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## **Designing Completions in Horizontal Shale Gas Wells - Perforation Strategies**

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### **Abstract**

Horizontal cased hole completions have become the accepted practice for completing wells in many shale gas plays. There has been a great deal of focus on how to optimize these completions. One of the most important, yet least discussed, concepts in horizontal shale completion optimization strategies is how to perforate to optimize for both placement efficiency of the hydraulic fracture treatment as well as production.

Some of the perforation scheme characteristics that typically need consideration are as follows:

- The number of perforation clusters for each fracture stage
- The optimum number of perforations per cluster
- The distance between perforation clusters
- The length of each perforated interval
- Shot density, phasing and perforation charge type
- Optimal location to place the clusters

Taking into account all of these considerations and using an optimized perforation strategy can be the difference between placing a fracture as per design or experiencing high treatment pressures throughout the stimulation treatment and prematurely aborting the job part way through. Even more importantly, properly engineered perforations can improve overall production by ensuring an equal fracture treatment through each perforation cluster as well as improving wellbore connectivity to the fracture.

This paper looks at all these outlined aspects through a number of different means including a literature review, the use of simulation tools, and case studies from the Marcellus shale. Ultimately, a strategy for optimized perforations is presented with specific focus on shale gas horizontal wells in the Marcellus with further application to other shale gas plays.

### **Introduction**

The technology for designing and completing horizontal wells in shale plays has improved significantly over the last decade, especially in the North American market. Operators are constantly learning new techniques, starting with slickwater fractures, adopting hybrid techniques, and more recently introducing pillar fracturing in shales. The understanding of these reservoirs has also greatly improved, allowing operators to better know where and how to place their laterals and to understand the geology they are working with. Drilling tools and techniques are being created to get to the target faster and more accurately, and even surface seismic is being used to highlight areas of the field that hold the greatest opportunity. However, with all this innovation, one of the questions that still remain unanswered is what is the optimal way to stage and perforate a horizontal shale completion.

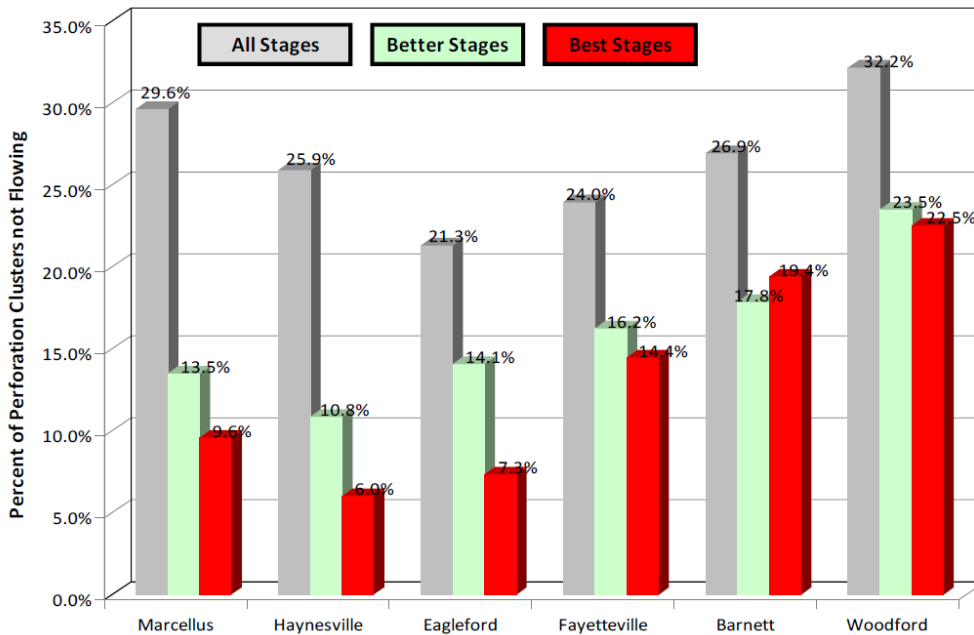
The optimal perforating strategy needs to take a number of considerations into account. First and most important is that during fracture stimulation the perforations should not cause an excessive restriction to flow in such a way that would jeopardize a treatment. This might be caused by such things as insufficient flow area through the perforations or possibly the

creation of multiple competing fractures. The second goal which an optimal completion strategy should have is that every perforation cluster receives equal volumes of stimulation fluid and thus has connection to the reservoir. Any perforation that is shot and not opened is in effect wasted. In addition, perforating strategies need to ensure sufficient drainage from the reservoir during production.

