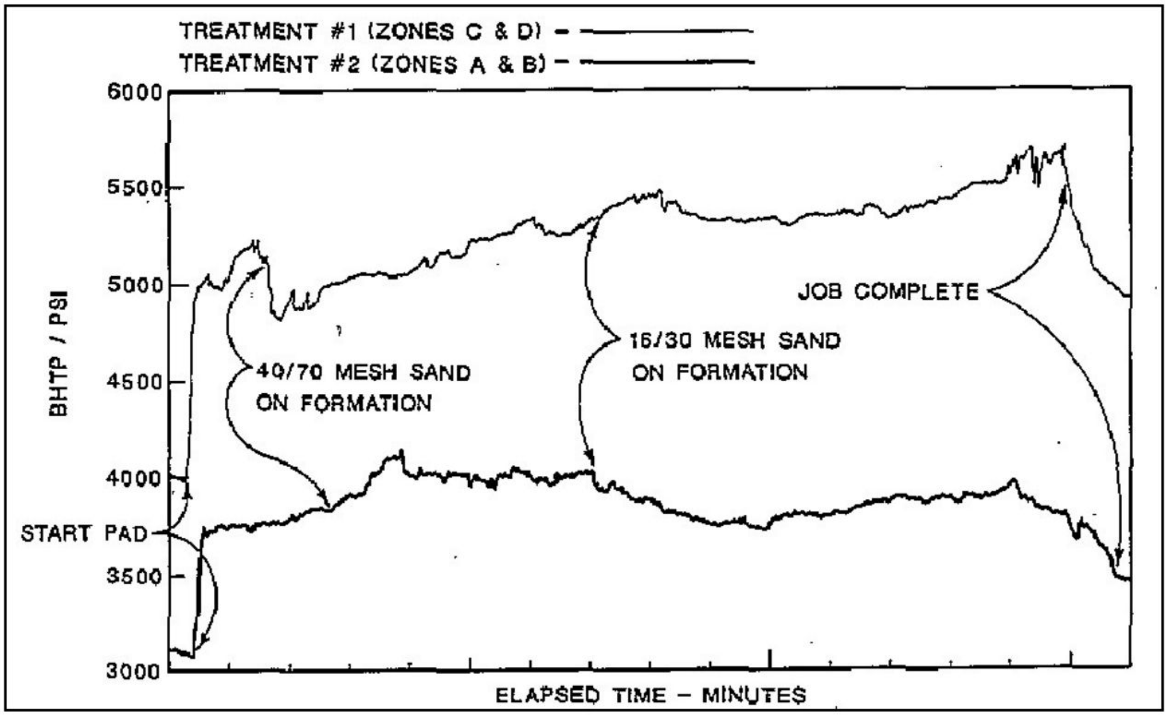


Figure 9: Calculated Bottomhole Treating Pressures for Two Different Coal Seam Groups in the Same Wellbore (from reference 54)