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Horizontal Well Completion, Stimulation Optimization, And Risk Mitigation

Larry K. Britt, NSI Fracturing, LLC and Michael B. Smith, NSI Technologies, Inc.

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Abstract

Horizontal wells have become the industry standard for unconventional and tight formation gas reservoirs. Because these reservoirs have poorer quality pay, it takes a good, well-planned completion and fracture stimulation(s) to make an economic well. Even in a sweet spot in the unconventional and tight gas reservoir, good completion and stimulation practices are required; otherwise, a marginal or uneconomic well will result. But what are good completion and stimulation practices in horizontal wells? What are the objectives of horizontal wells and how do we relate the completion and stimulation(s) to achieving these goals? How many completions/stimulations do we need for best well performance and/or economics? How do we maximize the value from horizontal wells? When should a horizontal well be drilled longitudinally or transverse? These are just a few questions to be addressed in the subsequent paragraphs.

This paper focuses on some of the key elements of well completions and stimulation practices as they apply to horizontal wells. Optimization studies will be shown and used to highlight the importance of lateral length, number of fractures, inter-fracture distance, fracture half-length, and fracture conductivity. These results will be used to discuss the various completion choices such as cased and cemented, open hole with external casing packers, and open hole "pump and pray" techniques. This paper will also address key risks to horizontal wells and develop risk mitigation strategies so that project economics can be maximized. In addition, a field case study will be shown to illustrate the application of these design, optimization, and risk mitigation strategies for horizontal wells in tight and unconventional gas reservoirs.

This work provides insight for the completion and stimulation design engineers by:

1. developing well performance and economic objectives for horizontal wells and highlighting the incremental benefits of various completion and stimulation strategies,
2. establishing well performance and economic based criteria for drilling longitudinal or transverse horizontal wells,
3. integrating the reservoir objectives and geomechanic limitations into a horizontal well completion and stimulation strategy, and
4. identifying horizontal well completion and stimulation risks and risk mitigation strategies for pre-horizontal well planning purposes.

Introduction

For many years, operators have utilized hydraulic fracturing to improve the performance of vertical, deviated, and horizontal wells. Although often successful, these operators have reported more difficulty fracture stimulating deviated and horizontal wells than that which occurred during the stimulation of vertical wells in the area. Generally, the difficulties of fracture stimulating deviated and horizontal wells are evidenced by increased treating pressures and elevated post-fracture Instantaneous Shut-In Pressures.

Horizontal wells have been successfully applied in a number of field applications over the years. Recent applications in the Barnett Shale Formation in the Fort Worth Basin have raised attention to the application of this technology to Tight Formation and Unconventional Gas Resources. Though the application of horizontal well completion and stimulation technology has been successful, the completion and stimulation technology applied in each varies widely. It is the objective of this evaluation to develop an understanding of each of these "completion and stimulation styles." Through this understanding, reservoir, completion, and stimulation criteria will be developed to aid in identifying which strategy, if any, to apply in a given asset to maximize the production rate, reserve recovery, and economics.

Horizontal wells have been shown to improve well performance in oil and gas reservoirs especially when coupled with hydraulic fracturing[1-7]. Completions for multiple fractured horizontal wells have been a constant issue since the technology became popular in the early 1990's. In the North Sea, several methods of perforating, stimulating, and isolating have been utilized to improve well completion efficiency and fracture stimulation placement[8-12]. Although effective, these completion techniques struggled to find an on-shore commercial market in tight and unconventional gas reservoirs[13-16] where more completions and fractures are desired per foot of lateral length.