### The number of perforation clusters for each fracture stage

One of the most prevalent questions on designing a completion for horizontal shale gas wells is how many perforation clusters should be treated simultaneously. In an ideal situation, one would want perforation clusters spaced along the lateral to all be treated with a single fracture treatment, not requiring any intervention between stages such as setting plugs or perforating. However, the reason that this does not work is that the stimulation treatment most likely enters a small fraction of the perforation clusters available, leaving the majority of the lateral unstimulated. On the other end of the spectrum, an operator may want to stimulate each cluster individually, which then ensures that each cluster along the lateral is equally stimulated. The obvious problem with this is that while it would most likely provide the best stimulation treatment possible, the cost and lack of efficiency render this technique unprofitable. This is why a balance needs to be made.

When determining the number of perforation clusters to place within a stage, the goal should be to fit as many clusters in a stage while still allowing equal distribution of the stimulation fluid. One of the best ways to evaluate the effectiveness of cluster count is through the use of production logs run in the horizontal well. A recent study of horizontal production logs across several basins (Miller et al. 2011) showed that on average approximately one in four perforation clusters are not producing, and in the Marcellus shale that number increases to almost 30% (**Fig. 1**).



**Fig. 1 — Percentage of all perforation clusters that are not producing. Gray bars include all fracture stages. Green is for stages producing from 110% to 150% above the average rate. The red bars are for stages producing greater than 150% the average rate (Miller et al. 2011).**

The Miller et al. (2011) study also attempts to look at the effect of the number of perforation clusters utilized (**Fig. 2**). In this comparison, a very clear trend is established that demonstrates how the number of perforations that are not producing increases with the number of perforation clusters shot within a single stage. In addition, it seems there is a clear indication that six perforation clusters per stage or more results in an unacceptable number of nonproducing perforations.

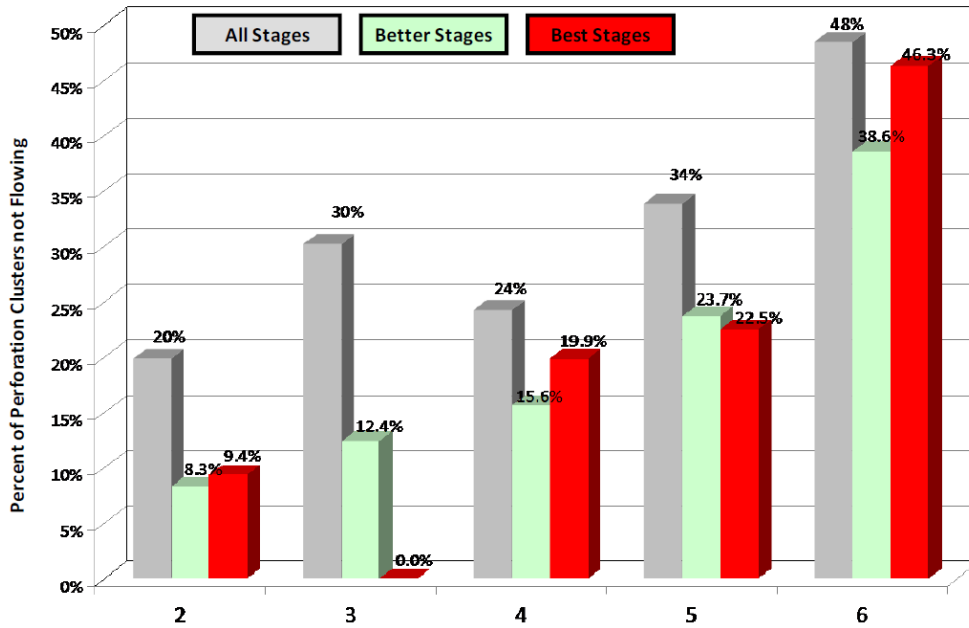


Fig. 2 - Perforation cluster productivity as a function of clusters utilized per fracture stage (SPE 144326)

Ketter et al. (2006) showed similar results, in which reducing the number of clusters per stage resulted in improved microseismic coverage. This is being realized as a common trend within the industry to treat laterals with more stages at a reduced stage length containing fewer clusters.

