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Accounting for near-wellbore fracture behavior to unlock the potential of unconventional gas wells

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Abstract

Despite ongoing engineering efforts, unconventional horizontal gas wells completed with the multi-stage hydraulic fracturing technique are not yet producing to their full potential, as a meaningful proportion of clusters are producing marginally - if at all. In this paper, we advocate that the near-wellbore behavior of the fractures could explain some of that behavior. We propose a method involving a test well completed with the pin-point fracturing technique to sample the variability in the near-wellbore behavior. With the help of a dedicated fully coupled hydraulic fracturing simulator, we show that the optimum number of clusters per stage can be selected taking into account this new information. The various steps of this method are illustrated with an example.

Introduction

In shale gas reservoirs, hydraulically fractured horizontal wells are the completion method of choice. Reservoir engineering often dictates the desired spacing and extent of the fractures to be placed (Xiong, 2017, Shahkarami et al., 2016). The placement of all hydraulic fractures must then be performed efficiently in order to ensure that the reservoir economics are met. In particular, in a horizontal well drilled in a homogeneous reservoir, all planned fractures should have a similar final conductivity. A clear correlation between amount of proppant placed and productivity increase have been established for a number of unconventional plays (Coulter et al., 2004, Lafollette & Holcomb, 2011, Izadi et al., 2013). Therefore for best performance, the hydraulic fractures must all be initiated, propagated and have received similar amount of proppant.

One key component of the cost optimization of unconventional developments is to place several hydraulic fractures during a single injection stage. The ultimate aim is to reduce as much as possible the number of injection stages for a given well (accounting for other cost constraints such as bringing sufficient injection power on-site) while ensuring the successful placement of all the desired fractures. Field observations have, however, clearly shown that not all the fractures in the same stage produced equally. A significant amount of planned fractures appears not to produce at all, while most of the production comes from a discrete number of fractures (see Miller et al., 2011 among others). Several studies suggest that having less fracture/clusters per stage improve the success of fracture placement and thus the ultimate production of the well (e.g. Ugueto et al., 2016). This can be traced back to the fact that during a stage, not all the perforation clusters take the same amount of fluid – as observed via fiber optics monitoring (Molenaar et al., 2012, Ugueto et al., 2016). There is therefore an economical optimum between the number of injection stages and the number of fractures per stage.

Despite a number of engineering efforts in recent years, the overall percentage of clusters contributing to the production of a well is still far from 100%, and the production between clusters is highly variable (Slocombe et al., 2013). Theoretical modeling of the hydraulic

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fracturing process (e.g. Lecampion & Desroches, 2015(a) and 2015(b)) clearly demonstrate that, within a stage, not all the designed fractures propagate. In other words, the simultaneous propagation of several fractures from a horizontal wellbore is not a robust process – and the flow rate received in each fracture is not uniform during injection, resulting in an uneven volume of proppant placed per fractures.

