



## *Recent Advances in Hydraulic Fracturing for Enhanced Well Productivity: State of the Art Report*

Ali Daneshy

Daneshy Consultants Int'l, alidaneshy@daneshy.com

Received: 25 Jan 2019; Accepted: 11 May 2019

DOI: 10.22107/JPG.2019.88408

---

### **Keywords**

**Hydraulic Fracturing  
Enhanced Well  
Horizontal Wells  
Production  
Unconventional Reservoirs**

### **Abstract**

Hydraulic fracturing of horizontal wells is considered as the main reason for the phenomenal increase in production of oil and gas from marginal and unconventional reservoirs in North America. The process evolution started more than a decade ago and has resulted in ultra-low permeability reservoirs producing at close to the same rates as some of the very prolific reservoirs in the Middle East, North Sea, and elsewhere.

Major changes in the technology include the following;

1. Creation of numerous (often more than 100) fractures in a single horizontal well, using tens of thousand cubic meters of fluid mixed with tens of thousand tons of proppant.
2. Development of new completion systems that allow successful execution of these treatments at reasonable times and at affordable costs.
3. Development of new tools that are required for successful utilization of the new completion systems. Examples of these include new developments in coil tubing, wellbore isolation, downhole tools, and the technologies that are required for their use.
4. Changes in fracturing fluid types and mixtures to keep costs within affordable limits while also satisfying some of the social concerns of the general public that have resulted from extensive use of hydraulic fracturing.
5. New fracturing monitoring systems that allow optimum application of hydraulic fracturing for increased well productivity. These have included new tracer technology, microseismic mapping, fiber optic sensors, etc.
6. New management systems that coordinate and integrate operations of multiple contractors each responsible for a different aspect of the operation.

Paper will briefly discuss each of these topics and demonstrates their application with examples with actual data.

---

### **1. Historical Background**

No new technology has had the same impact on the production of oil and gas as the combination of horizontal well drilling and creating numerous hydraulic fractures in it. Although the general outlines of both technologies were developed in Europe and North Sea, their wide-spread use was mostly

thanks to high oil and gas prices in the US. These high prices made it financially feasible to explore the application of the new technologies in unconventional ultra-low permeability (nano-Darcy range) shale reservoirs, most notably in Barnette and Marcellus fields. Within just a few years the resulting high productivity of these wells

created a profitable source for new investments in the US oil and gas industry, which eventually resulted in surplus gas production in US, and substantial price drop. Today, gas prices in US are much lower than in Western Europe and many other industrial economies, and the surplus gas is converted to LNG and exported to Western Europe, China, Japan, and elsewhere.

The first fractures created in horizontal wells used a bull-heading pumping technique. Fluid was pumped into the entire horizontal openhole without any well segmentation. The horizontal wells were usually drilled in naturally fractured formations with the expectation of intersecting and linking the natural fractures to the horizontal well. Fracturing treatments were attempted when the horizontal well, by itself, did not yield satisfactory production result. Fracturing was used as a way of extending the reach of the wellbore into more natural fractures. Some of these wells were completed with a slotted or perforated liner to allow well re-entry at a later time. There was no control on the location or number of created fractures. These types of treatments had a mixed success record.

The first contemporary multi-stage fracturing treatment in a horizontal well (known to this author) was completed in the Devonian Shale (now known as Marcellus) in 1987. It was fractured in eight stages using N<sub>2</sub> and CO<sub>2</sub> foam. The multiple well segments were separated with seven inflatable packers. The completion consisted of sliding sleeve ported collars attached to a 4 ½" (114.3 mm) liner. The first single trip cased and cemented horizontal well propped fracture treatments were performed by Maersk in the Danish Sector of North Sea in 1989, Damgaard et. al

(1992). These used a specially designed and built tool system that allowed completion of each stage of fracturing with a single trip. The completion system was called PSI (Perforate, Stimulate, Isolate).

The first cased and cemented horizontal well fractured with ball-activated sliding sleeve system known to this author was performed in the central North Sea, Thomson and Nazroo (1998). The acid fracturing treatments were successfully performed in up to ten zones. Use of this completion system resulted in faster pumping operations, without the need for any trips.

Successful application of horizontal well drilling and multi-fracturing in unconventional shale reservoirs, starting with Barnett formation, was the motivation for development of multiple innovative completion systems for different operational environments. The focus of these developments has been reduction of the cost and duration of fracturing, creation of more fractures in the expectation of better production, ease of operations, more reliable downhole tools, longer horizontal reach, and system flexibility to respond to operational problems and difficulties.

## 2. Discussion

The first consideration in the selection of a completion system for multi-stage fracturing in a horizontal well is well stability; whether the formation is competent enough to support a long term stable horizontal well or not. If the well is considered stable, then one has the flexibility to select an open or cemented liner completion based on other considerations. If not, a cemented liner is the prudent selection.

## 2.1. Openhole liner completions

Multiple commercial systems are available for fracturing openholes completed with a liner. The following offers a brief description of the more popular systems.

Ball-activated sliding sleeves. The most popular of these systems, and the one most often used at the start of horizontal well fracturing in low permeability and unconventional reservoirs, uses ball-activated sliding sleeves for diverting the injected fluid into its proper target. Figure 1 shows a typical completion assembly.

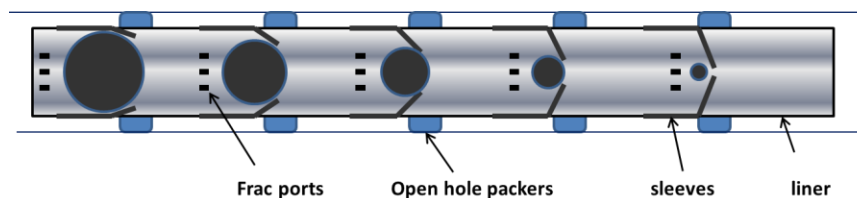


Figure 1. Schematic of a ball-actuated sliding sleeve system

Openhole packers segment and isolate the horizontal openhole into the desired number of stages. Fracturing operations start at the toe of the well and progress towards the heel. At the end of each stage a ball is pumped with the treatment fluid into the well. When the ball reaches its target seat, build-up of fluid pressure in front of it causes sliding of the sleeve and diverts the treatment fluid into the ports opened by the sleeve movement. This process continues multiple times, until all well segments are fractured.