While increasing the cluster count per stage allows for more options for the fluid to travel to, and thus may be a cause for perforations to not produce, one also needs to investigate the flow regime within the wellbore during fracturing operations. Take an example of a horizontal well with 5.5”-in. pipe and a pump rate of 80 bbl/min. If there are five perforation clusters, each taking 16 bbl/min of fluid, that means that the flow rate in the horizontal after the first perforation is 64 bbl/min, after the second, 48 bbl/min, and so forth until the last perforation cluster has a flow rate of only 16 bbl/min. Most would agree that experience would show that pumping a slickwater fracturing treatment at 16 bbl/min would result in proppant settling in the wellbore.

To calculate the minimum rate required to transport particles of a particular size, one can use the WASP equation (Etchels 1994). For example, in a 5.5”-in. pipe with a 5”-in. ID, 16 bbl/min relates to a velocity of approximately 11 ft/sec Using the WASP equation:

$$v_t = F[2g(s-1)D]^{1/2} (d_p/D)^{1/6} \dots\dots\dots(1)$$

where  $v_t$  is the minimum transport velocity, F is an empirical constant that varies between 0.4 and 1.5, D is the pipe diameter, g is the acceleration due to gravity, s is the ratio of particle and fluid densities and  $d_p$  is the particle diameter, one can calculate that the minimum flow rate to transport 40 mesh sand is about 4 ft/sec. This number represents the absolute minimum velocity required to transport sand and does not take into account such factors as irregularities in the casing such as casing collars, deviations other than horizontal, or the inertial effects of slurry changing direction to exit through a perforation, all of which could promote additional settling.

The velocity of 11 ft/sec mentioned in this example also makes the assumption that fluid is entering each cluster at the same rate. Evidence from production logging and microseismic fracture monitoring has shown that this is rarely the case, however, and thus if the last cluster receives less than the average fluid rate, it becomes far more conceivable that sand can settle out in the wellbore. This may be the reason why there are fewer perforations contributing when six or more clusters are used in a single stage.

Because of this effect, and to ensure proppant transport at all times, this author recommends that the minimum rate per perforation cluster be designed such that it exceeds 3 times the critical velocity obtained in the WASP equation. Thus in 5”-in.-ID pipe using 40 mesh sand, a minimum pump rate of 17.5 bbl/min per cluster is recommended for a minimum surface

pumping rate of approximately 85 bbl/min in a five-cluster fracture design. This recommendation is based on field experience using microseismic fracture monitoring.

## Perforation Design

In designing the completion of a horizontal shale well, the perforations need to be viewed as chokes to flow. This typically might be seen as a deterrent, causing increased treating pressures, and a purely operationally focused approach might lead one to place as many perforations as possible with as large an entrance hole as possible, but this is not always the best strategy. By manipulating the size and number of perforations, one can in effect promote the diversion of treating fluids to all clusters equally. This is done by a limited entry approach, which was discussed back in 1963 by Shell Oil (LaGrone and Rasmussen 1963).

In simple terms, the limited entry technique is achieved by choosing perforation diameter and number of perforations such that the anticipated injection rate produces sufficient velocity through each perforation to create a pressure differential between the hydraulic fracture and the wellbore. This pressure differential is typically in the range of several hundred PSI. Because perforation friction varies directly with the pumping rate, increasing the rate through one perforation also increases the differential pressure exerted through that perforation, thus diverting fluid to other perforations that may not have as much velocity going through them.

For example, consider the beginning of a treatment in which only half of the perforations are open and accepting fluid. As the rate increases, the differential pressure across the perforations accepting fluid rises, increasing the total pressure inside the wellbore. The goal is to increase the pressure to a level high enough to activate the perforations that are not accepting fluid (because there is little to no flow through these perforations, the hydraulic pressure from the wellbore can be transmitted directly to the formation, allowing a higher pressure to be applied at the point of these perforations compared to the ones already accepting fluid).

To further enhance the effectiveness of the limited entry perforation design, if the stresses along the wellbore are known (for example, through the use of sonic logging), perforations can be adjusted to balance this difference in stress. Because fluid tends to travel to the lower-stress interval preferentially, fewer perforations can be put at this low stress point, with more at higher-stressed intervals. Using an iterative process, one can balance the perforations in such a way that equal flow travels through each cluster.