In tight and unconventional gas reservoirs, greater operational control and reliability are necessary for operational success and to prevent erosion of project economics. Numerous papers have described the problems associated with open hole or slotted liner completions where limited to no control of the injection fluids is available[17-19]. In these works, microseismic and/or tiltmeters were used to show that in an uncemented slotted liner completion[17], the resulting fractures were concentrated at the heel and toe of the well with no effective stimulation seen through most of the lateral. In one paper[18], tiltmeters showed that a transverse fracture was created at the toe of the lateral and a longitudinal fracture created at the heel. In another integrated study[19], post-fracture diagnostics confirmed that fractures rarely distributed themselves over the entire length of the horizontal section. Depending on hoop stress, fracture initiation may occur at the heel or tow of the lateral, but without positive isolation there is no real control over the location or number of fractures generated. Perhaps more importantly, there is no control over the stimulation fluid and the resulting dimensions of the created fractures. In these low permeability formations, zonal isolation has been shown to be critical to multiple fractured horizontal well success[20-22]. In the Barnett Shale Formation, for example, pump down plugs[23-24] and external casing packers[25-26] have been utilized to improve isolation and improved fracture stimulations have been the result. The pump down plug system is used in cased and cemented horizontal well applications and allows nearly complete control over the injected fluids. The external packer system, although an openhole application, does allow the design engineer to exert some control over the fracture stimulation(s), especially when compared to the "pump and pray" completion style (i.e, fully open hole or uncemented slotted liner completions).

This paper will review multiple fractured horizontal well objectives for tight and unconventional gas reservoirs. Geomechanical influences such as principal stresses, hoop stress, and fracture interference will be addressed in the context of horizontal well objectives in these reservoirs. This paper will show that it is these geomechanical influences, coupled with the horizontal well objectives, that should drive the selection and implementation of a completion system. Further, reservoir, completion, and stimulation risks and risk mitigation strategies will be discussed and a tight gas case study shown to detail and document the real world implications of the theoretical problems addressed.

Discussion

Horizontal Well Objectives:

The objective of horizontal wells in tight formation and unconventional gas reservoirs is to improve the gas production rate, rate of recovery, and project economics, just as in vertical wells. However, the completion and well stimulation(s) in horizontal wells are far more complex. The role of this section is to establish a framework for developing the horizontal well objectives. The best way to do that is with a reservoir simulator and economic model. Through the integration of this data, the critical objectives for horizontal well success can be determined. The subsequent paragraphs will detail and document an analysis of reservoir, fracturing, and economic parameters and their importance inr maximizing horizontal well economics. The simulator used in this analysis is the numeric three-dimensional single phase gas simulator in STIMPLAN. The simulator has an automated horizontal well gridding feature, and it has been used for horizontal well studies for nearly two decades.

The base case reservoir and economic parameters used in this study are shown in Table 1. These base case parameters are fairly typical of tight formation gas reservoirs in the United States. However, numerous sensitivity tests were conducted to ensure that the assumptions made and used in this economic study were reasonable and didn't unduly influence the results.

First, let's look at the effect of lateral length on horizontal well performance. Figure 1 shows a plot of Net Present Value versus the Number of Fractures as a function of Lateral Length for the base case parameters from Table 1. As shown, with one fracture in the horizontal well in a tight gas reservoir, there is marginal economic benefit of increased lateral length. However, as the number of fractures increases, the benefits of

Table 1: Base Case Reservoir & Economic Parameters

Reservoir Parameters:

Net h ft	□	*Sw*	Re acres	Pi psi	k md
100	0.07	0.3	640	2,000	0.01

Economics Parameters:

Price $/mcf	*IR* %
5	10

Vertical Section, M$	3.00
Lateral to 2000 $/ft	350.00
Lateral beyond 2,000 ft, $/f	400.00
Completion < 9, M$/Stage	0.05
Completion > 9, M$/Stage	0.50
Stimulation Costs, $/ft^2	1.20