The beneficial features of this type of completion include;

1. Production contribution from the openhole as well as the created fractures. This is particularly beneficial for naturally fractured formations.
2. Continuous fracturing operations. Fluid injection is continuous and different fracture stages are separated by dropping a ball with a specific diameter to open its targeted sleeve. This reduces the duration and cost of fracturing and overall completion costs.
3. Less after-frac operations. The well is ready for production after the flowback of the fracturing fluid and well clean-up operations. This feature of the completion makes it suitable for long reach horizontal wells where the measured depth in some horizontal wells reaches more than six kilometers. It should be stated that in

many shorter reach wells the completion is often milled out immediately after the frac job to fully open the flow path.

4. Lower risk of screen-out. If the pressure in the extending fracture increases to the point of near screen-out, the higher pressure in the openhole section can cause initiation and extension of another fracture. However, it should be stated that screen-outs still do occur in these types of completions.
5. Lower risk of liner blockage by proppant flow back. Returned proppant from the fracture can accumulate and maybe even bridge in the annular space between the liner and openhole. Nevertheless, proppant flowback inside the liner has occasionally been noted in some of these completions.

Drawbacks of this completion system

include;

1. Lack of control on fracture location. While the created fracture is located between the two intended packers, its exact location, and consequently the spacing between the created fractures is somewhat uncertain.
2. Unknown number of fractures. Presence of multitudes of exposed natural fractures in each isolated segment can cause simultaneous creation of more than one fracture, especially for long isolated intervals. Division of the injected fluid into multiple fractures causes them to be shorter and less conductive than it would have been with a single fracture.
3. Uncertain initiated fracture type. The type and orientation of the initiated fracture is likely to be influenced by the size and orientation of natural fractures exposed to fluid pressure. However, the initiated fracture will soon re-orient itself and extend perpendicular to the prevailing minimum principal stress. In general, the wellbore geometry creates a more favorable environment for initial extension of axial/longitudinal natural fractures.
4. Risk of isolation deficiency. Efficiency of openhole packers in isolating the adjacent intervals depends on well condition.

Irregular well shape and non-circularity can interfere with packer seating and isolation between stages. This can be particularly troublesome in cases where the horizontal well should not have been completed openhole. Another factor causing lack of isolation is initiation or extension of a longitudinal/axial fracture close to the packers. Extension of this fracture to the other side of the packer can reduce the number of created fractures and leave some well intervals without a fracture.

5. Re-fracturing. Potential complications that could arise in re-fracturing these wells include inability to isolate a specific interval, uncertainty about where to place the new fractures, and where the actual created fracture is located. Nevertheless, some wells completed with this system have been successfully re-fractured in the past.
6. Operational difficulty in case of a screen-out. One can encounter operational difficulty in cleaning the well after a screen-out in order to resume the fracturing operations, especially if the screen-out occurs close to the toe of the well.

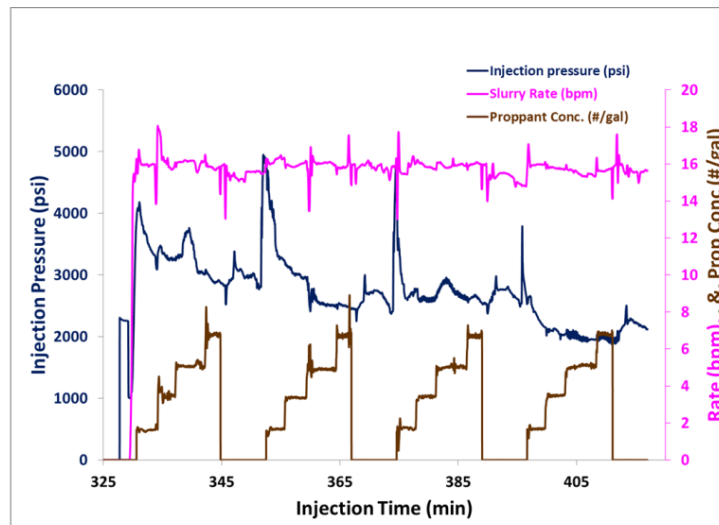


Figure 2. Example frac chart for a ball-actuated completion

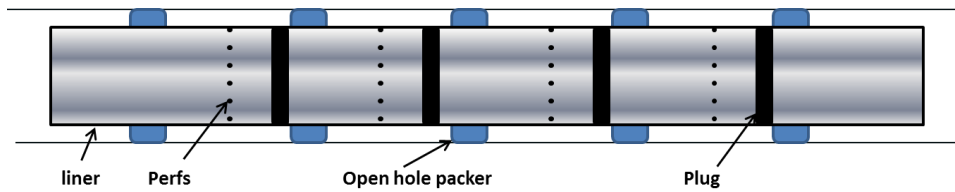
Figure 2 shows part of an example treatment performed with the above system. The graph shows treatment data for 4 stages of a fracturing treatment which were injected during a 97 minute continuous injection. The spikes in the pressure data are created by the water hammering effect of balls getting trapped in their designated seats, closing the previous flow path and sliding the sleeve that opens the ports for the next fracture stage.

Over the years there have been a number of advancements in this system. These include;

1. Increase in the number of stages. Initially the number of stages was limited by the liner I. D. and ball size increments (1/4", 6.3 mm). Newer systems work with smaller ball size increments (1/8", 3.6 mm).
2. Another method for increasing the number of stages has been opening multiple sleeves with each ball drop. These systems use limited entry to design the port openings to allow proper fluid distribution among the different stages fractured simultaneously.

3. Dissolvable balls. In field practice, sometimes all of the injected balls do not flow back to the surface during the clean-up. Dissolvable balls were developed in response to this concern. They dissolve in the wellbore fluid.

Plug & Perf system. The openhole segment of the horizontal well is divided into the desired number of segments, using openhole packers mounted on a liner. Each well segment is fractured by placing a plug downstream of its intended segment. The target interval is then perforated and fractured, Fig. 3. This sequence is repeated again by placing another plug upstream of the zone just fractured but downstream of the next target, perforating the intended segment, and fracturing it. The combined operations of setting a plug, perforating and fracturing continues until all well segments are fractured. At the end of all treatments the plugs are milled out, the well is cleaned and put on production.