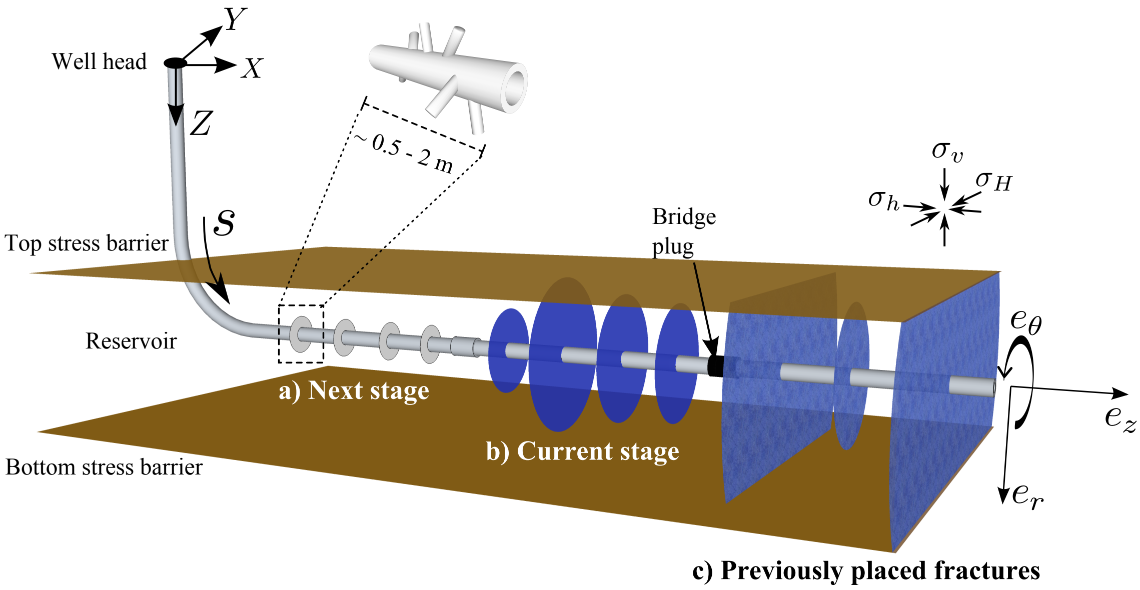

Figure 1 Sketch of multistage fracturing of a horizontal well (adapted from Lecampion & Desroches, 2015(a)).

The multistage problem

It appears from both numerical simulation and field observations that the number of clusters per stage does play a role in the production performance of a well.

In this work, we take the view that a better understanding of the underlying driving mechanisms related to the placement of simultaneous fractures can improve design decisions - and ultimately economics for a given play, without disrupting the current operations. Ultimately, one aims at a method to select the optimal location and number of clusters per injection stage.

A number of methods have already been proposed and implemented to tackle this problem. A first set of methods relies on improved characterization of the variation of stresses, or many embodiments of “frackability”/”brittleness” indices (see Yang et al., 2013 for a critical review), to select where to place the perforation clusters by minimizing heterogeneities in formation properties between clusters within a stage, and designing appropriate perforation strategy via limited entry design. Various levels of improvement have been observed (Slocombe et al., 2013, Lim et al., 2014). It is important to note that such methodologies do not consider the physical processes of the simultaneous initiation and propagation of multiple hydraulic fractures. These also do not provide help in selecting the number of fractures per stage.

A second class of techniques are based on the injection of diverting agents – typically solids, from ball diverters to special mixes of particles – to plug the fractures taking the most fluid and then promote the initiation or propagation of other fractures. It is unclear, however, how the timing of adding diverting agents affect the overall production performance, and experience shows that several diverting pills are helpful as the number of clusters per stage increases (e.g. Viswanathan et al., 2014).

Finally, the idea of placing each fracture one by one (thus forgetting the idea of propagating several fractures at once) obviously solves the problem of non-homogeneous fracture and proppant placement. A number of sleeve completions systems have been proposed to do so in a time efficient manner. However, because of costs and operational complexity, such systems still remain marginally competitive compared to accepting the performance variability associated with current multistage fracturing practices.

Understanding unconventional well completion by combining models and observations

In order to go one step further from previous contributions, one needs to combine wellbore hydraulics, hydraulic fracture mechanics, and a refined near-wellbore description to solve for the evolution of fluid partitioning between fractures during the stimulation of a given stage. In particular, one needs to better understand how reservoir heterogeneities, sensitivity to perforations and injection strategies ultimately impact the fracture/proppant placement performance. With such knowledge in hand, one could make a better-informed choice on the number of cluster per stages, cluster spacing, etc.

In what follows, we study the effect of these design and reservoir variations on a test well on which extensive characterization has been carried out (Desroches et al. 2014). In particular, in this well, the near-wellbore behavior was successfully quantified by a combination of step-down tests on single-entry fracture treatments. Moreover, detailed characterization of the formation mechanical properties was obtained via advanced cuttings analysis.

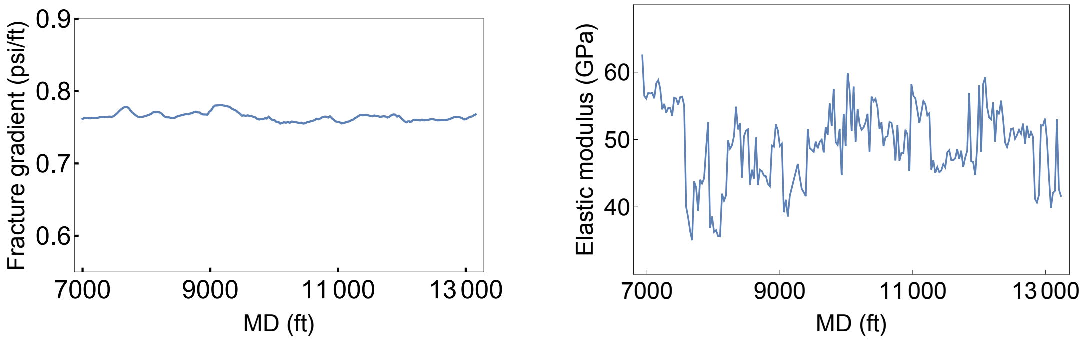

Figure 2 Fracture gradient (left) and Elastic modulus (right) profile along this test well. See Desroches *et al.* (2014) for more details.