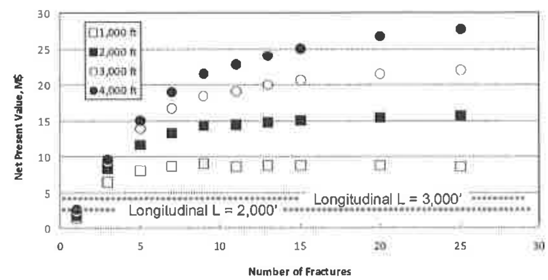
Fracture Parameters:

x_f ft	$k_f w$ mdft
1,500	250

present values for the 1,000 ft, 2,000 ft, 3,000 ft, and 4,000 ft lateral are 8.8 M$, 15.1 M$, 20.6 M$, and 25.1 M$, respectively. Note, that this benefit is realized regardless of the natural gas price. It is sensitive to the cost of drilling the lateral, however, but even then the cost of extending the lateral would need to increase by 16.5 times (i.e, from $400/ft to $6,600/ft) for the economic benefits of increased lateral length to be fully eroded.

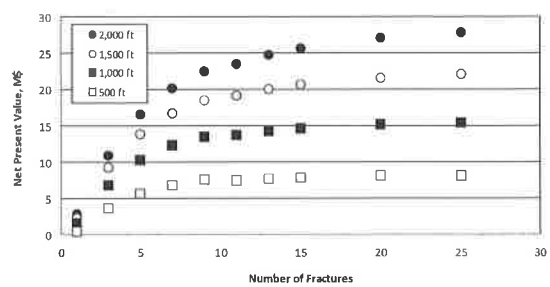
Also shown on this plot are the economic values of a 2,000 foot longitudinal and 3,000 foot longitudinal horizontal well. As shown, the values of these longitudinal horizontal wells are 2.7 M$ and 4.9 M$, respectively. Thus, the net present value of a longitudinal well in a tight gas and unconventional reservoir is far less than that of a multiple fractured transverse well.

Figure 1: Economic Effect of Lateral Length



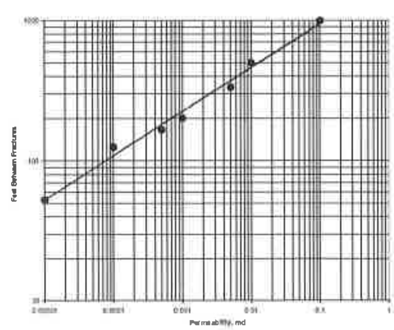
Next, let's look at the effect of fracture length on horizontal well economic performance. A 3,000 foot lateral was considered with fracture half-length varying from 500 to 2,000 feet, as shown in Figure 2. The economic benefits clearly increase as the fracture half-length increases. For example, for the case where 15 completions/fractures are created the net present value for the 500 ft, 1,000 ft, 1,500 ft, and 2,000 ft fracture half-length is 7.7 M$, 14.6 M$, 20.6 M$, and 25.6 M$, respectively. Note that economic benefit of increased half-length is realized regardless of the natural gas price. Much like the benefit of increased lateral length, that of increased half-length is sensitive to the fracturing costs; however, it would require the costs per square foot of fracture to increase by 108 times (i.e, from $1.2/ft^2$ to $130.0/ft^2$) for the economic benefits of increased fracture length to be fully eroded.

Figure 2: Economic Effect of Fracture Length



In this analysis we have looked at the economics of various parameters as a function of the number of completions/fractures. Figures 1 and 2 distinctly show that there is an economic benefit from increasing the number of completions/fractures, but clearly there are diminishing returns. This can be best seen by reviewing either the 1,000 foot lateral case in Figure 1 or the 500 foot fracture half-length case in Figure 2. In either example, when the number of completions/fractures exceeds 8 to 10 no additional economic benefit is realized. Of course, as the lateral length and fracture half-length increases, the number of completions/fractures from which an economic benefit is derived increases as well. Further, this optimum number of completions/fractures is a function of reservoir permeability. To investigate this further, an optimization of the number of completions/fractures was conducted using the base case properties and varying reservoir permeability. This optimization is shown in Figure 3, a plot of the optimal distance between completions/fractures as a function of the reservoir permeability. This figure represents the result of hundreds of simulations, as displayed in Figures 1 and 2, and provides an interesting horizontal well design objective, whether in an unconventional shale gas, tight formation gas, or conventional gas reservoir. As shown, for a reservoir permeability of 0.0001 md the optimal distance between completions/fractures is slightly over 100 feet, while for reservoir permeabilities of 0.01 and 0.1 md the optimal distances between completions and fractures are nearly 500 and 1,000 feet, respectively. The higher the permeability, the greater the optimal distance between completions and fractures is. This indicates that the economic driver for multiple fractured horizontal wells is the communication or interference of the created fractures, and this communication is largely driven by the matrix permeability of the reservoir. Although not the subject of this paper, this raises an interesting question regarding the economic value of a naturally fissured medium, especially when the fissures require injected fluids to activate.

