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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.

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

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 increasing lateral length increases as well. For example, for the case where 15 completions/fractures are created, the net 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.

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 1: Economic Effect of Lateral Length

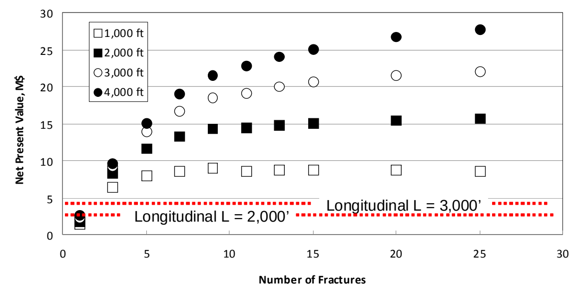
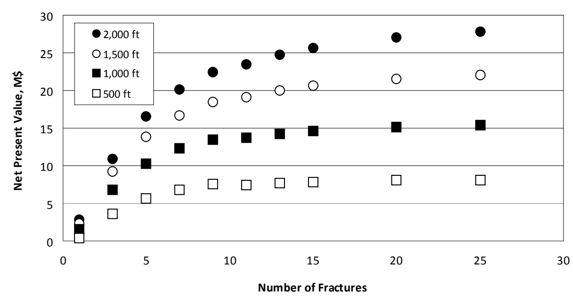
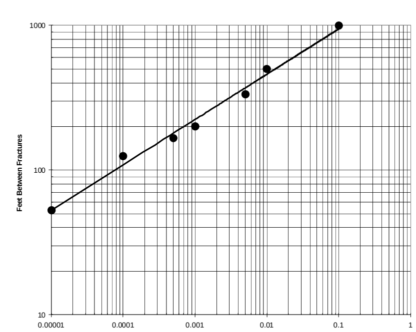


Figure 2: Economic Effect of Fracture Length



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 length. Of the two, fracture half-length is the most important based on the net present value contribution per foot; however, 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.

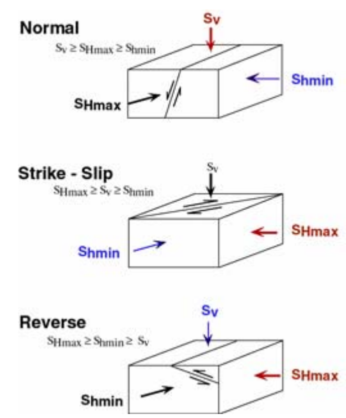


Figure 4: Schematic of Conventional Stress States

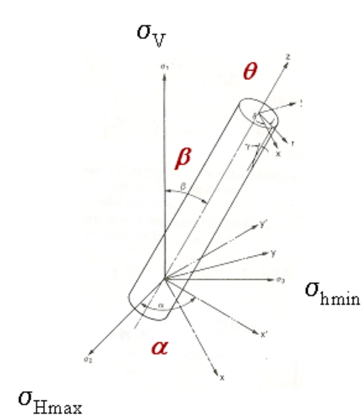


Figure 5: Schematic of Stress State-Radial Coordinates

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 azimuth, will breakdown at the top and bottom of the wellbore. Further, the sides of the wellbore have breakdown pressures 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?

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 (σ_{Hmax}>>> σ_{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 (σ_{Hmax}~ σ_{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 (σ_{Hmax}~ σ_{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, assuming the reservoir is normally pressured (4,300 psi), the tensile

Figure 6: Wellbore Breakdown Pressures (σ_{Hmax} >>> σ_{hmin})

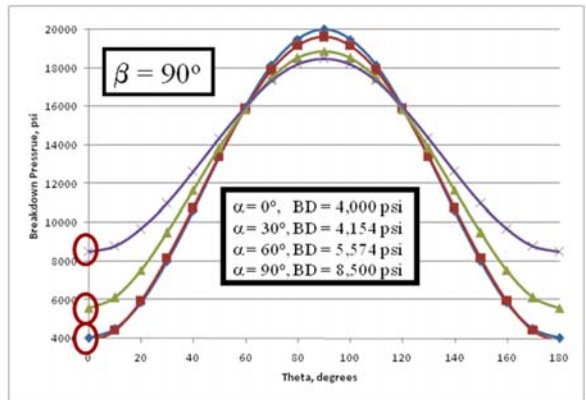


Figure 7: Wellbore Breakdown Pressures (σ_{Hmax} = σ_{hmin})

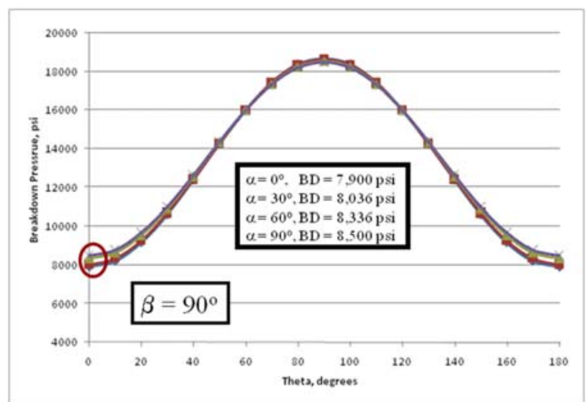
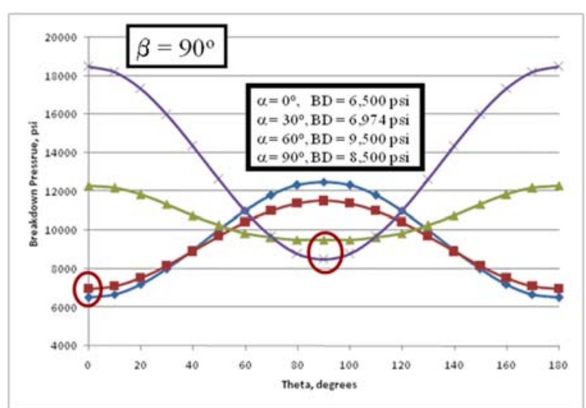


Figure 8: Wellbore Breakdown Pressures (σ_{Hmax} >>> σ_{hmin})



stress is 300 psi, and Poisson's Ratio is 0.20, the breakdown pressures for horizontal wells with azimuths of 0 (longitudinal), 30, 60, and 90 (transverse) degrees are 6,500, 6,980, 6,960, and 8,500 psi, respectively. Thus, the breakdown pressure for a horizontal well aligned with the minimum horizontal stress in a Strike-Slip environment ($\sigma_{Hmax} > \sigma_v$) is more than 1.3 times the breakdown pressure for a horizontal well aligned with the maximum principal and horizontal stress. Figure 8 shows a plot of breakdown pressure versus theta (location on the wellbore) for varied well azimuths. As shown, the lowest breakdown pressure for azimuths of 0 and 30 degrees occurs at a theta of 0 degrees which indicates that for this scenario the well will breakdown at the top and bottom of the wellbore. Further, for azimuths of 60 and 90 degrees, the wellbore has breakdown pressures nearly 1.07 and 1.30 times that of the borehole aligned with a 0 degree azimuth. If we assume that this is a cased and cemented wellbore, we can once again see that the perforation strategy is extremely important. For a longitudinal horizontal well perforated at the top and bottom of the wellbore, the breakdown pressure would be nearly 6,000 psi less than for the wellbore perforated on its sides. Conversely, for a transverse horizontal wellbore in a Strike-Slip stress environment, perforating on the sides of the borehole results in nearly a 10,000 psi reduction in the breakdown pressure compared to perforating on the top and bottom of the borehole.