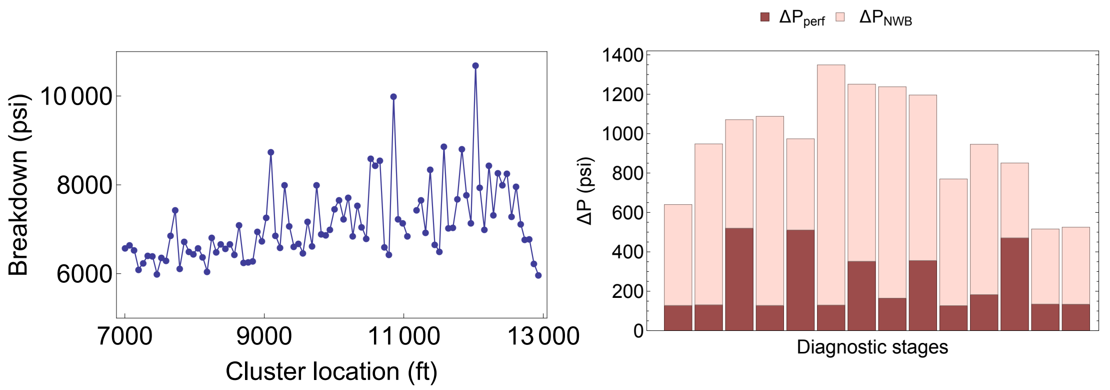

Figure 3 Breakdown pressures of the different clusters (MD along the well) and split between the perforation entry friction and the near-wellbore friction for the 14 diagnostic stages.

We display in Figure 2 the reconstructed stress profile and elastic properties along the horizontal section of this wellbore. All clusters were treated via a single entry completion technique. The left panel of Figure 3 displays the fracture breakdown (maximum) pressure for each cluster, whereas the right panel displays measured excess entry pressure (at nominal rate) due to perforation and wellbore tortuosity. It is striking to see that even though the formation mechanical profile appears relatively homogeneous, very large variations of fracture initiation and excess entry pressures are observed. Such a large heterogeneity in the fracturing behavior – only tens of feet apart – can be traced back to the complex near-wellbore fracture behavior as observed in laboratory experiments (Weijers et al., 1994) – see also Bunger & Lecampion, 2017 for a review. Due to the local stress concentration around the wellbore and perforations, the created fracture rotates more or less smoothly to finally align with the preferred fracture plane governed by the virgin in-situ state of stress. This rotation is amplified in horizontal wells compared to vertical wells. It is also impacted by the presence of natural fractures and other discontinuities (see Bughardt et al., 2015). As a result, in addition to the pressure drop through the perforations, a non-linear pressure drop occurs through the complicated fracture geometry (with several branches and potential pinch-points) in the few meters over which the fracture re-orientation takes place. As discussed in Suarez-Rivera et al. (2013), the connection between the wellbore and the main body of the fracture can be divided in two zones (1 and 2 in Figure 4). In the well of interest mentioned above, this additional pressure drop (at the nominal rate) can be as large as 5 times the perforation friction (see Figure 3, right panel). It is inherently variable along the well as it depends on local / small-scale effects below the resolution and radius of investigation of current technologies.