**Figure 3. Schematic of plug & Perf completion in openholes**

Some of the positive features and drawbacks of this completion are similar to ball-activated sliding sleeves. An additional benefit is fullbore access during production and future possible intervention. This also allows using higher rates for the fracturing treatments. On the other hand, these treatments take longer because of the time needed for setting the plugs and perforating. Milling the plugs at the end of all stages also adds to total fracturing time and cost.

Hybrid system. This consists of the combination of ball-activated sliding sleeves and Plug & Perf. It is sometimes used for fracturing very long reach horizontal wells. The ball-activated sleeves are placed at the toe, with Plug & Perf close to the heel of the well. This combination reduces the need to mill the plugs too far from the surface.

Dual injection systems with hydra-jet perforating. These systems usually use coil tubing (CT) for either perforating the well, and/or for injecting the fracturing fluid. They are used for both open and cemented liner completions. The common practice while using these systems is to pump the fracturing slurry through one conduit (CT or annulus), while maintaining a low injection rate through the other (usually referred to as the “dead” string). However, both strings are always available for pumping and can be used to address special situations.

Some of the important beneficial features of these systems include;

1. More certain fracture location. One of the concerns with fracturing open holes is the uncertainty of fracture location, as discussed earlier. The larger diameter of perforations created by this method increases the probability of fracture initiation at the perforations.
2. Robust fracture initiation and extension. The larger size of the perforations create a favorable condition for simpler fracture initiation and extension.
3. Simpler installation. Since these systems do not require a liner or open-hole packers, they are easier to install.
4. Versatility. One can easily, and almost instantly, change and manipulate the fluid mixture injected into the fracture, without having to wait until the surface changes are displaced to the perforation depth.
5. Flexibility. The ability to circulate the fluid in the well and cleaning it is valuable in case of operational problems, even screen-outs.
6. Bottom-hole pressure read-out. The low injection rate through the dead string generates very low friction pressure. Thus, adding the hydrostatic pressure of the dead string to the value measured at

the surface provides a very good indication of the fracturing pressure at the perforations.

The limitations of the dual injection systems include;

1. Lower injection rates. The reduced pumping conduit area limits the maximum injection rates that can be obtained with these systems. However, the achievable rates are usually sufficient for single fractures.
2. Depth limitation. The depth limitation results from availability of long CT strings, and their pressure limitations.
3. Higher tendency for proppant flowback. The simpler fracture path also

makes it easier for proppant to flowback after the treatment.

Figure 4 shows the well schematic for perforating and fracturing in dual injection completions. The high velocity of fluid stream exiting the nozzles creates a pressure differential between the wellbore and the fracture that prevents fluid from moving within the annulus. This creates a hydraulic isolation system that removes the need for mechanical isolation within the wellbore (such as open-hole packers). Two different fracturing systems are available for this set-up; injecting through the annulus, or injecting through the CT.

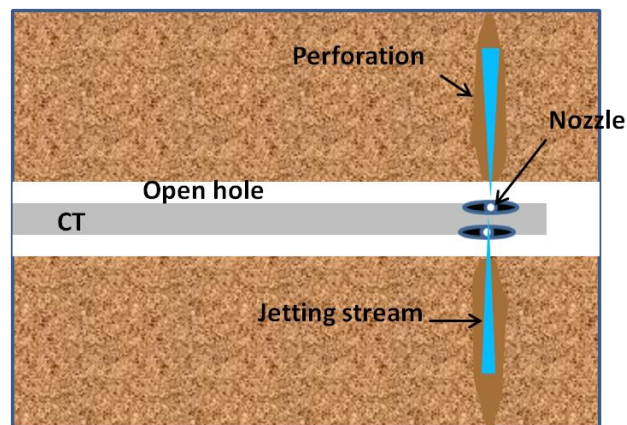


Figure 4. Schematic of hydra-jet perforating and fracturing system

CT-operated sliding sleeve systems. Functionally, these systems are very similar to the ball-activated systems, with the exception that the sleeves are opened mechanically, using a tongue and CT. There are multiple versions of this system in commercial use. In one version, after the sliding sleeve is opened, the CT is pulled up during fracturing and pumping is done through the fullbore liner. This allows for higher injection rates. At the end of each

stage the sleeve is closed using the same CT, the next sleeve is opened, CT is pulled uphole, and fracturing operations are continued. The main advantage of these systems is presence of CT that can be used to clean the well after each treatment, and even in case of a screen-out. The other advantage is having fullbore access. Occurrence of screen-out can also cause an operational problem if the wellbore sand prevents closing of the open sleeve.

At the end of all fracture stages, all the closed sleeves are opened and the well is cleaned out in preparation for production.

In another version, the well is isolated by a retrievable plug located at the end of the CT and set inside the liner, Figure 5. In these systems the ports stay open in the previous fractured intervals. Isolation between the new and previous frac stages within the liner is secured by setting the retrievable plug

between the new and the last fractured ports. At the end of each stage the plug is released and set in its new position just below the next ports and fluid injection is resumed through the annulus. Injecting at very low rates through the CT ensures that it is open and available in case of need for fluid circulation to clean the well. Surface CT pressure provides a reasonably accurate indication of the real-time bottomhole frac pressure.

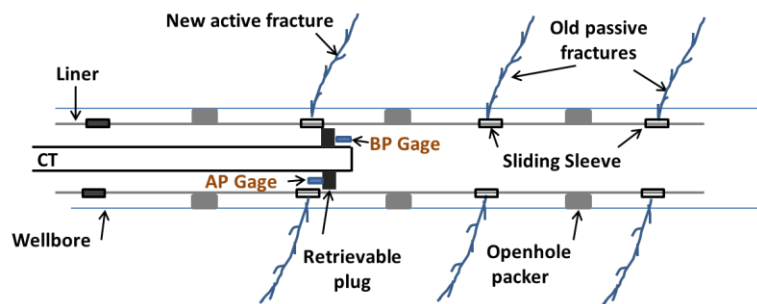


Figure 5. Schematic of CT-operated sliding sleeve system

One of the very useful features of these systems is the ability to record pressure and temperature above and below the retrievable plug, using two memory gages, Figure 5. The BP (Below Plug) memory gage records the shut-in pressure and temperature of the commingled fluid in the previous fractures. The AP (Above Plug) memory gage records the pressure and temperature of the fluid while fracturing. The data recorded with these gages is retrieved after the CT is pulled out of the well. Analysis of this data allows us to not only evaluate the fracture growth pattern, but also the integrity of isolation between stages.