What about a "reverse" or "thrust" fault environment where the overburden is the minimum principal stress and the maximum and minimum horizontal stresses are the maximum and intermediate principal stresses, respectively? To look at the effect of breakdown pressures in horizontal wells in a "thrust" environment, let's assume that the overburden pressure is 6,000 psi, the maximum horizontal stress is 10,000 psi, and the minimum horizontal stress is 7,500 psi. Assume reservoir pressure, tensile pressure, and Poisson's Ratio are as in the prior examples. Figure 9 shows the results of this analysis as a plot of Wellbore Pressure as a function of theta for various values of azimuth from 0 degrees (longitudinal) to 90 degrees (transverse). As shown, for all "reverse or thrust" stress environment cases, the wellbore breakdown occurs on the sides of the horizontal well (theta is 90 degrees). Further, in this stress environment, the minimum breakdown pressure occurs in the transverse horizontal case and the maximum breakdown pressure occurs in the longitudinal direction. In this stress environment, the breakdown pressure for a 0, 30, 60, or 90 degree azimuth would be 6,500, 5,660, 4,280, and 4,000 psi, respectively. Finally, if you cased and cemented the wellbore and perforated the top and bottom of the borehole, the breakdown pressure for a 0, 30, 60, or 90 degree azimuth would be 20,000, 17,260, 13,620, and 12,500 psi, respectively. Put differently, a cased, cemented, and perforated horizontal well in a reverse or thrust stress environment would be difficult if not impossible to breakdown and is, therefore, a poor completion choice for this stress environment.

Figure 9: Wellbore Breakdown Pressures ($\sigma_{Hmax} = \sigma_{hmin}$)

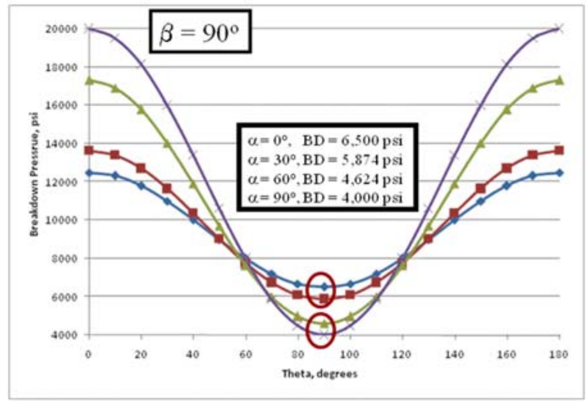


Figure 10: BD Pressures as a Function Of Stress State

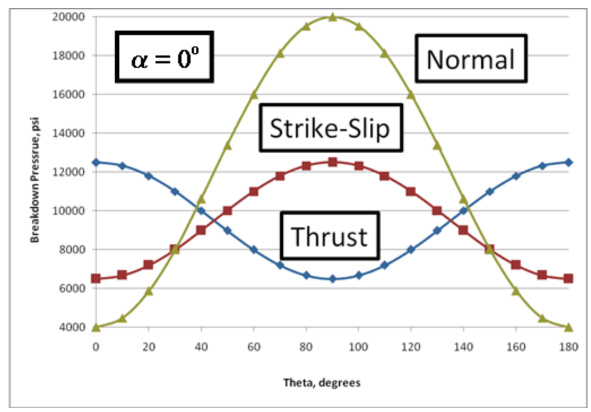
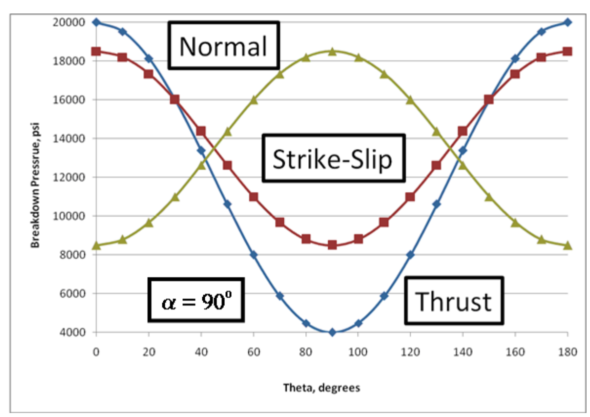


Figure 11: BD Pressures as a Function Of Stress State



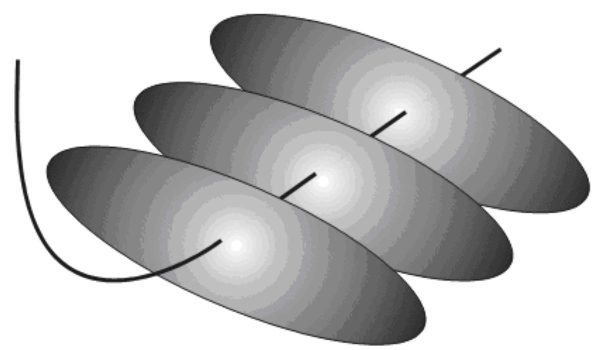
The preceding analysis of breakdown pressures as a function of stress environment highlights how critical it is to understand the state of stress prior to selecting a completion and stimulation methodology. Figures 10 and 11 put this analysis in graphic form as plots of breakdown pressure versus theta for each stress environment and longitudinal (azimuth is 0 degrees) and transverse (azimuth is 90 degrees) cases, respectively. As shown, for longitudinal horizontal wells, the breakdown pressure is lowest for a normal stress environment where the overburden, maximum horizontal, and minimum horizontal stress are the maximum, intermediate, and minimum principal stresses, respectively. In a cased and cemented wellbore with this stress environment, perforate the top and bottom of the borehole (theta is 0 and 180 degrees). For this example, the breakdown pressure in the Strike-Slip or Reverse/Thrust is equal and 2,500 psi higher than the normal stress environment. Note, however, that the location where the breakdown occurs varies from the top and bottom of the well (Strike-Slip) to the sides of the wellbore (Reverse/Thrust). As a result, a perforation strategy is necessary anytime you case, cement, and perforate a horizontal wellbore.