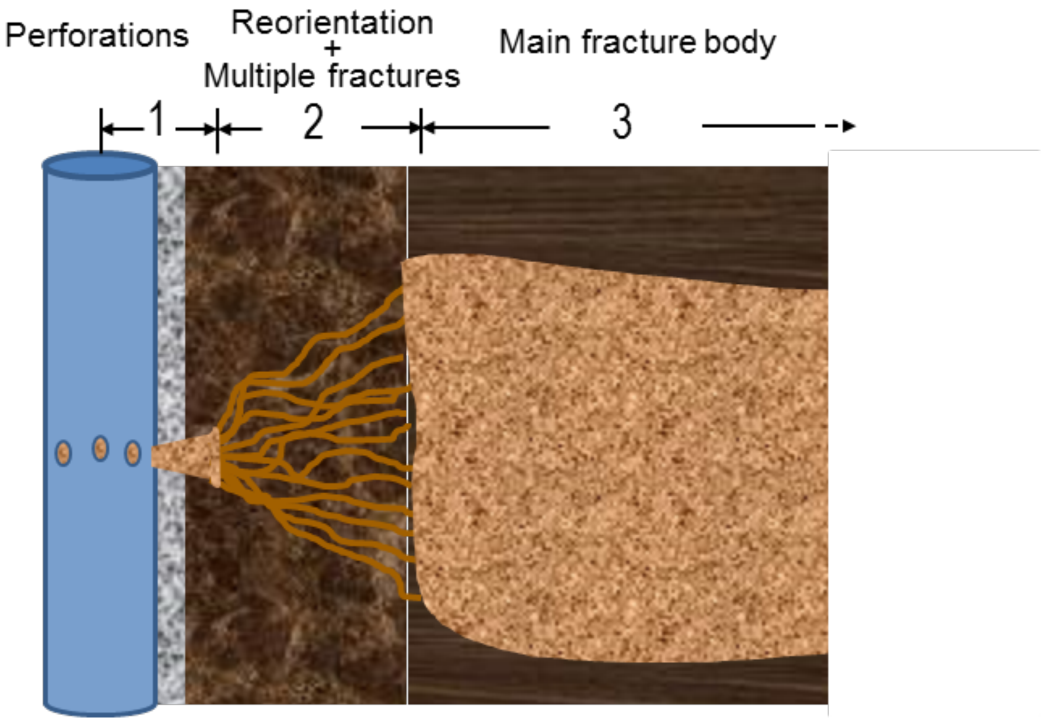

Figure 4 Schematic of the connection between the wellbore and the far-field part of the fracture. A first pressure drop ($f_{p,i}Q_i^2$) associated with the perforations occurs in region 1, another pressure drop ($f_{t,i}Q_i^{\beta}$) is associated with region 2 where the fracture re-orients itself toward its far-field preferred orientation (region 3).

In this work, we do not try to account directly for such small-scale variations but we consider its macroscopic effects on each cluster. This macroscopic effect is embodied in a non-linear relation between pressure drop Δp_i between the pressure in the wellbore (in front of the perforations cluster) and the pressure a few meters inside the fracture *i* beyond the re-orientation zone:

$$\Delta p_i = f_{p,i}Q_i^2 + f_{t,i}Q_i^{\beta} \qquad (1)$$

where $f_{p,i}$ is a coefficient function of fluid density and perforation cluster geometry, and $f_{t,i}$ and β are coefficients related to the near-wellbore tortuosity (fracture re-orientation) effects (see Nolte & Economides, 2000 for more discussion of the previous formula). It is important to note that the tortuosity coefficients can be obtained in-situ via step-down tests. As already mentioned, it can vary from fracture to fracture within a stage. This is particularly striking for the test well discussed here, but similar variations have been observed previously (e.g. Weijers et al., 1994).

We use a model for the concurrent initiation and propagation of multiple hydraulic fractures from a horizontal well accounting for stress heterogeneities, perforation friction, stress shadow between fractures as well as near-wellbore fracture behavior (Lecampion & Desroches, 2015(b)). This numerical model is unique in the sense that it fully couples well hydraulic flow, fracture initiation and propagation. It therefore solves for the fluid partitioning between growing fractures during injection: the surface pump rate Q_p is not necessarily evenly distributed in the different fractures of a given stage. For example, for a stage with N clusters, the rate entering each fracture may not necessarily be Q_p/N but the result of the complete simulation. Notably, the fluid partitioning is impacted by stress interactions between growing fractures (stress shadow) but also the near-wellbore pressure drop described in eq.(1).

With this model and proper characterization of both the formation along the well and the near-wellbore tortuosity, we can investigate the performance of a number of scenarios, varying the number of clusters per stage, injection rates, etc.

We post-process the results of this hydraulic fracture simulator using the amount of fluid injected in a given cluster as a proxy for the amount of proppant placed in each fracture, and thus the production performance of each fracture. Figure 5 displays the fluid intake (divided by the designed value corresponding to an even partitioning) for each cluster along the well for a) the case of a multistage completion of this well with two clusters (fractures) per stage and b) six clusters per stage. As expected, the variation of the fluid intake is greater for six clusters per stage compared to two: the maximum fluid intake is larger, and, more interestingly, the number of clusters that do not propagate at all is also larger.