**Cemented liner completions.** The mechanical components of many of these systems are very close to the corresponding models used for openhole systems, with a few minor changes. Below, features of these

systems are reviewed briefly.

Ball-activated sliding sleeves. In principle, there is little difference between these systems and the corresponding units used in openholes. The main difference is that the liner is cemented in the horizontal well. Each sleeve is activated by dropping a properly sized ball inside the liner at the end of each fracturing stage. Once the ball is captured by its target seat, the increase in pressure activates and slides the attached sleeve, which then exposes the ports covered by it. Similar to the openhole case, pumping is continuous and punctuated by dropping the balls at the end of each stage. Some of the differences between the openhole and cemented liner systems include;

1. There is no production contribution from the openhole itself.
2. Fracture initiation is not as robust.



3. Screen-out is more likely in cemented liner compared to openhole application.
4. Fracture location is more accurately known.
5. There is less chance of creation of multiple fractures during each injection cycle.

Plug & Perf systems. At the present time this is one of the more popular systems for fracturing horizontal wells. The main difference between the openhole and cemented liner completion is in the number of fractures that can be created with them. Cemented liner systems allow creation of multiple fractures during each pumping stage, as shown in Figure 6. The well is divided into multiple segments, with each segment perforated in multiple clusters equal to the desired number of fractures in that segment. Appropriate distribution of the injected slurry within the created fractures is secured using the limited entry perforation technique. In this technique the intent is to cause equal fluid distribution between the created fractures by limiting the number of perforations such that flow through each perforation creates a friction pressure between 200 to over 1000 psi (~1.4 – 6.9 MPa), depending on the fracturing strategy. Perforations are created in separate clusters, each cluster supplying fluid to a separate fracture. Lower perforation friction (200 – 400 psi, 1.4 – 2.8 MPa) requires more perforations and results in lower surface fracturing pressure. High perforation friction

requires fewer perforations and will result in higher surface fracturing pressure. The number of fractures created during each pumping cycle depends on the desired injection rate in each fracture. In initial limited entry designs, 3 – 6 fractures were created in each stage with 200 – 400 psi (~1.4 – 2.8 MPa) perforation friction. In some of the more recent applications the number of created fractures is larger, 7 – 10, with fewer perforations for each fracture and higher perforation friction. The spacing between clusters (and therefore the individual fractures) has been reducing over the years, starting with several hundred feet (close to 100 meters) and gradually reduced to less than 10 meters at the present time. At the end of each pumping cycle, the well is shut-in, the next plug and perforation assembly is pumped to its target location, the plug is set, the next clusters are perforated, and the perforation assembly is pulled out. In the more popular of these systems a ball is initially dropped through the vertical section of the well and then pumped in the horizontal section until it seats in the plug and isolates the previous well segment. Injecting frac slurry causes creation of multiple fractures from the clustered perforations. This process is repeated multiple times until all the desired segments are fractured. In some recent applications, more than 200 fractures are created in a single horizontal well that extends more than 3 kilometers horizontally within the formation.

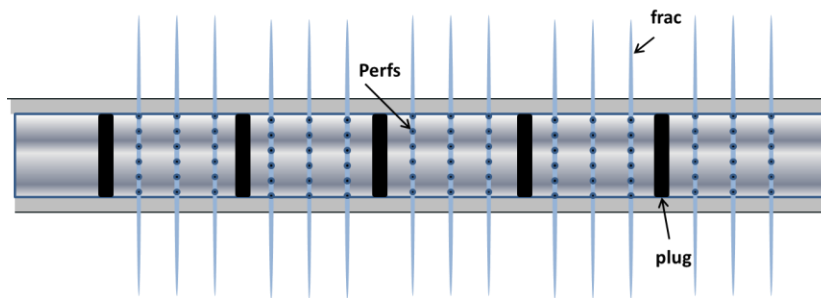


Figure 6. Schematic of Plug & Perf completion in a cemented liner

Some of the critical features of Plug & Perf completions include;

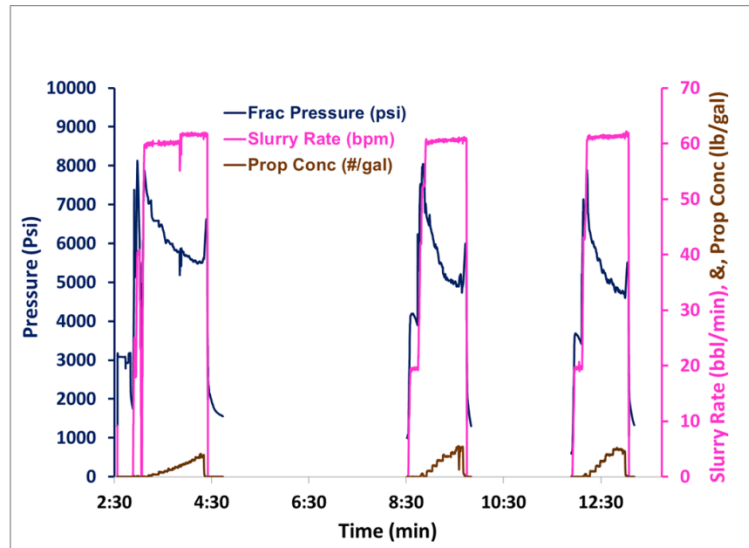
1. Operational efficiency. Creation of multiple simultaneous fractures has significant operational appeal by reducing time, and therefore cost of fracturing operations.
2. Larger number of fractures. These systems allow creation of more than one hundred fractures in a single horizontal well.
3. The actually created number of fractures can be less than the number of perforated clusters. The controlling variable is the rate per perforation; the higher this rate, the higher the chance of fracturing in every cluster. Typical rates for a 0.4" perforation (10 mm) range 1.5 – 6 bpm/perf (~0.25 – 1 m<sup>3</sup>/perf). The higher rates also require higher injection pressure, but with a lower risk of missing an entire cluster.
4. More complete coverage of the formation with created fractures. Larger numbers of fractures allow shorter spacing between them. This results in more thorough coverage of the formation with the created fractures.
5. Reduction of production risk. Creation of multitudes of fractures reduces the production risk associated with a few non-
6. Higher fracture resilience. Creation of multiple simultaneous fractures reduces the likelihood of total screen-out because even if fluid cannot be injected into one or two of the induced fractures, the remaining fractures can absorb the injected fluid, though at a higher pressure, and/or a lower rate.
7. Higher chances of interactions between created fractures, especially when the spacing between clusters is short. Multiple manifestations of the interactions include;
  - a. Higher fracturing pressure. During each pumping cycle, each fracture has to overcome the influence of a neighboring actively growing fracture. This effect, called DAFI (Dynamic Active Fracture Interaction), creates a higher resistance to fracture growth than the initial minimum in-situ principal stress, Daneshy (2015). Furthermore, differences in the size and shape of the created perforations cause unequal fluid distribution between the fractures, which results in unequal fracture sizes (width and length). Thus, the shorter fractures that are receiving less fluid volume have to grow in the shadow of longer