Figure 3: Optimum Completion Spacing versus Permeability



In this section, we showed the key economic drivers of horizontal wells which are the lateral length and fracture half we do not have total control over how long a fracture we are able to create. As a result, a critical part of establishing horizontal well objectives is to understand the basis of fracture design (i.e, in-situ stress, Young's Modulus, and leak-off) so that a reasonable economic projection can be made.

As one final thought, we showed the benefits of fracture length and lateral length on the horizontal well economics. Other parameters such as fracture conductivity, net pay, and reservoir pressure were investigated. Their effects on the horizontal well economics were found to be fairly predictable and not nearly as important to the completion process as length (i.e, either lateral or fracture). However, fracture conductivity was found to be important for the case where non-Darcy convergent flow was deemed important. As such, the effect of fracture conductivity on horizontal well performance will be discussed in a subsequent section on horizontal well risk mitigation strategies.

Geomechanics of Horizontal Well Completions:

Why do fracture stimulations in deviated and horizontal wells differ from fracture behavior in vertical wells? To understand this difference, we need to consider rock mechanics and more specifically the state of stress and how it impacts the hoop stresses around the borehole. In a vertical well, the principal stresses are rectangular and they include a vertical stress, σ_v, maximum horizontal stress, σ_{Hmax}, and minimum horizontal stress, σ_{hmin}. Figure 4 shows a schematic of the various stress states (stress environments) and the relationship of the principal stresses for normal, Strike-Slip, and Reverse/Thrust fault environments.

Figure 4: Schematic of Conventional Stress States

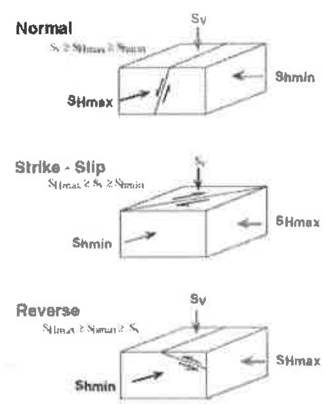
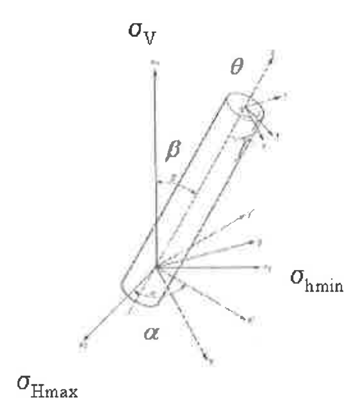