## Perforation: Entrance Hole Diameter

To decide which perforation charges to use for a limited entry style design, obviously the perforation diameter must be considered. If the entrance hole (EH) in the casing is too large, then it becomes difficult to build up enough back pressure. If, on the other hand, the perforation is too small, then there may be problems placing the proppant. According to laboratory tests (Gruesbeck and Collins, 1982), to prevent bridging of proppant in the near wellbore, the perforation diameter should be eight to ten times larger than the average proppant diameter. This takes into account factors such as variance between nominal and actual hole sizes as well as gun positioning and variation in proppant diameters. This gives a lower bound to the perforation size, and with this in mind, the perforations should be designed such that they can create a sufficient pressure drop.

Typical levels of pressure drop range from 500 to 1000 psi for each perforation (Ketter et al. 2006); (Stegent et al. 2010); (McDaniel et al. 1999). This pressure drop can be calculated using the following equation:

$$\Delta p = \frac{0.237 \times q^2 \times \rho}{2 \times C_d^2 \times d_f^4 \times n^2} \dots \dots \dots (2)$$

where  $q$  = flow rate,  $\rho$  = fluid density,  $C_d$  = discharge coefficient (0.6 can be used for the initial perforations if no other data is known),  $d_f$  = perforation diameter, and  $n$  = number of perforations. Using this equation, getting approximately 600–700 psi of pressure drop requires 2 bbl/min per perforation for a 0.42-in. hole, 2.5 bbl/min per perforation for a 0.48-in. hole, and 3 bbl/min per perforation for a 0.52-in. hole.

When estimating EH diameter, it is important to note that the values obtained through API Section 1 test results may be misleading, and may over estimate values of EH and penetration of shape charges. This is because these tests are performed on unstressed concrete. Thus, more effective models should be used such as those developed by Harvey et al. (2010,2012).

## Perforation: Depth of Penetration

In addition to EH diameter, the question of optimum depth of penetration for perforations often comes up. Laboratory experiments (Behrmann and Elbel 1991) showed that in cased hole environments, fractures initiate at the base of the perforation near the sandface, and thus penetration extension beyond 4 to 6 inches is not required. However, those tests were conducted in large sandstone blocks with the borehole drilled without applied stresses. More recent tests (Behrmann 2012) have been conducted in shale blocks where the borehole was drilled with the rock under stress. The far field stresses were maintained during cementing the casing, perforating and fracturing. Significant wellbore breakouts with an extent of approximately one wellbore diameter were created. Tests using both big hole (BH) charges, and deep penetrating (DP) charges were conducted, resulting in lower breakdown pressure when DP charges were used. Thus, providing better agreement with field observations that DP charges used in fracture operations were better than BH charges provided that the EH was sufficient as discussed above. As a result of these tests, a formation penetration of ~1-1.5 times the wellbore diameter is suggested.

## Perforation: Cluster Length

The length of the perforation cluster should be dominated by the limited entry design and is primarily based on the number of perforations required to achieve this goal. For the case of orthogonal fractures to the wellbore, it has been recommended to keep perforation cluster length to less than four times the wellbore diameter (El Rabaa 1989) to minimize the creation of multiple fractures, which could lead to elevated treating pressures. However, more recent small scale block tests (Behrmann 2012) suggest that this cluster length should be reduced to two wellbore diameters in order to minimize the initiation of multiple competing fractures. However, as the cluster length is reduced, the number of perforations is also reduced requiring an increase in the casing hole diameters while maintaining sufficient penetration depth without increasing the perforation friction pressure drop. This requirement drives the operator toward premium charges.

## Perforation: Phasing

In the Marcellus shale, the overburden is typically the largest stress. Because of this, it is predicted that the weakest points in the rock are typically at the top and bottom of the wellbore (Hsiao 1987). Taking this into account, one can see an obvious advantage in shooting perforation clusters oriented to the top and/or bottom of the wellbore. The concern, however, with having a perforation along the bottom of the wellbore is that proppant settling could potentially plug these perforations. In addition, if the perforation gun is not centered in the wellbore, it tends to lie on the bottom, causing a larger hole diameter on the bottom and smaller on top. The combination of these effects may result in the effective perforation diameter being smaller than expected, with ineffective perforations at the bottom or top of the wellbore. As a result, some operators have begun to shoot only the top of the wellbore. The downside of this method of perforating is that typically a reduction in shot density is required versus alternative phasing strategies, which results in larger intervals being shot. In addition, orientation of the guns must be considered. Though typically gun orientation in a horizontal well is done using a weighted sub, any deviation from perforating in the vertical access could lead to extraordinarily high breakdown and treating pressures and may result in problems placing proppant.