Figure 11 shows a similar plot for a transverse horizontal well. As shown, for a transverse horizontal well, the breakdown pressure is lowest for a reverse or thrust stress environment where the maximum horizontal, minimum horizontal, and overburden stress are the maximum, intermediate, and minimum principal stresses, respectively. In a cased and cemented wellbore with this stress environment, perforate the sides of the borehole (theta is 90 and 270 degrees). For this example, the breakdown pressure in the Normal or Strike-Slip is equal and 2,500 psi higher than the reverse or thrust stress environment. Note, however, that the location where the breakdown occurs varies from the top and bottom of the well (Normal) to the sides of the wellbore (Strike-Slip). As a result, a perforation strategy is necessary anytime you case, cement, and perforate a horizontal wellbore.

Fracture Interference:

As indicated in the horizontal well objectives section, an attractive option for some low permeability formations is multiple, transverse propped fracture stimulations along the length of a horizontal wellbore (as pictured in Figure 12). However, as the fractures get closer and closer along the length of the wellbore, they will begin to mechanically interfere with one another. For a treatment aimed at creating multiple, transverse fractures, this interference may establish an absolute maximum number of fractures that can be created simultaneously. The potential interference is calculated below for the case of long, confined height fractures.

Figure 12: Multiple Fractured Transverse Horizontal Well



The analysis discussed here was conducted using a finite element program, SAP_IV. Along with the results presented here, other simulations were conducted using varying grid patterns to ensure that the grid was sufficiently fine for accurate results. Two separate cases were considered: 1) the case of two fractures, and 2) a case of an infinite series of parallel fractures. Clearly, any real case (as pictured in Figure 12) would consist of both types of cases. That is, for the case in Figure 12, the two end fractures would approximately behave like the “2 fracture” case below, while the center fracture would approximately behave like the “N fracture” case. These cases considered two long, confined height fractures running parallel to one another along their length (as pictured in the inset of the figures below). Figure 13 plots the results for two parallel fractures. First, the width reduction is plotted as a function of dX/H (where dX is the distance between fractures and “H” is the fracture height). This shows that for dX/H=1, the width of each fracture is about 80% of the width of a single fracture (for the same fluid pressure). However, the total width is greater since there are now two fractures!

This is seen in the “Flow Resistance”. For a viscosity dominated fracture behavior, the net pressure at the wellbore is given (approximately) by

$$P_{Net} \propto \frac{E}{H}\left(\frac{Q\,\mu\,L}{E'}\right)^{1/4} \quad \text{or} \qquad P_{Net} \propto E'^{\,3/4} \times Q^{1/4} \;.$$

Thus, for the case of dX/H=1, the width for each of two fractures is 0.8 X W_0, i.e., where W_0 is the width for a single fracture. This is equivalent to a modulus increase by a factor of 1.25 (i.e., 1/0.80). However, the flow rate is now cut by 50% since there are two fractures. Thus, the “flow resistance” is given by

$$E'^{\,3/4} \times Q^{1/4} = (1.25)^{3/4} \times (0.5)^{1/4} = 0.995$$

That is, the “flow resistance” for two parallel fractures with a spacing of dX/H=1 is identical to the flow resistance for a single fracture. For spacings > 1, the flow resistance is actually less than 1 – that is, it would be easier to propagate two fractures than a single fracture so long as dX/H > 1!

The more extreme case would be an infinite series of long, confined height parallel fractures such that every fracture has another fracture on each side. For this case, the fracture interference is plotted in Figure 14, with results somewhat similar to the “2 Fracture” case – but more so.

For example, reviewing the effect on fracture width of fracture spacing, at dX/H=2, the width for each of “N” fractures is about 75% of the width of a single fracture (as compared to 90% for the “2 Fracture” case). However, for spacing (dX/H) of 1 and less, the width reduces sharply (i.e., extreme interference for dX/H <= 1). Converting this to a “Flow Resistance,” again the results show that for dX/h of 1 or greater, the flow resistance is essentially identical to that for a single fracture. That is, one can propagate “N” fracture simultaneously at the same pressure as required to propagate a single fracture so long as dX/H >= 1. However, for dX/H < 1, flow resistance increases sharply. Thus, it would be difficult to create multiple fractures with a spacing less than dX/H=1.

It should be noted that for a “real” case of, say, 5 parallel fractures, the “Flow Resistance” would be somewhat less that the curve plotted in Figure 11. This would be due to the fracture on each end of the series of 5 fractures, since that fracture would be wider (with behavior similar to the “2 Fracture” case). Thus, again (as for the “2 Fracture” case), the “Flow Resistance” would actually be less than 1 for spacing, dX/H, greater than 1! Also note that for both cases (Figures 13 and 14) if the interfracture distance, dx, is greater than twice the fracture height, there is little detrimental impact on fracture width and treating pressures due to multiple propagating fractures. This result for contained fractures is similar to that found for height growth cases[29].

Completion Plan:

Given that the primary objective of multiple fractured horizontal wells is to maximize the well performance and project economics and that these measures are enhanced through longer laterals and fractures, the completion plan should focus on achieving these capabilities. As a result, the completion plan can be summarized by the degree of control over the lateral and fracture stimulation process. In this regard, the completion falls into three scenarios which include (1) total control over the completion (number of completions/fractures and injected fluids), (2) limited control over the completion and injected fluids, and (3) no control over the completion and stimulation fluids. All horizontal well completion methods fall somewhere within this “control spectrum” defined by these scenarios. For example, a cased and cemented wellbore where individual intervals are perforated and fracture stimulated individually would be a completion that allows as much control over the lateral contribution and injected fluids and fracture dimensions as possible, assuming each perforated interval is isolated from the next. Even a cased and cemented completion strategy would fall into more of a limited to no control scenario if each set of perforations was not positively isolated from the next. An example of this might be the use of induced stress diversion whereby the pressure in the preceding fracture stimulation is used to divert the stimulation fluid into the next set of perforations. Another example would be if multiple intervals over several hundred feet are perforated in a completion stage