fractures. This further exacerbates the inequality in fluid distribution between the fractures created at the same time. Another manifestation of DAFI is change in the orientation of the principal stresses that each fracture is exposed to. The change in principal stress orientation causes the created fractures not to be parallel with each other. In cases of short spacing between created fractures, this can cause coalescence of shorter fractures with longer adjacent fractures. Once this happens, the shorter fractures become fluid sources for the extension of longer and more dominant fractures. The net effect is creation of fewer effective fractures that extend long distances into the formation. This pattern of fracture growth provides partial explanation for the unusually long fractures observed with this type of completion, and why some of these fractures often intersect fractures in adjacent wells, sometimes more than 1000m away. Growth of these long fractures is coming at the expense of much shorter inside fractures.

- b. Natural fracture activation and suppression. Stresses induced by high fracturing fluid pressure may cause opening and activation, or sometimes closure of natural fractures that may exist in the formation between them. Best

chance of natural fracture activation is at the time it is intersected by the hydraulic fracture, Daneshy (2016), Nagel et. al (2013). Once the hydraulic fracture extends beyond a natural fracture, the high fluid pressure inside it induces formation stresses that can cause closing or narrowing of some of the existing natural fractures. At the same time, stresses induced at the tip of each fracture can cause tensile activation of natural fractures close to the tip. This activation is more prominent near the tip of the longer fractures since they are outside the influence zone of shorter adjacent fractures.

- c. Higher Instantaneous Shut-In Pressure (ISIP). Increase in the magnitude of the principal stresses altered by the presence of adjacent fractures causes an increase in ISIP.
8. Narrower fracture widths. The opening of the created fractures is not controlled by laws of fracture mechanics formulated for single fractures. This results in narrower and consequently longer fractures. Reducing spacing between fractures causes narrowing of their widths, Daneshy (2015).
9. Extension of the longer fracture can cause tensile activation of natural fractures located close to its tip, Daneshy (2016). Chance of this type of activation is higher for natural fractures that are located closer to the created hydraulic fracture.



**Figure 7. Example treatment chart for a Plug & Perf completion**

Figure 7 shows a typical treatment chart for 3 successive pumping stages with a Plug & Perf completion. The short low rate pumping period at the beginning of each stage corresponds to pumping the ball. Once the ball is seated in the plug, then injection rate is increased. Note that before seating of the balls, fluid injection causes extension of the fractures in the previous stage. Seating of the ball in the plug usually creates a water hammering effect similar to, but less intensive, than ball seating in the sliding sleeve systems. The time lapse between the pumping stages in Figure 7 is used for setting up the next stage; pumping and setting the plug, perforating, and dropping the ball. The difference between injection pressures is quite common in this type of completion. The horizontal well in this example was fractured in 24 stages, each consisting of four perforation clusters. The fluid type was a cross-linked gel. The total fluid volume was more than 3.5 million gallons (~13,250 m<sup>3</sup>) and total proppant was nearly 6.5 million pounds (~2,940 tons). Fluid volumes injected

in each stage varied between 38,000 (~144 m<sup>3</sup>) to 234,000 gallons (~886 m<sup>3</sup>). Max proppant pumped during a stage was 326,500 lbs (~148 tons). As this data shows, much larger fluid volumes and proppant weights are usually pumped in this type of completion. There are also larger variations in treatment details between stages.

Use of slick water (water plus a friction reducer) is quite popular in this completion system. Its benefits are ability to use higher injection rate and fluid volume, as well as reduced total treatment cost.

Dual injection systems. The mechanical systems are very close to those used in openhole liner completions. There are several variations of these systems commercially available. Figure 8 shows an example treatment for systems using CT injection for both perforating and fracturing, with no isolation plugs. Slurry injection up to point A was for perforating the well, after which the main treatment was pumped. The graph shows very stable annulus pressure (dead

string), while the CT pressure is continuously increasing as the CT friction pressure increases due to higher proppant concentrations. Availability of the dead string

pressure is very valuable for decision making during job execution.

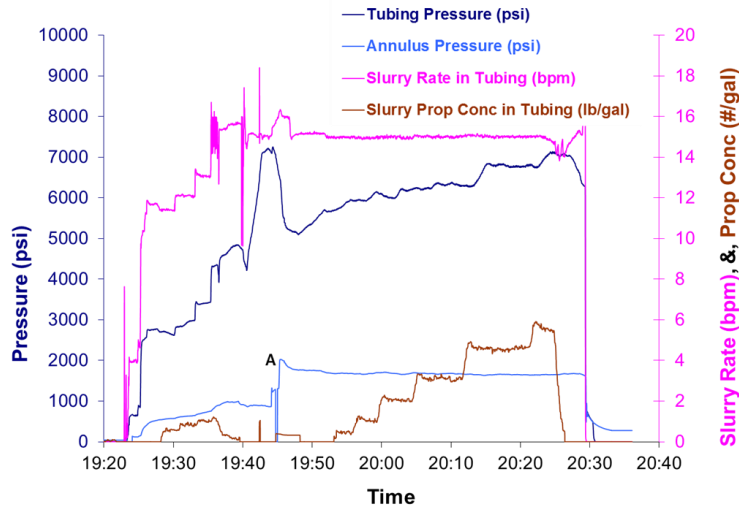


Figure 8. Example case history for a dual injection system & through CT fracturing

Another commercially available dual injection completion system uses a CT with a retrievable plug to isolate between the new and old fracture stages. System schematic is presented in Figure 9. Perforations are created by injecting an abrasive fluid through the CT. Fluid rate during perforation operations is around 1 bpm (~ 0.16 m<sup>3</sup>/min) for each nozzle. Fluid composition is usually water plus a friction reducer, and small sand concentration, usually around 1.0 #/gal (~120kg/m<sup>3</sup>) to increase fluid erosion. Fracturing treatment is pumped through the annulus. Figure 10 shows an example case

history for this system for three successive frac stages. The perforation and fracturing periods are marked for the middle stage. These types of treatments usually take more time than ball-activated sliding sleeves, but less than Plug & Perf. Availability of CT pressure (representing bottomhole treatment pressure) is valuable for real-time decision making during these treatments. Furthermore, adding bottom-hole memory gages, as discussed earlier and shown in Figure 5, provides the data needed for analysis of completion integrity and review of fracture propagation mode.