It is also interesting to look at the histogram of the fluid intake for all the clusters in the well as a function of the number of clusters per stage (see Figure 6). We found that this histogram provides the best way to select the number of clusters per stage as it encapsulates the inherent variability along the well. For that particular well, it appears that the distribution changes significantly from 1 to 3 clusters per stage, but does not significantly change for a larger number of clusters per stage (up to N=6, as we didn't test a larger number of clusters per stage). Based on these results, depending on cost, one could select a completion strategy based on 1, 2 or 6 clusters per stage: as the cost efficiency is largest for the largest N, the scenarios for N=3 to 5 naturally drop out of consideration.

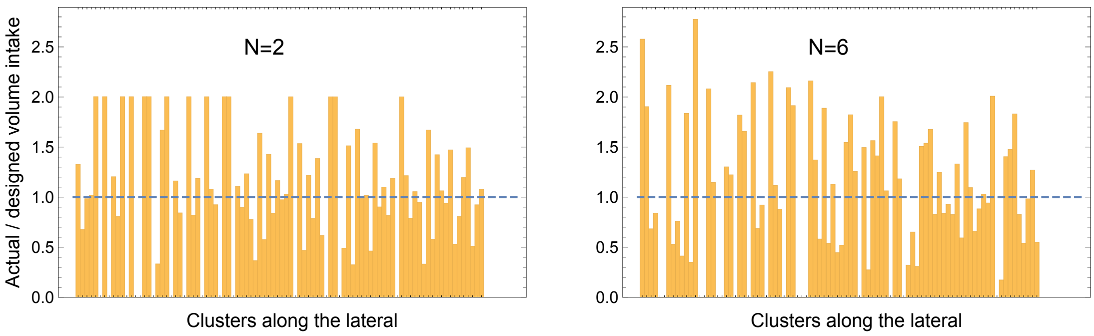

Figure 5 Fluid volume taken by each cluster along the well compared to that corresponding to even fluid partitioning between all clusters: 2 clusters per stage (left) and 6 clusters per stage (right).

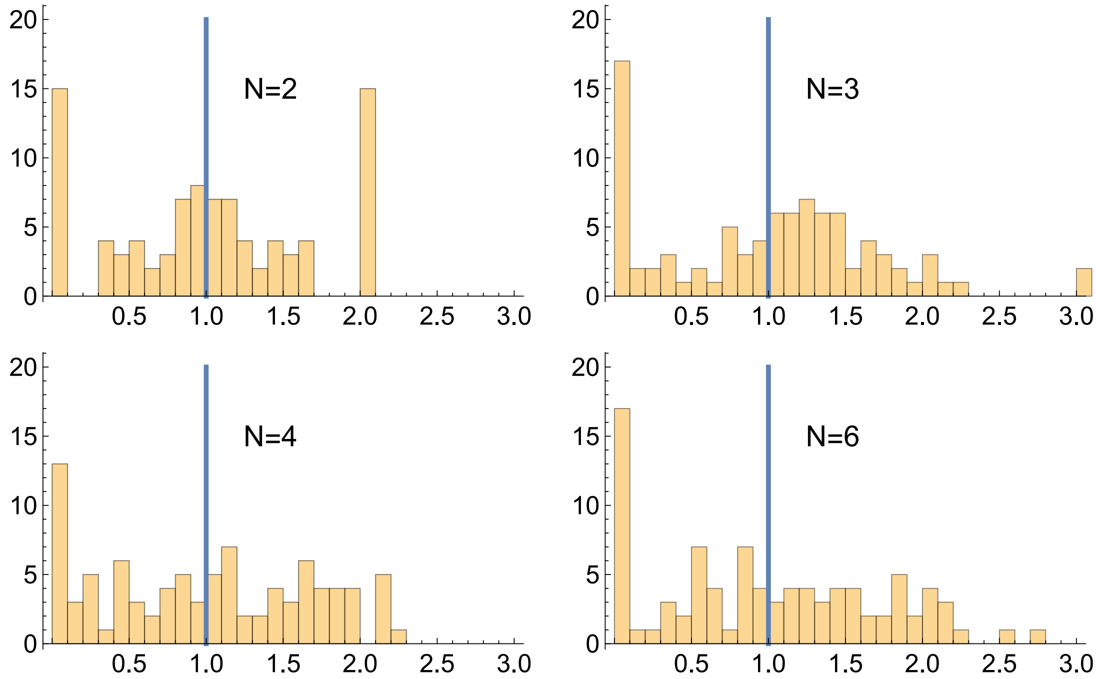

Figure 6 Histograms of the volume intake versus the designed one over the entire well for different numbers of clusters per stage, N=2, 3, 4 and 6. Note that the blue bar would correspond to a perfectly partitioned case – where all the fractures would receive the designed volume.