Figure 13: Fracture Interference for Two Fractures

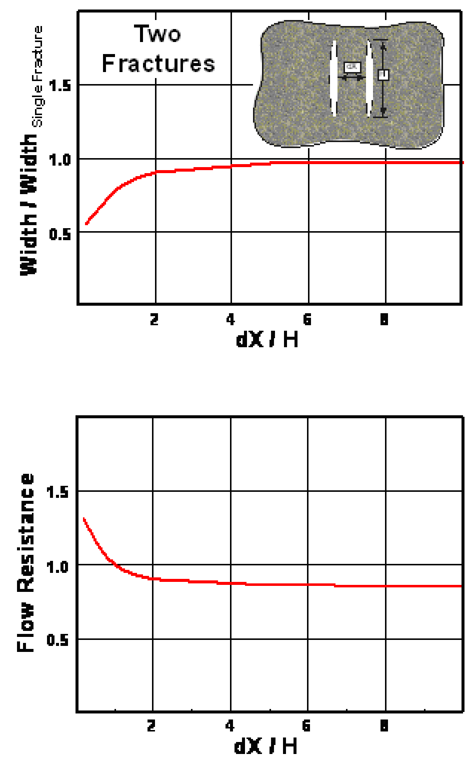
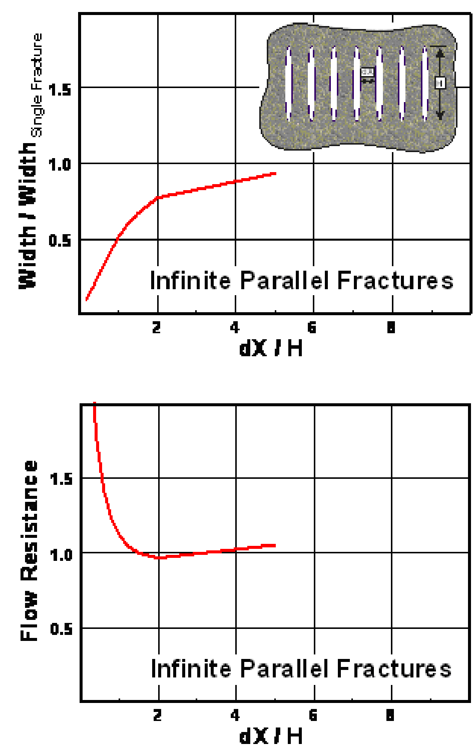


Figure 14: Fracture Interference for Infinite Array of Fractures



and stimulation fluids pumped. We can't determine which or how many sets of perforations are stimulated or if the desired fracture dimensions are achieved in any perforation set. In this example, we have taken the completion method with the greatest potential control (cased and cemented wellbore) and turned it into a completion strategy that has limited control over the achievement of the horizontal well objectives.

With this simple completion philosophy stated one might ask, why complete horizontal wells with anything other than casing, cement, perforations, and isolation? Although preferred to achieve control, the use of this technique may not be warranted due to the reservoir objectives and the stress state. In an unconventional gas resource with extremely low permeability and large fracture height, for example, the reservoir objectives may be for a fracture every 100 feet. In a 3,000 foot lateral this might require 31 separate completions and stimulations. In this scenario, it is unlikely that you could case and cement a wellbore, perforate, fracture stimulate, and isolate a stage 31 times without encountering significant trouble time either during the completion execution or while preparing the wellbore for production. So in this case you may choose to give up some completion and stimulation control in order to minimize operational problems and project costs. Additionally, some stress environments just aren't suited for casing and cement. If the stress environment will result in an elevated breakdown pressure that exceeds casing capabilities, you probably would want to consider an alternative completion technique. After all, there is nothing worse than spending millions of dollars drilling a horizontal well and not being able to breakdown the formation and pump the planned fracture stimulations.

Thus, the completion philosophy should be based on the best control that can be achieved within the limits of the reservoir objectives and the geomechanics of the target, with the understanding that just because you want to have fractures every 10 feet down the lateral doesn't mean you will be able to achieve it. In any battle between our reservoir objectives and geomechanics, the state of stress wins every time and the cost of the battle can be excessive.

We have post-appraised several of these battles where horizontal wells were drilled in naturally fissured reservoirs. The wells were drilled to cross the natural fissures, image logs were run to identify where the fissures were, and completions were planned in the intervals with the greatest density of natural fissures. As you read this paragraph, review Figure 14 again. As Figure 14 indicates, the treating pressure was proportional to the density of the natural fissures such that the intervals with dense fissures could not be stimulated because of excessive treating pressures (treatments pressured out) and the intervals without natural fissures could be treated without any issues and at low treating pressures.

Finally, there are several methods of achieving positive isolation in cased and cemented horizontal wells that have been utilized for many years. In the North Sea, Maersk utilized completion tools (PSI) to perforate, stimulate, and isolate horizontal wells while Amoco (now BP) used sand plugs with coil tubing clean-outs to achieve similar results. More recently in the Barnett Formation, cased and cemented horizontal wellbores with pumpdown plugs for isolation are being used efficiently and effectively.

Many open hole horizontal wellbores utilize external casing packers (Packers Plus and Frac Point) to exert some, albeit limited, control over the completion and stimulation staging. Swellable packers and chemical packers have been developed to improve the control in horizontal well completions with some success.

Some operators choose what I would call "Pump and Pray," the open hole completion method whereby attempts are made to divert the stimulation with proppant concentration and size, fluid type, ball sealers, etc. In some areas, these techniques are used successfully, while many datasets suggest suboptimal completions and stimulations are the result of this technique being used in other areas.

Horizontal Well Fracturing- Basis of Design:

The basis of fracture design is a critical design parameter for multiple fractured wells. As shown previously, to achieve horizontal well objectives in tight and unconventional gas reservoirs you need to achieve as long a fracture as possible. The basis of fracture design requires an understanding of the in-situ stress profile, Young's Modulus, and leak-off coefficient with depth. Many papers[30-36] have documented the process of developing the basis of design and we won't belabor it here. However, several key points will be discussed.

One such point is that the basis of design should be developed utilizing vertical or near vertical well data. As noted previously, the geomechanical stress state can influence pressure data in horizontal wells making it difficult to assess. In addition, log and other data collected in horizontal wells do not provide the broad spectrum of information needed for fracture design and execution. Once a design basis is established, data collected in horizontal wells can be used to "validate" the design assumptions when coupled with other diagnostic methodologies such as micro-seismic imaging.

Another point is that micro-seismic mapping has proven to be a valuable completion assessment tool in horizontal well completions, especially in completions where limited to no completion control is excercised. As a result, it is highly recommended that a micro-seismic monitoring program be established as early in the horizontal well program as possible to ensure that the completion and stimulation objectives are being achieved.