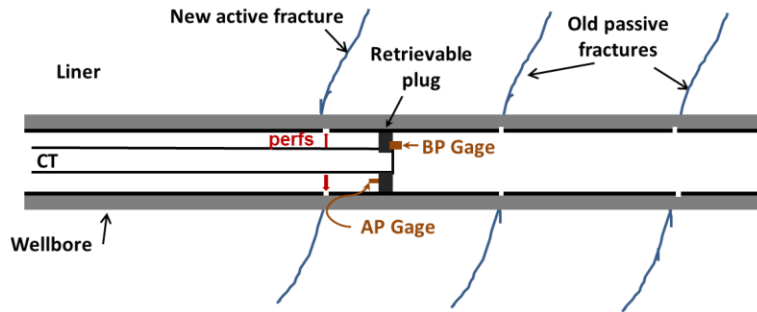


Figure 9. Schematic of CT-operated hydra-jet perforating with retrievable plug solution

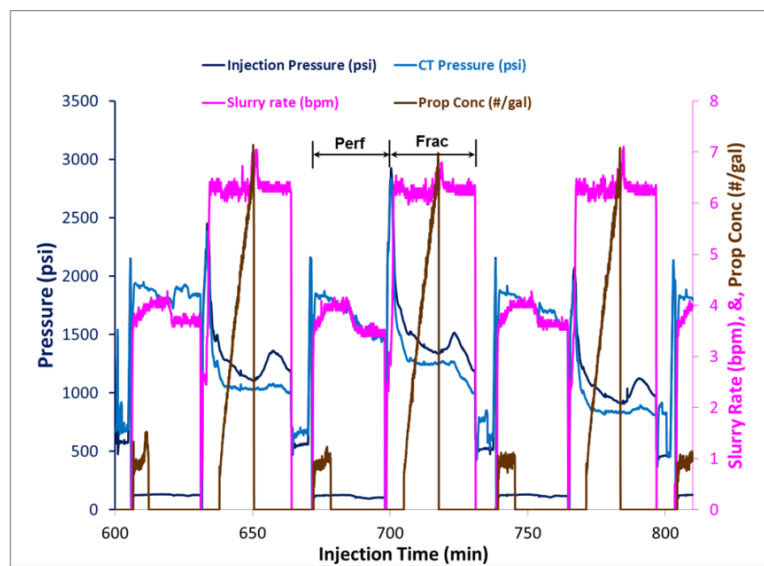
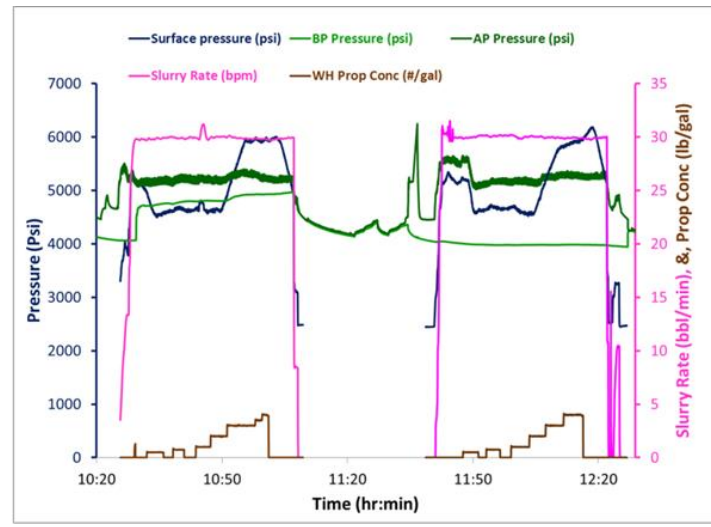


Figure 10. Example case history for dual injection system using a retrievable isolation plug & injection through annulus

CT-operated sliding sleeve systems. The completion system is very similar to that used in openholes and presented earlier in Fig. 5, except that the liner is cemented in the well. With this completion only a single stage is fractured during each injection cycle. At the end of each frac stage the retrievable plug is released, moved uphole and set in its new position. The target sleeve is opened with the CT, and fluid injection is resumed. Figure 11 shows the treatment data for a typical such

completion. In addition to the standard data, this figure also includes the pressure data recorded with the AP and BP memory gages (shown in Figure 9). Review of the data in this particular case shows lack of isolation in the first frac stage, and proper isolation in the second stage. Access to this data and knowledge of well condition is very valuable for planning future fracturing operations and deciding action items for improving the results.



**Figure 11. Example treatment data for CT operated sliding sleeve completion & BH memory gages**

Figure 11 also shows the typical time lapse between successive frac stages with this completion.

CT-operated re-closable sliding sleeve systems. The difference between this and the system presented above is that at the end of each pumping stage the active fracture sleeve is closed before the downhole assembly is moved up to its next target. The retrievable plug is set and the next sliding sleeve is opened for the next frac stage. The closed sleeves are opened at the end of fracturing all stages.

This system also offers the option of adding bottomhole gages for recording pressure above and below the packer.

The most significant feature of this completion is its ease of re-fracturing. This can be done by re-closing all the sleeves except the target of re-frac job. After this zone has been fractured, its sleeve is closed and the next intended sleeve is opened. This process continues until all targeted zones have been re-fractured.

Other features of this system include;

1. Ability to control flow mix, for example if the well is producing excessive water. This can be done by closing the sleeves at those zones that are producing excessive water.
2. Random fracturing sequence. The sleeves can be opened in any desired sequence for fracturing the corresponding stage.
3. Proppant flowback control. Since each sleeve is closed at the end of its frac treatment, the proppant stays in the zone until all zones have been fractured. The added time for breaking of the fluid and settlement of the proppant will result in less proppant flowback.