Discussion

From the above example, where there are little variations of mechanical properties along the well, we observe that variations of near-wellbore fracture behavior from cluster to cluster can completely dominate the flow partitioning between fractures within a given stage. This typically results in only one or two fractures per stage completely dominating fluid intake. With regards to heterogeneity of stress that could be characterized and used in an engineered limited entry design, robustness simulations (Lecampion & Desroches, 2015(b)) have shown that the resulting stimulation is very sensitive to small design variations. This lack of robustness of the limited entry design is expected to be further enhanced when accounting for the erosion of perforations when proppant hits the perforations.

It is anticipated that the spacing between clusters will also influence the optimum number of clusters, because of the influence between neighboring fractures (also known as "stress-shadow", see Bunger & Lecampion, 2017 for a review): if fractures are closer to each other, more may preferentially close, changing the fluid partitioning between clusters. Because this influence is fully taken into account in the simulator used in this work, the proposed method can also be used to compare scenarios with different spacing between clusters, and provide an optimum number of clusters tailored to the desired cluster spacing (which is often determined from reservoir engineering requirements).

The method described here only considers the starting point for developing adequate fracture conductivity in all planned fractures, i.e. that all fractures are taking the designed amount of proppant slurry. It does not consider what happens after shut-in, like proppant settling during fracture closure, proppant embedment after fracture closure, or the effect of subsequence operations like coiled-tubing milling or flowback. It is therefore not a replacement for ensuring that adequate fracture conductivity will be retained after pumping has stopped.

On the other hand, the method described here allows to look at the potential benefit of reducing the near-wellbore tortuosity friction, i.e. how much of a reduction would be needed to significantly change the optimum number of clusters. Different perforation techniques can then be tried to reach that level of reduction, for example jetted perforations to ensure that the fracture initiates in a single plane transverse to the wellbore, or oriented perforations – e.g.

perforating only at some select angle with respect to the top of the well to make sure that all fractures initiate transversely to the wellbore.

Finally, let us note that the method that we have presented requires a test well with extensive characterization, especially a large enough number of single entry diagnostic treatments to sample the near-wellbore variability. However, there is no other means today to properly characterize the near-wellbore effect during stimulation, as step-down tests carried out on multi-cluster stages will not provide that information. Furthermore, provided that the fluid and pumping strategy is not changed, this method will provide a clear basis for the optimization of the number of clusters per stage, which can then be applied to all the wells in the same pad – or possibly a wider area.

Conclusions

Advances in the engineering of hydraulically fractured horizontal wells over the past few years have yielded important improvement in production, albeit not as much as anticipated. For example, the percentage of producing clusters remains significantly under 100%, even with the best possible formation characterization.

The main results of this study are as follows:

- Engineered completion designs are not very robust to variations of formation properties – especially when accounting for the erosion of perforations when proppant hits the perforations. We refer the reader to Lecampion & Desroches, 2015(b) for a complete discussion.
- Furthermore, variations of near-wellbore fracture behavior can completely dominate the flow partitioning between fractures within a given stage. This typically results in only one or two fractures per stage completely dominating fluid intake.
- Near-wellbore fracture behavior can be easily measured with a step-down test on a single cluster treatment. Variations of this near-wellbore behavior can thus be sampled. We recommend completing a test well with single entry and multiple step-down tests for that purpose.
- From the heterogeneity characterized on the test well, the optimum number of clusters per stage – balancing the need for efficiency with that of an even proppant distribution between clusters - can be determined via the simulation of multiple scenarios as described above. This optimal number of clusters per stage can then be applied to the other wells in the pad or in the area.

Our results demonstrate that accounting for the near-wellbore fracture propagation (which depends on both formation and wellbore properties as well as pumping parameters) is a key input to determine the optimal number of perforation clusters per fracturing stage, such that every designed fracture receives the same amount of proppant.

We propose a method consisting of measuring the heterogeneity of the near-wellbore friction during fracture propagation by performing single entry fracturing treatments along a representative horizontal well. This characterization of the heterogeneity of the fracture response in the near-wellbore can then be used in conjunction with a numerical simulator to select the most advantageous number of perforation clusters per stage, such that proppant is placed in each fracture at the desired spacing for optimal production.

Acknowledgments

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