The alternative to this is 60° phasing, which is currently the most common phasing method used and maximizes the probability that perforations will exist along the top and bottom of the hole without the requirement of orienting the perforating gun. This method has a very strong track record for success and should be considered. One concern here is that perforations along the side of the casing may be ineffective because these areas typically represent the highest stress. Another concern is that one or more longitudinal fractures parallel to the wellbore are created before any transverse fractures are initiated. These fractures only extend approximately one to two wellbore diameters in height after which they are terminated by the maximum horizontal stress. The extent along the wellbore is not known, however, from production logs there is insufficient fracture permeability for adjacent clusters to communicate (Behrmann 2012) The creation of one or more longitudinal fractures is dependent on the gun orientation and also on the gun-to-gun orientation, both being random. More guns mean a greater probability of multiple longitudinal fractures.

It is clear that both options have advantages and disadvantages. Due to the standardization and proliferation of 60° perforation phasing in horizontal shale wells, this may be the best option where no problems are observed. However, if difficulties arise placing high proppant concentrations or excessive treating pressures during fracturing then 180° phasing should be considered. Alternately, a new gun system has been developed with special phasing (SLB 2012) that provides 100% effective shots with all perforations directly connected to the transverse fracture. This has the potential to reduce or even eliminate near wellbore issues related to perforation phasing.

### Distance Between Perforation Clusters

There are a number of different theories out regarding the optimal spacing between perforation clusters. In the Barnett shale, microseismic studies have shown an optimal spacing of 1.5 times the fracture height (Fischer 2004). In the Eagleford formation, one study found the optimal spacing between perforation clusters to be between 35 ft and 40 ft. Modeling performed in the Marcellus has showed optimal spacing at approximately 70 ft (Jacot et al. 2010).

However, it should be noted that using “rules of thumb” can be very dangerous and may not apply from shale to shale or even within a single basin. The key to optimizing cluster spacing is to maximize the drainage of the reservoir while balancing costs. How the reservoir drains is not only a function of reservoir properties such as permeability and porosity but also of the hydraulic fracture characteristics and includes how complex the fracture is, the orientation and scope of the stimulated fracture network, and the conductivity of the induced fracture network, to name a few. To analyze this, a complex simulation needs to be performed such as that outlined by Cipolla et al. (2011a). This is best done when microseismic monitoring is used to calibrate a complex fracture simulator (**Fig. 3**), which in turn can be used to match production results (**Fig. 4**). Once the results are calibrated, differing stage lengths can be modeled to optimize net present value (NPV).

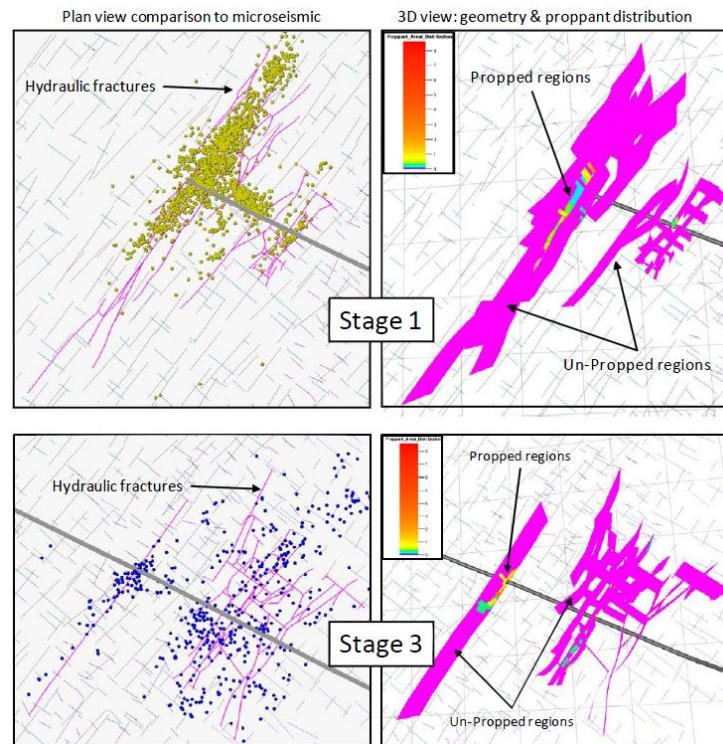


Fig. 3—Microseismic fracture monitoring is used to calibrate an unconventional fracture model (Cipolla et al. 2011a).