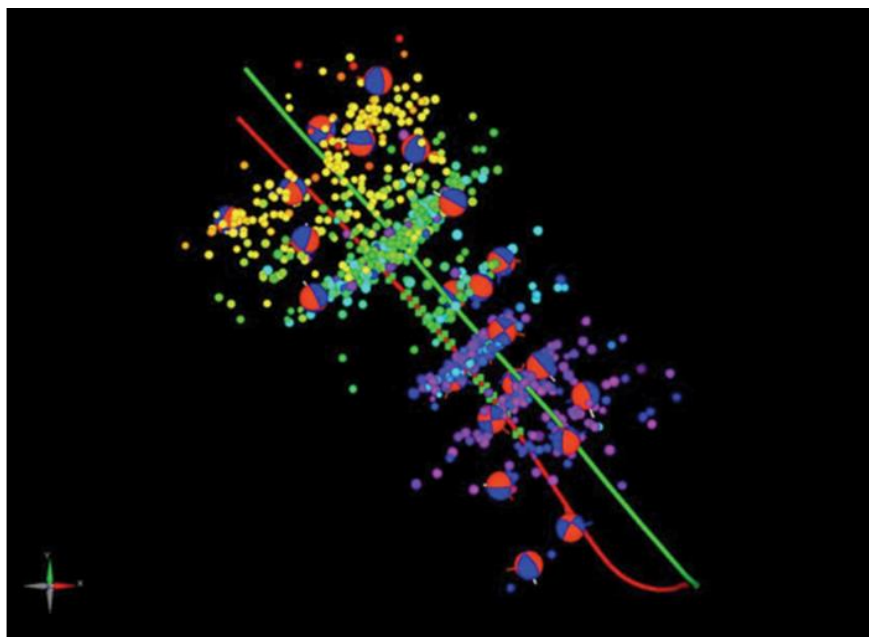
Re-closable sliding sleeve systems are relatively new and do not have long term historical data to show their long-term reliability and performance.

### 3. Fracture Diagnostics

The high cost of horizontal well drilling and fracturing requires reliable diagnostic tools to determine the outcome of these operations. As a starting point, in order to optimize the

well production, one needs to know the orientation of the hydraulic fracture before drilling the horizontal well. The most productive hydraulic fractures are those that extend perpendicular to the horizontal well, commonly called transverse fractures. Since the azimuth of the created fractures is controlled by the orientation of the minimum principal stress in the formation, effective use of the technology requires advanced knowledge of fracture orientation so that the horizontal well can be drilled perpendicular to this orientation. The common industry practice for determination of fracture orientation is to drill the first horizontal well (pilot well) based on existing knowledge of the local structural geology of the formation.

More accurate fracture orientation is then determined while creating the fractures in the pilot well using the microseismic fracture mapping technique. In this technique the compressional and shear waves generated by breaking/fracturing of the formation are detected by very sensitive instruments placed in a nearby well or at the surface. The location of each fracture event is then detected from the difference in the arrival times of the created compressional and shear waves and knowledge of their velocities in the formation, very similar to how earthquake locations are determined. Once the fracture orientation is determined in the pilot well, the information is used for drilling future wells in the proper direction in the same field.



**Figure 12. Microseismic map of a horizontal well fractures**

Figure 12 shows an example of the microseismic mapping of several hydraulic fractures created in a horizontal well.

Another popular fracture diagnostic technique is radioactive tracer logging. In this

system a very small volume of radioactive beads that have the same size as proppants are mixed with it and injected inside the fracture. The three popular types of tracers are Scandium 46, Iridium 192 and Antimony



124. A different type of tracer is pumped in each fracture stage. Logging of the well after the fracturing treatments shows the location of the tracer near the wellbore and allows determination of efficiency of fracturing

operations. Figure 13 shows the tracer log after an example treatment. It shows absence of fractures in several well segments causing ineffective well stimulation.

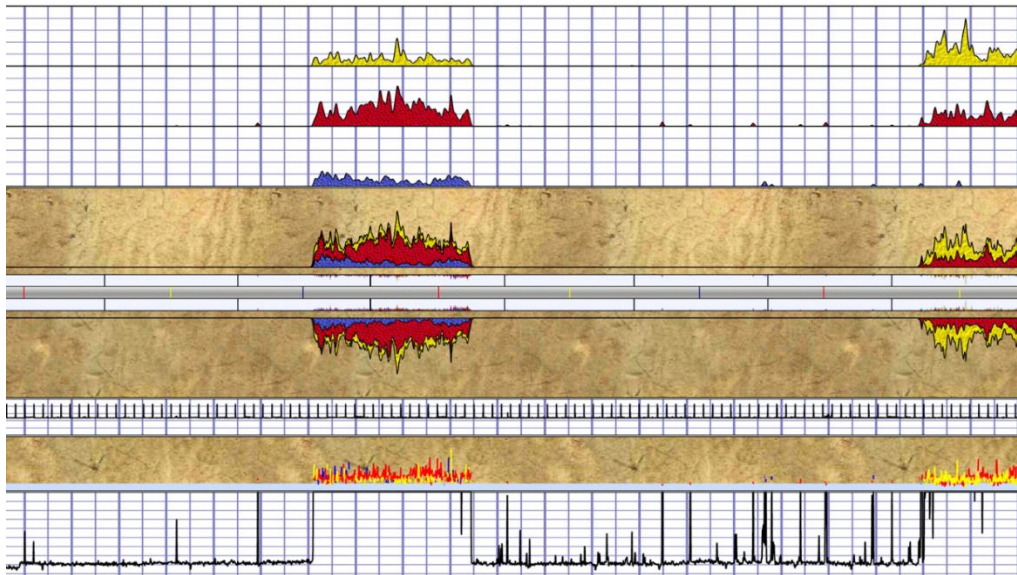


Figure 13. Example radioactive tracer log in a horizontal well

Liquid tracer logs. These water-soluble tracers are mixed with the fracturing fluid and injected with it. A different type of tracer is injected during each fracture stage. Returned fracturing fluid is sampled and chemically analyzed in the lab to determine presence and concentration of each tracer in the returned fluid. Analysis of this data helps determine how quickly the fracturing fluid used in each stage is returned to the surface.