Horizontal Well Risks and Mitigation Strategies:

The objective of horizontal wells in tight formation and unconventional gas reservoirs is to improve the gas production rate and rate of recovery just as it is in vertical wells. However, the completion and well stimulation(s) in horizontal wells is far more complex. The role of this section is to identify some of these risks and pose risk mitigation strategies to aid in the successful horizontal well completion and stimulation. The subsequent paragraphs will detail and document these risks and mitigation strategies. First, the most common and potentially devastating risk is that of poor wellbore-fracture communication.

Wellbore-Fracture Communication (Tortuosity/ Near Wellbore Pressure Loss)

Fracture tortuosity, or Near Wellbore Pressure Loss (NWBPL), can be a serious obstacle to successful proppant placement in hydraulic fracture stimulations in vertical wells but is far more critical and common to proppant placement in horizontal wells[37-40]. NWBPL is a friction pressure drop in the near wellbore region that inversely measures the quality of the communication between the wellbore and the fracture. If no downhole friction is present, the wellbore-fracture communication is excellent. However, as the down hole friction gets larger, the wellbore-fracture communication gets worse.

Fracture stimulations in the Cooper Basin of Australia[41] highlight the fact that in vertical wells in the Cooper Basin, 90% of the fracture stimulations were pumped to completion (i.e. defined as in excess of 80% of the planned proppant placed). Ten percent of the treatments failed to place at least 80 percent of the proppant. In these wells, high levels of Near Wellbore Pressure Loss were seen. For example, in these wells, when an excess of 600 psi of NWBPL was seen the jobs could not be pumped to completion. This paper identified four main types of tortuosity in vertical wells. These are (1) Fracture Turning (one plane movement), (2) Fracture Twisting (two plane movement), (3) Multiple Fractures, and (4) Fracture Migration (high stress to low stress).

Applying the Cooper Basin vertical well types of tortuosity to horizontal well applications shows that Fracture Turning (Type 1) is created by a fracture initiation through perforations that are not aligned with the principal stress directions. As discussed previously, this occurs in a normal stress environment where $\sigma_v > \sigma_{Hmax} > \sigma_{hmin}$ and where the perforations were not in the top and bottom of the wellbore (i.e. theta 0 and 180 degrees where the breakdown pressure is the lowest). This type of tortuosity is unlikely with any type of open hole completion.

Fracture Twisting (Type 2) occurs when a fracture realigns itself in a favorable direction by movement in two planes. This type of tortuosity may occur in stress regimes where the near wellbore fracture component is vertical due to hoop stresses but realigns itself in a non vertical plane away from the wellbore. This “complex” fracture behavior may be quite common in horizontal wells that haven’t been broken down and where the hoop stresses dominate the early fracture initiation/propagation direction prior to realigning with the principal stresses. These tortuous effects should once again be minimized in open hole completions where the fracture is allowed to initiate in any direction; however, it needs to be understood that the well azimuth plays a strong role in this type of tortuosity.

Multiple Fracturing (Type 3) can occur in low deviatoric stress regimes and in the presence of natural rock flaws and fissures. Extremely high levels of tortuosity can result from this type of tortuosity, as multiple fractures in close proximity can effectively increase the Young’s Modulus, treating pressure, and narrow fracture widths as shown in the geomechanical section of Fracture Interference. This type of tortuosity may be quite common in open hole completions but should be easily mitigated in cased, cemented, and perforated wellbores by limiting the length of the perforation intervals. Further, one indicator of this type of tortuosity may be evident from treatment data as it is likely to show up as anomalous pressure effects with proppant addition.

The fourth type of tortuosity is Fracture Migration (Type 4), which can be caused by the initiated fracture migrating from a high stress interval to a low stress interval. This type of tortuosity can occur in highly tectonic environments where the imposed strain is excessive. Fracture Migration, for the most part, should be controllable simply by carefully selecting the location to drill the horizontal well. In most basins, the higher stress lithologies tend to be the shale formations. Therefore, caution should be taken to ensure that as much of the lateral as possible is drilled in the productive horizon rather than in the shales. In shale formations, horizontal wells should be placed in the shale intervals with the lowest stress to minimize or mitigate the migration of the fracture. Similarly, many horizontal wells are being drilled in relatively thin sands where it is difficult keeping the well trajectory within the target sand. Such problems can occur even in thick sands. If the well trajectory is going in and out of the target sand or in and out of the bounding shales and siltstones, it can be difficult to place the completion and fracture stimulation where it was intended. It should be noted, however, that if the stress contrast between the target formation and bounding beds is minimal, the completion and fracture stimulation may not be compromised. On the other hand, if the in-situ stress contrast is large, it might be quite difficult to complete and fracture stimulate the well. This may the case if, for example, the stress contrast between the target sand and bounding shale is large (i.e. Arkoma Basin) and the completion is to be made in the shale interval. There is little likelihood of pumping the fracture stimulation to completion, as the shale will act as a choke, limiting the injection rate and fracture width and potentially impacting the ability to place sand.

Horizontal Well Deliquification

Horizontal well deliquification is a difficult topic to discuss for several reasons. First, in most reservoirs, deliquification is a late(r) well life issue, and fractured horizontal well performance should result in well performance far and away sufficient to unload any gas well. As a result, not a lot of field experience exists around deliquifying horizontal wells. Second, many of the fractured horizontal wells where multi-phase flow has been encountered and extensive production experience developed are oil reservoirs. Dealing with multi-phase flow in horizontal wells may/likely will be different in an oil well than in a tight formation gas well.

In most oil well applications, horizontal wells are drilled horizontal (90^o) to toe up (90^o+). This wellbore configuration allows the fluids to collect near the heel where they can more readily be lifted or pumped to the surface. In tight formation gas wells the only published data is from the Permain Basin[18], and it suggests that drilling horizontals toe up or toe down both underperform drilling a truly horizontal well due to liquid loading effects. Perhaps this is the result of wellbore porpoising, thereby creating P-Traps in the borehole for fluid to collect and inhibit gas flow.

Basis of Fracture Stimulation Design

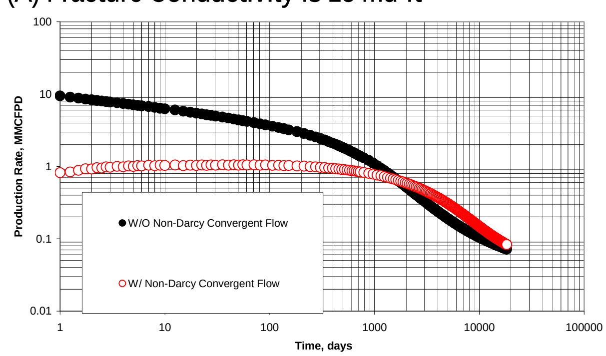
A large part of this document has been devoted to the importance of creating fracture length and the need to develop the basis of design for fracture stimulating horizontal wells. However, it should be noted that this BOD work is much easier, more straightforward, and cheaper if done in vertical wells prior to attempting a horizontal well completion and stimulation. Conducting micro-fracture tests (i.e. determining closure stress) in horizontal wells is much more difficult than in vertical wells due to the radial and not rectangular application of the principal stresses and the difficulty in establishing good wellbore-fracture communication, as discussed previously. Once these issues are resolved, initiating and propagating a fracture in a horizontal well is still a function of the geomechanical dataset (in-situ stress, Young's Modulus, and leak-off coefficient profile with depth). Always develop the geomechanical profile with depth from analyses of vertical well datasets and apply these results to the horizontal well completion and stimulation.