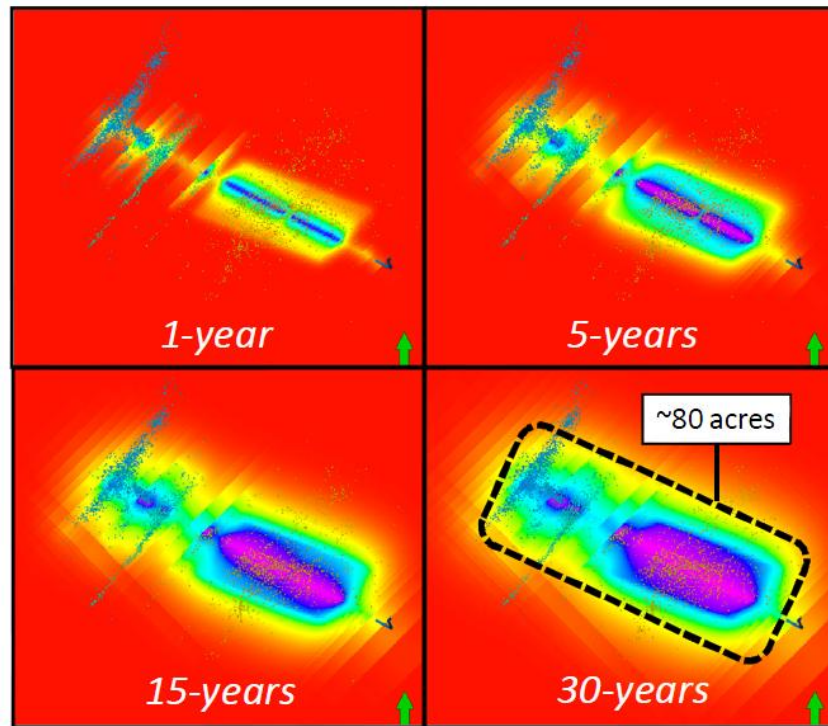


Fig. 4—Unconventional fracture model is used to simulate drainage patterns, allowing for optimization of fracture stage spacing (Cipolla et al. 2011a).

### Optimal Location to Place the Clusters

When trying to determine where exactly to place perforation clusters, one needs to understand the concept of lateral heterogeneity in shales. An excellent description is given by Miller et al. (2011) as follows:

Heterogeneity in lateral wellbores is primarily controlled by wellbore geometry and vertical variations in rock characteristics, which occur at an extremely small scale in shale reservoirs.

Miller further explains that

Vertical and lateral variability must be addressed, preferably during drilling, in order to increase the potential of economic success. Doing so has shown to positively impact shale productivity.

This increase in productivity was outlined by Baihly et al. (2010) in which a 75% increase in production on average was seen when wells were drilled using logging-while-drilling (LWD) measurements to understand the lateral heterogeneity and design their completion based on it. Another example in the same paper shows a 20% increase in production versus offsets when selective stage spacing is used. The reason for this production increase is documented in many papers including Waters et al. (2006). When attempting to initiate multiple transverse fractures from a single wellbore at the same time, the fracture always initiates in the lowest stressed zone because with geometric spacing this is the path of least resistance. This phenomenon is often seen in microseismic monitoring where stress logs have been run, such as in **Fig. 5**. In this image a minimum stress log is visualized along the wellbore, with the areas in red representing the low-stress regions. It is clearly seen that even though there are five perforation clusters available for flow, the vast majority of events occur at the perforations located in the lowest stress. This creates an unequal distribution of the fracture treatment pumped and may result in unstimulated perforation clusters, impeding flow during production.