Figure 5: Schematic of Stress State-Radial Coordinates



In a normal stress environment, a fracture opens against the minimum horizontal stress (fracture opening/closure pressure) and propagates in the direction of the maximum horizontal stress (perpendicular to the minimum horizontal stress). In this environment, the induced stress concentrations or hoop stresses are maximized (breakdown pressures are high) when the minimum and maximum horizontal stresses are equal or nearly so. When the maximum to minimum horizontal stress ratio is large (>>>1), the hoop stresses are small and the breakdown pressure is minimized. Figure 4 shows this state of stress in rectangular coordinates. It should be noted that in deviated wells, the principal stresses are similar except that they are expressed in radial coordinates. This is shown in Figure 5, which is a schematic of a deviated wellbore that has a relation to the rectangular coordinates of σ_v, σ_{Hmax}, and σ_{hmin}. In addition, the well deviation, β, the well azimuth (deviation from maximum horizontal stress), α, and where on the borehole the breakdown occurs, ϕ, displays the tangential stresses associated with deviated wellbores. The works of Bradley[27] and Deily & Owens[28] were used to translate the equations for the rectangular stress state to the radial stress state, and a program based on these equations was developed. This was used to assess the breakdown pressure as

a function of β, α and $\tilde{\phi}$, assuming the "normal" stress state where the overburden is the maximum principal stress, the maximum horizontal stress is the intermediate principal stress, and the minimum horizontal stress is the minimum principal stress. Assuming that the overburden stress is 1 psi/ft (10,000 psi for a 10,000 foot vertical well), the intermediate and minimum principal stresses are 7,500 and 6,000 psi, respectively, the reservoir is normally pressured (4,300 psi), the tensile stress is 300 psi, and Poisson's Ratio is 0.20, the breakdown pressure for horizontal wells with azimuths of 0 (longitudinal), 30, 60, and 90 (transverse) degrees are 4,000, 4,100, 5,980, and 8,500 psi, respectively. Thus, the breakdown pressure for a horizontal well aligned with the minimum horizontal stress (σ_{Hmax} >>> σ_{hmin}) is more than two times the breakdown pressure for a horizontal well aligned with the intermediate stress. Figure 6 shows a plot of breakdown pressure versus theta (location on the wellbore) for varied well azimuths. As shown, for any azimuth, the lowest breakdown pressure occurs at a theta of 0 degrees which indicates that the horizontal well, regardless of nearly five times that of the top and bottom. For this particular example, the breakdown pressure for the side of the wellbore is nearly 20,000 psi for the longitudinal case and 18,000 psi for the transverse horizontal well case. For open hole completions and stimulations, the distinction of where on the wellbore breakdown occurs is irrelevant. However, for cased and cemented wells, this distinction is quite important. What if no consideration is given to the perforation strategy in a cased and cemented wellbore? What if the perforations are 30 degrees from the top of the wellbore (theta is 30 degrees)? For the assumptions used in this example, that scenario would result in wellbore breakdown pressures of 8,000 and 11,000 psi for the longitudinal and transverse horizontal well cases, respectively. Thus, the lack of a perforation strategy in a cased and cemented horizontal well can easily result in breakdown pressures two to three times that of an open hole horizontal wellbore. When you hear of a cased and cemented wellbore that couldn't be broken down, ask yourself, what perforation strategy was used?

Figure 6: Wellbore Breakdown Pressures ($\sigma_{Hmax} >>> \sigma_{hmin}$)

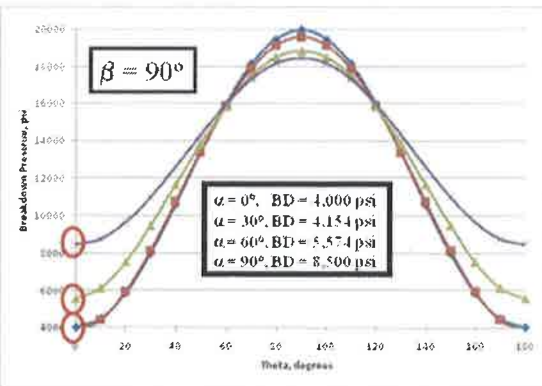


Figure 7: Wellbore Breakdown Pressures ($\sigma_{Hmax} = \sigma_{hmin}$)