Economic Risk Considerations

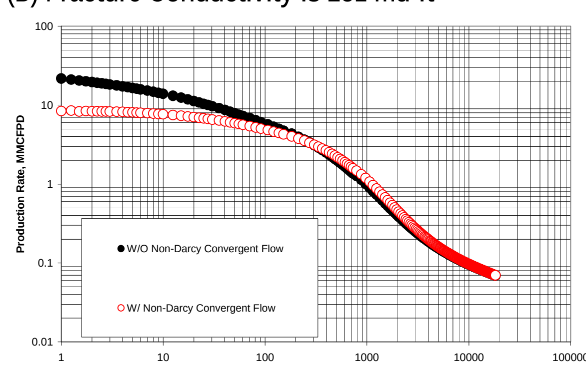
In tight formation gas reservoirs where completion and fracture stimulation are unrisked, transverse horizontal wells with multiple fractures will always be deemed more attractive than (single or multiple fractured) longitudinal wells. This is easy to appreciate since the multiple fractured transverse horizontal well is increasing the drainage area and contacting greater reserves than the longitudinal well, which is simply acting as a well with a greater fracture half- length. Transverse horizontal wells will "always" have greater drilling completion and stimulation risk than longitudinal horizontal wells, and this increased risk should be considered prior to developing a horizontal well program in any tight formation gas basin. Further, if long fractures cannot be created in a particular formation for geomechanical reasons, for example, the application of multiple fractured transverse horizontal wells to the project will not only entail greater risk but will do so with few of the inherent benefits (i.e. reserve recovery is directly related to the dimensions of the transverse fractures). Always do a risk assessment prior to developing and implementing any horizontal well program. Also note, the well performance of a longitudinal horizontal well may not meet the recovery/economic objectives set forth for the project even if the completions and stimulation(s) are successful. In such a case, a multiple fractured transverse horizontal well should be considered. However, do so recognizing the increased risk of execution failure and ensure all mitigation strategies for these risks are implemented.

Figure 15: Convergent and Non-Darcy Flow Effects

(A) Fracture Conductivity is 28 md-ft



(B) Fracture Conductivity is 281 md-ft



Convergent Non-Darcy Flow Considerations

Convergent and Non-Darcy Flow can dramatically impact horizontal well performance early in the life of the well and can therefore have a significant and detrimental effect on project economics. These effects occur during transient flow and can be mitigated by increasing the near wellbore conductivity or increasing the number of fractures placed (reducing transient flow time). Interestingly, in vertical tight and unconventional gas wells neither convergent flow nor Non-Darcy flow is a problem[42] unless the well is experiencing multi-phase flow. However, in transversely fractured horizontal wells, convergent Non-Darcy Flow can be quite significant.

Figure 15 shows two plots of production rate versus time for a simulated tight gas horizontal well (permeability of 0.01 md). Each figure compares the simulated production with and without convergent and Non-Darcy Flow being considered. Figure 15A is for a fracture with 28 mdft of conductivity while Figure 15B is for a fracture with ten times the conductivity (281 mdft). For the low conductivity case in Figure 15A, note that the early time productivity is flat at 1 MMCFPD for nearly four years as compared to the case where Non-Darcy Flow Effects are not considered. Also note that when the conductivity is increased that the effect of Non-Darcy Flow is diminished both in magnitude and duration.

Case Study- Arkoma Basin:

Geology:

The Arkoma Basin located in eastern Oklahoma and western Arkansas is one of the most prolific gas producing areas in the United States. The basin extends for approximately 260 miles in a predominately east-west direction and is 20 to 50 miles wide from north to south. The basin is bounded on the south by the Ouachita overthrust belt, and on the north by the Ozark uplift. Given the structural complexity of these bounding features, the basin has undergone extreme folding and faulting which resulted in a sequence of east to west trending anticlines and synclines throughout the basin.

Most of the gas production from the basin is associated with anticlinal or fault-trap structures where sufficient effective porosity was developed and preserved. Currently, more than 30 gas producing horizons have been discovered and produce; these range in age from early Pennsylvanian to the Cambrian-Ordovician. The primary horizon of interest in this case study is the Pennsylvanian age Atokan sands, locally called the Red Oak Formation[43-45].

The Red Oak Gas Field was discovered in 1960. Production is extremely dry gas found between 7,000 to 10,000 feet.

Reservoir Characteristics:

The Red Oak Formation in the Red Oak Gas Field exhibits porosities from as low as five percent to well in excess of ten percent. The best porosity development includes intergranular porosity with well connected dissolution porosity. This reservoir type generally has porosities in excess of ten percent and permeability well in excess of 0.1 md. The poorer quality sands have considerably less intergranular porosity and more dissolution porosity and microporosity. Precipitates of authigenic clay minerals and quartz overgrowths result in small pores and higher water saturations. These sands have porosities of five to ten percent and permeabilities on the order of 0.01 to 0.10 md. The poorest quality sands are characterized by predominately dissolution porosity and have extremely low porosities and permeabilities. These sands have porosities less than five percent and permeability on the order of 0.001 md.

Another key reservoir characteristic of the Atokan sands in the Red Oak Gas Field in the Arkoma Basin is seen in net sand thickness. Net pay ranges from as little as fifty feet to as much as two hundred feet of net pay.

Geomechanical Considerations:

As mentioned, the Arkoma Basin is bounded on the south by the Ouachita overthrust belt and to the north by the Ozark uplift. These paleo-tectonic features have had a major impact on the state of stress in the Arkoma Basin. The current day stress state in the basin has been projected to be a transitional Normal to Strike-Slip fault environment based on a review of breakouts, leak-off tests, and mud weight data. This assessment would imply that the maximum horizontal stress was on the order of or larger than the vertical stress in the Red Oak Field. It should be noted that this evaluation would appear reasonable, as breakouts were evident in detailed caliper log analysis and such features are an indication of a large difference between the horizontal stresses.