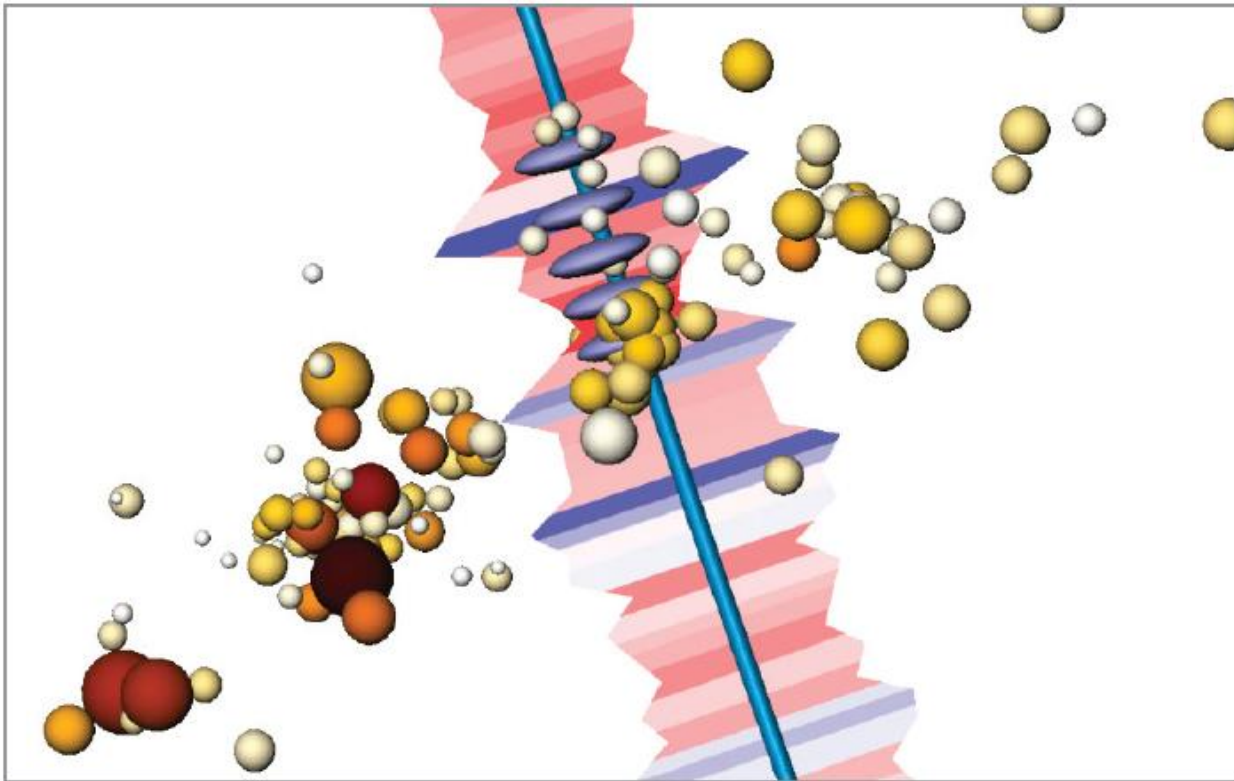


Fig. 5—Microseismic monitoring overlay on minimum stress log with red indicating low stress and blue indicating high stress.

By optimizing the locations where the perforations are placed, one can greatly improve the distribution of induced fractures along the wellbore, which helps better drain the reservoir in a consistent manner. The technique behind selecting perforation locations is explained in numerous papers, most notably in Cipolla et al. (2011b). In the process outlined in this paper, the perforation locations are based on pay zone quality along the lateral when stresses are similar in all areas within a stage. That is, perforations are placed in areas where the rock properties are best in terms of both ability to create and propagate fractures (completion quality) and the quality of the reservoir in terms of being able to produce hydrocarbons (reservoir quality). Typical parameters that make up completion quality include minimum horizontal stress, Young's modulus, and Poisson's ratio. Reservoir quality also can be characterized by numerous variables, including porosity, permeability, and kerogen content.

If, however, stress variations are high, then perforation locations are selected in such a way that each perforation cluster is in similarly stressed rock and limited entry calculations are performed to determine the distribution of perforations among fracture units to promote the equal distribution of fluids.

### Case Study: Perforation Placement

This technique of using rock quality to determine perforation locations is demonstrated in Fig. , which represents a horizontal wellbore that was drilled in the Marcellus shale using LWD tools including sonic and spectroscopy. The first three tracks show some of the properties that were acquired during drilling: gamma ray, porosity, and minimum horizontal stress gradient.