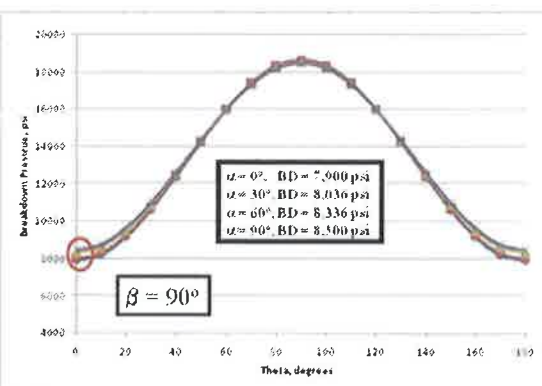
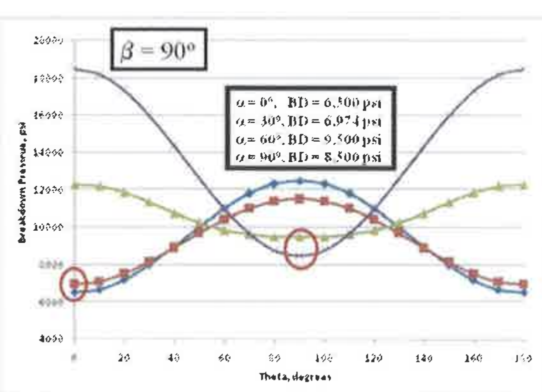


Figure 8: Wellbore Breakdown Pressures ($\sigma_{Hmax} >>> \sigma_{hmin}$)



Next, let's review a "normal" stress condition where the maximum and minimum horizontal stresses are nearly 1. That is, a stress state where the maximum horizontal stress is the weight of the overburden and the intermediate and minimum horizontal stresses are nearly equal. For this example, assume that the overburden stress is again 10,000 psi but the minimum and maximum horizontal stresses are 7,500 and 7,300 psi, respectively. Figure 7 shows a plot of the wellbore pressure versus theta as a function of azimuth for a horizontal well. As shown, the breakdown pressure (where the wellbore pressure is the lowest) occurs at the top and bottom of the wellbore regardless of the well azimuth. Further, when the wellbore is aligned with the maximum horizontal stress (azimuth is 0 degrees), the wellbore breakdown pressure is 7,900 psi. When the azimuth of the wellbore is 90 degrees (transverse) the wellbore breakdown pressure is 8,500 psi. Thus, when the horizontal stresses are equal or nearly so, the difference between the breakdown pressures of an aligned or longitudinal wellbore and a non-aligned or transverse wellbore is minimal (i.e. 600 psi). Compare this to the prior case where the maximum to minimum horizontal stress ratio was much greater than 1 and the difference in breakdown pressure between an aligned (longitudinal) and unaligned (transverse) wellbore was 4,500 psi. Such a difference in breakdown pressure can be readily appreciated if you realize that when the maximum to minimum horizontal stress ratio is greater than 1 ($\sigma_{Hmax} >>> \sigma_{hmin}$) there is a preferred fracture direction, and a potentially large penalty is realized when the wellbore is misaligned with that preferred direction. On the other hand, when there is no preferred fracture direction ($\sigma_{Hmax} \sim \sigma_{hmin}$), from a breakdown perspective it doesn't particularly matter which direction the well is drilled in.

Also note by referencing Figure 7 that even when there is no preferred fracture direction ($\sigma_{Hmax} \sim \sigma_{hmin}$), there is still a strong preference for the horizontal well to breakdown on the top and bottom of the wellbore. Irrespective of azimuth, if a horizontal well is cased, cemented, and perforated on the sides of the wellbore, the breakdown pressures can exceed 18,000 psi for the example cited (i.e. nearly 2.1 times the breakdown pressure for the cased and cemented wellbore with the top and bottom perforated).

What about a Strike-Slip stress environment where the vertical stress (overburden) is the intermediate principal stress and the maximum horizontal stress is the maximum principal stress? Assume that the intermediate stress (overburden) is 7,500 psi for a 10,000 foot vertical well and the maximum and minimum principal stresses are 10,000 and 6,000 psi, respectively. In addition,

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