To evaluate this assessment, a review was undertaken utilizing log and fracturing data from the Red Oak Field area. In preparation for the horizontal well program, an extensive fracture data collection program utilizing bottom hole pressure gauges was instituted. This data was used in this evaluation.

First, a density log was integrated to determine the overburden or vertical stress to be 1.11 psi/ft. Pump-in data from ten mini-frac tests (with bottom hole pressure gauges) were reviewed and an average closure pressure (minimum horizontal stress) of 5,149 psi was determined at an average depth of 8,157

Table 2: Breakdown Pressure Analysis

Well ID	***BD Pressure psi***	***σ_{hmin} psi***	***BD/σ_{hmin} Ratio***
1	5860	5360	1.093
2	5636	4736	1.190
3	5249	5159	1.017
4	6059	5059	1.198
5	5515	5366	1.028
6	5930	4989	1.189
7	6150	5550	1.108
8	5395	5195	1.038
9	5224	4634	1.127
Avg	***5669***	***5116***	***1.108***

feet (0.631 psi/ft). Further review of the data showed an average breakdown pressure of 5,708 psi (0.700 psi/ft). As previously noted, when the horizontal stresses are similar the breakdown pressure is elevated, and when there is a large difference between the horizontal stresses the breakdown pressures are low. Thus, a review of the ratio of breakdown to the minimum horizontal stress can be utilized to infer the maximum horizontal stress. In this Arkoma Basin example, the average ratio of the breakdown pressure to minimum horizontal stress is small at 1.108. This would imply that there is a large difference in the maximum and minimum horizontal stresses. Table 2 summarizes the data used in this evaluation.

Next, we used the breakdown pressure program with the Arkoma Basin data to determine an estimate of the maximum horizontal stress. Based on this analysis, assuming a reservoir pressure of 2,500 psi (0.306 psi/ft), Poisson's Ratio of 0.20, a tensile stress of 300 psi, and a Biot's Constant of 1.0, an estimate of the maximum horizontal stress of 7,540 psi (0.924 psi/ft) was made. Thus, this analysis supports the review of drilling data which suggested a large difference in the horizontal stresses (nearly 2,400 psi). However, the maximum horizontal stress is clearly less than the vertical stress, suggesting a normal fault stress environment. It should be noted that average values were used in this evaluation. By assessing the minimum (1.017) and maximum (1.198) breakdown pressure to minimum horizontal stress ratio (from Table 2), a range of estimates of the maximum horizontal stress was developed. This assessment suggested a maximum horizontal stress between 6,920 psi and 7,985 psi.

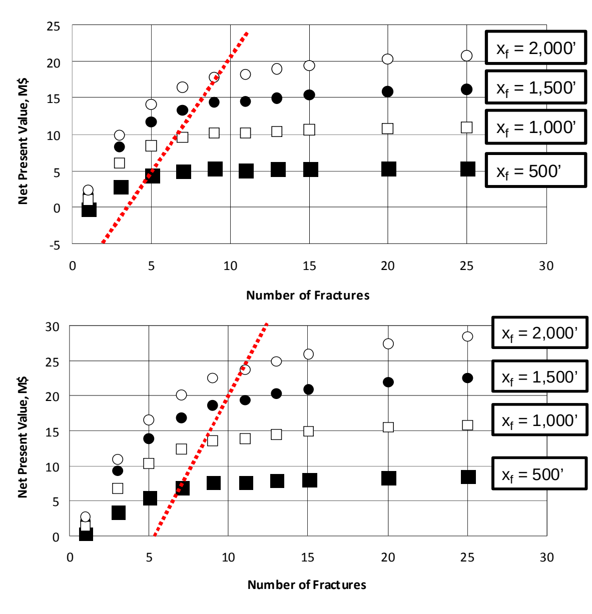
This analysis of pump-in data clearly shows that even with the lowest estimate of maximum horizontal stress that there is a large difference between the horizontal stresses (1,776 psi) and with the highest estimate of maximum horizontal stress the fault environment is still normal as the overburden stress (maximum principal stress in a normal fault environment) is over 2,400 psi greater than the maximum horizontal stress.

Objectives-Optimization Study:

The objective of horizontal wells in the Red Oak Formation is to improve the gas production rate, rate of recovery, and project economics, just as it is in vertical wells. An optimization study was conducted for the Red Oak Gas Field. Results of this study are shown as Figure 16, plots of Net Present Value versus Number of Fractures for varied fracture half-lengths. The top plot is for a 2,000 foot lateral and the bottom plot is for a 3,000 foot lateral. As shown, for a 2,000 foot lateral, the optimum number of completions for this reservoir is 5 to 9 for the anticipated fracture half-length of 500 to 2,000 feet. For a 3,000 foot lateral, the optimum number of completions/fractures is 7 to 11. Therefore, the optimum interfracture spacing is on the order of 250 to 500 feet depending on the achieved fracture dimensions.

Also note that although a fracture half-length of 1,000 to 1,500 feet is anticipated, the fracture objectives are to generate the longest fractures possible while maintaining the completion and operational integrity.

Figure 16: Horizontal Well Optimization



Completion Plan:

Given the stress environment (normal fault environment with large differences in horizontal stresses), geomechanically anticipated fracture heights well in excess of 200 feet, and the reservoir engineering objectives (fracture every 250 to 500 feet) given the anticipated reservoir permeability of 0.005 to 0.010 md, the completion plan selected was an open hole with external packer system (Packers Plus and Frac Point). Some consideration was given to casing, cement, and perforating, but this completion plan was considered more expensive and potentially less efficient (initially, at least).

Initial problems were encountered drilling and placing the horizontals in the Red Oak sands, which led to problems getting the completion system to the toe of the well. Modifications were made to drill bits and the MWD program, which allowed the horizontals to be placed as desired and ultimately allowed the completion system to be placed as well. This issue seriously impacted the first well in the program but was quickly recognized and resolved and became a minor issue as the program progressed.

Basis of Fracture Design:

The basis of fracture design (BOD) was developed in vertical wells prior to initiating the horizontal well program. A ten vertical well data collection program was initiated throughout the field. This program included Fracture Efficiency Tests (FET) and mini-fracs with bottom hole pressure gauges to aid the development of a geomechanical profile with depth of in-situ stress, Young's Modulus, and leak-off coefficient. Additionally, micro-seismic mapping was utilized to calibrate the fracture stimulation dataset inferred from the pressure data. The coupling of micro-seismic mapping with treating pressure analysis is a valuable tool in developing the basis of design, as the micro-seismic data provides an estimate of the fracture dimensions while the net treating pressure data provides information regarding the material balance of the fracture system. The details of this analysis are not included here; however, the results of this analysis were used in every aspect of the design, implementation, and post-appraisal of the horizontal well development program.