The fifth track indicates the completion quality of the rock at each specified depth and was calculated using an algorithm that favors rocks based on low stress, low Poisson's ratio, and high Young's modulus. By doing this, the algorithm highlights areas that will tend to produce the best fracture characteristics.

The sixth track on Fig. shows the reservoir quality of the rock. It is calculated using an algorithm that favors high porosity, high levels of kerogen, and high permeability.



It should be noted that the criteria for good and bad reservoirs and completion quality can vary well by well. In this instance, the goal is not to determine the viability of this well to produce, but instead is to rank the best and worst intervals within the lateral relative to the rest of the interval of interest.

There is now sufficient information available to determine the optimal placement of the perforations. Algorithms such as those developed by Cipolla et al. (2011b) use this data to come up with an optimized perforation design wherein perforation clusters remain within like rock, with an emphasis on targeting intervals with both good completion quality characteristics as well as good reservoir quality characteristics.

Using the other recommendations within this paper, perforations were shot at 60° phasing with an average hole diameter of 0.42 in. A limited entry style design was used where fewer perforations were placed in lower stressed intervals and more were placed in higher stressed intervals with the average rate through each perforation at 2 bbl/min.

The results of the implementation of these changes in this case study showed an improvement in production of over 50% compared with production in offset wells. Additionally, significant drops in treating pressures during the stimulation treatments were seen. All jobs were pumped to completion using this technique with no forced pump stoppages due to excessive pressures at surface (Schlumberger 2012). As a result of this success, the operator has continued to use this strategy on subsequent wells, obtaining sonic and lithologic measurements in the lateral and using this data to design the completion.

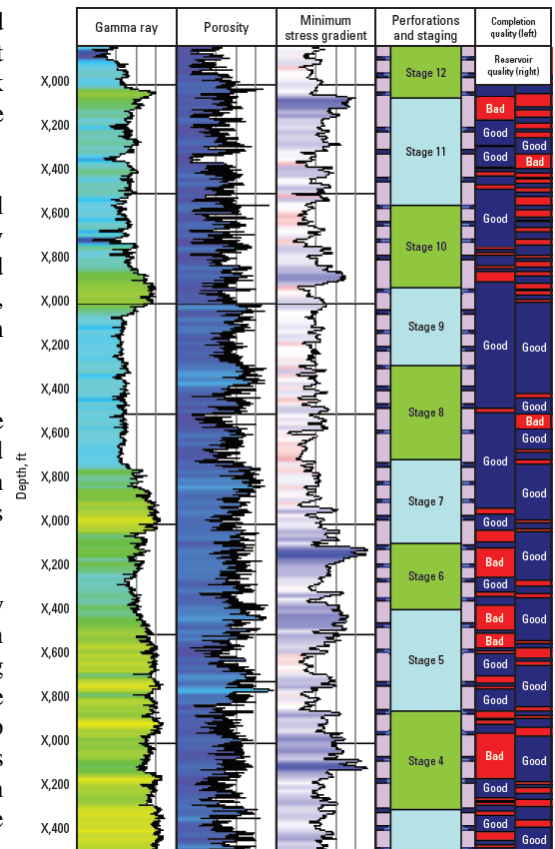


Fig. 6—Example of perforation picking using lateral measurements.

## Conclusions

There have been many examples cited that demonstrate how an optimized perforation strategy can significantly improve productivity in a horizontal cased hole shale well, including the following:

- Ensuring that the number of clusters being simultaneously treated is limited to the point where the average stimulation pumping rate/cluster maintains a linear velocity of 3 times the critical velocity so that proppant does not settle in the wellbore.
- A limited entry perforation design is used with an average pressure drop across a perforation ranging from 500 to 700 psi.
- If the stress regime is known, the perforations should be made so that more perforations are placed in higher stressed rock and fewer in lower stressed rock to produce a choking effect of the perforations that balances the difference in wellbore stresses.
- A perforation phasing of 60° should be considered; however, if excessive pressure is encountered, 0° oriented phasing shooting the top of the wellbore may reduce the pressure.
- Perforation clusters should be kept as small as possible with maximum shot density, while keeping cluster length to less than 2 times the wellbore diameter.
- Simulation and NPV should be used to calculate the optimal distance between perforation clusters.
- Data obtained in the lateral, such as stresses and lithology, should be used to optimize perforation design.

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