#### 4. General Fracturing Trends

Over the years horizontal well fracturing has undergone substantial evolution. The general trends of some of these changes are summarized below.

Completion Type. Open hole liner completions with ball-activated sliding

sleeves were the initial favorites of the industry after the economic viability of multi-fractured horizontal well system was established for the unconventional reservoirs in North America. The attractive features of these systems included faster completion and fracturing operations, together with the belief that the openhole accommodated taking advantage of flow through the existing natural fractures in these reservoirs. But when borehole stability was in question, cemented liner was the only viable option. Initially, these completions were also fractured using ball-activated sliding sleeves.

Once the economic viability of multi-fractured horizontal well completion was established by the industry, attention was focused on drilling longer reach horizontal

sections, which then also necessitated the need to increase the number of fractures. This brought attention to one of the limitations of the initial ball-activated sliding sleeves. Since these systems used incrementally larger size balls for successive stages of fracturing, they could accommodate only a limited number of fractures, depending on the size of liner and increments in ball diameter. The need to increase the number of fractures created in long reach horizontal wells promoted use of Plug & Perf systems that offered the possibility of creating more fractures with shorter spacing between them, using multiple perforation clusters together with limited entry fracture design. Another development that promoted use of Plug & Perf completion systems was use of "slick-water" fracturing fluid. Slick-water, which consists of water as the base fluid mixed with a friction reducer to allow injection at higher rates, had already been in occasional use for high rate fracturing treatments in vertical wells. Its benefits included lower cost, ability to inject at higher rates, and simpler fracturing operations. These features were quite attractive for creating tens of hydraulic fractures in long horizontal wells (several thousand feet long), and requiring reasonable pumping time and cost. Gradually, and through multiple statistical analyses of production results, use of slick water has been established as another viable fluid to complement the standard gelled and cross-linked polymer mixtures which were the favorites for fracturing vertical wells. The general trend of today's fracturing treatments is;

1. Larger number of fractures. Creating more than 100 fractures in a single horizontal well is quite common. In some cases more than 200 fractures have been created in a single well, with horizontal extension of

more than 3 km. The main motivating factor for increasing the number of fractures is the expectation that more fractures yield higher production.

2. Gradually reduced spacing. Initial fractures in horizontal wells were usually spaced nearly 200m apart. Plug & Perf completions facilitated reducing this spacing to a few tens of meters. In some rare instances, these fractures are initiated just a few meters apart.
3. Larger proppant volumes. The general trend of the industry has been towards increased volumes of proppant. Use of several million pounds (a few thousand tons) of proppant (sand) in a single horizontal well is quite common these days. With the reduced cost of fracturing operations, some of these treatments are known to have used more than several hundred thousand tons of sand.
4. Smaller size proppant. The general industry belief is that fractures in horizontal wells are much narrower than they were in vertical wells. This has led to a wider use of finer size proppants, specially 100 mesh sand.
5. Larger treatment volumes. Injecting several million gallons (several tens of thousand m<sup>3</sup>) of fluid in a single horizontal well is quite common. The treatment volume is generally controlled by the planned weight of sand.
6. Higher use of slick water. Because of its lower cost and lower injection pressure, this fluid is often used in conjunction with large treatment rates and fluid and sand volumes. Creative fluid mixtures include use of slick water as pad or spacer between slurry stages, and cross-linked polymer for carrying the slurry.

7. Alternate fracture designs. These include use of “pillar frac” which consists of using multiple slugs of sand-laden slurry followed by sand-free spacer, use of polymer fibers to cause higher fracturing pressure in the expectation of activating natural fractures, diverter chemicals to more evenly distribute the fracturing fluid within multiple clusters, and more.
8. Use of commonly available water. The social pressure to reduce use of fresh water has resulted in development of multiple chemical systems that allow use of water from commonly available sources, such as sea water, formation water, returned fracture fluid, etc.

### 5. Closing Notes

Proper well design, the length of its horizontal section, wellbore size, and choice of the completion system are very important for productivity and financial viability of a horizontal well. Short term considerations

include planned number of fractures, preferred fracturing fluid and achievable rates, equipment reliability and performance, and cost. But equally important are issues related to long term well life and ability to execute future well operations such as ability to re-enter the well for any required logging or workover services. Remedial operations can include removal of scale or proppant flowback that may restrict production flow. One of the more critical of these operations is re-fracturing. Successful and efficient re-fracturing requires ability to determine which segments of the well need to be re-fractured, and being able to cost effectively execute the plan.

#### Unit Conversions

1.0 MPa = 145.04 psi

1.0 Meter = 3.28 feet = 39.37 inches

1.0 Kilogram = 2.2 pounds

1.0 Cubic meter = 264.17 gallons

### 6. References

- Damgaard, A. D., Bangert, S. D., Murry, D. J., Rubbo, R. P., Stout, G. W. (1992). “A Unique Method for Perforating, Fracturing, and Completing Horizontal Wells”. SPE Production Engineering, Feb. 1992.
- Daneshy, A. A. (2015). “Dynamic Active Fracture Interaction (DAFI) in Horizontal Wells” HFJ, Vol. 2, Number 2, 8 – 20.
- Daneshy, A. A. (2016). “Effect of Dynamic Active Fracture Interaction (DAFI) on Activation of Natural Fractures in Horizontal Wells”. SPE 181328 presented at the 2016 SPE ATCE, Dubai, UAE, Sept. 26 – 28.
- Nagel, N., Zhang, F., Sanchez-Nagel, M., Lee, B. (2013-a). “Quantitative Evaluation of Completion Techniques on Influencing Shale Fracture ‘Complexity’”. ISRM International Conference for Effective and Sustainable Hydraulic Fracturing, 20-22 May, Brisbane, Australia.

Thomson, D. W., Nazroo, M. F. (1998). "Design and Installation of a Cost Effective Completion System for Horizontal Chalk Wells Where Multiple Zones Require Acid Stimulation". SPE Drilling and Completion, Sept. 1998, 151 - 156 .

Yost, A. B. II, Overbey. W. K. Jr., Wilkins, D. A., Locke, C. D. (1988). "Hydraulic Fracturing of a Horizontal Well in a Naturally Fractured Reservoir: Gas Study for Multiple Fracture Design" SPE 17759 presented at the Gas Technology Symposium, Dallas, TX, June 13-15.