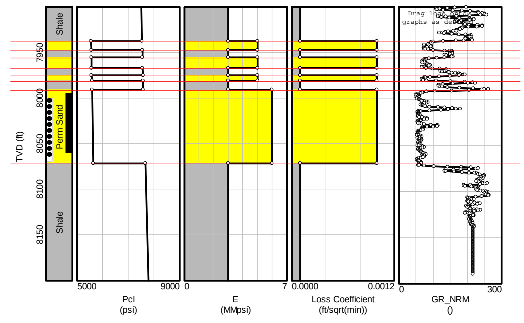


Figure 17: Fracture Geomecanical Profile

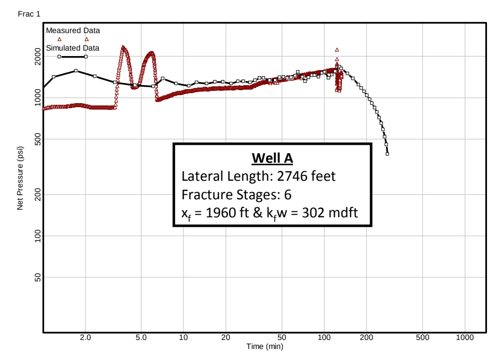


Figure 18: Fracture Net Pressure "History Match"

Post Appraisal of Horizontal Wells:

An ongoing post-appraisal of the Red Oak horizontal well program was conducted while wells were being drilled and completed. Drilling, completion, and stimulation issues were addressed as they occurred. This documentation of results is based on a post-assessment of the first nine horizontal wells drilled and completed in the Red Oak Field. The post-appraisal process consisted of several steps which included:

(1) Loaded near offset vertical well logs, horizontal deviation survey, fracture stimulation, and production data into STIMPLAN for review,

(2) Use Basis of Fracture Design (BOD) to build geomechanical profile with depth,

(3) "History match" horizontal well fracture stages,

(4) Build reservoir model with petrophysical input and horizontal well performance, and

(5) "History match" horizontal well performance.

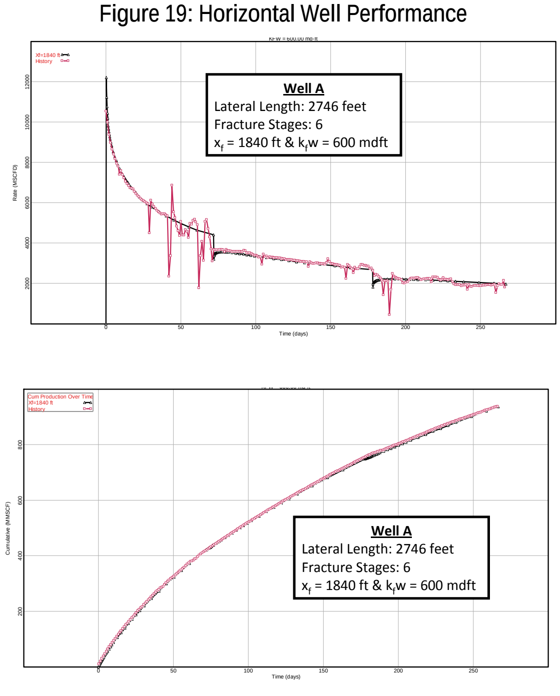


Figure 19: Horizontal Well Performance

Figures 17 and 18 show an example of the process (Steps 1 to 3) being employed in the post appraisal. Figure 17 is the geomechanical profile with depth of in-situ stress, Young's Modulus, and leak-off coefficient derived from prior near offset vertical well data, while Figure 18 shows the fracture history match of one of the horizontal well completion/fracture stimulation stages. As shown, a very good match of the net treating pressure was obtained. This analysis indicated a contained fracture growth (increasing net treating pressure with time) and a fracture half-length of nearly 1,960 feet with 302 mdft of fracture conductivity.

Next, the well performance was history matched with STIMPLAN using the petrophysical input, as shown by process steps 4 and 5. Results of this production history match are shown in Figure 19 as plots of production rate (top) and cumulative production (bottom) with time, respectively. As shown, a good match of the production behavior was obtained with a fracture half-length of 1,840 feet and conductivity of 600 mdft. Thus, the fracture half-length from the production match was within six percent of the fracture match. This approach was utilized with the remaining wells being post-appraised. In nearly all cases, good agreement was seen between the fracture history match and the production history match. Results of this analysis clearly show the effect/importance of lateral length and fracture interference on well performance.

Figure 20 shows plots of the initial potential (top) and 6-month cumulative recovery (bottom) as a function of the distance between completions/fractures. As shown, the optimum distance between completions/fractures is clearly 450 to 550 feet. Interestingly, this is nearly twice the fracture height as determined from the fracture history matching process, confirming the finite element modeling of fracture interference which indicated that if the fractures were closer than twice the fracture height, treating pressures would increase due to interference.

Figure 21 shows a plot of 6-month cumulative recovery versus lateral length and, with the exception of a couple of outliers, clearly shows the importance of lateral length on well recovery. The effect of fracture-half-length was less clear, however, as the wells with the longest fractures tended to be the wells with the lowest reservoir permeability. Variations in fracture half-length showed little correlation with cumulative recovery and well performance. This result is likely due in part to the increases in permeability and pay thickness, which tend to improve well capabilities and leak-off while reducing the achieved fracture dimensions.

Figure 20: The Effect of Interfracture Distance

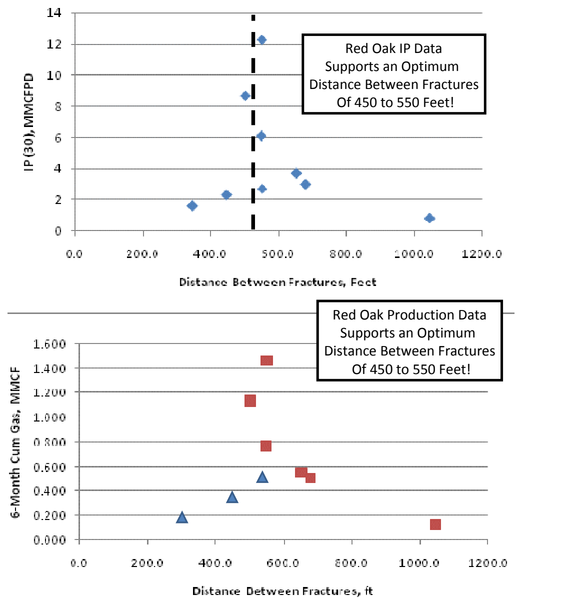
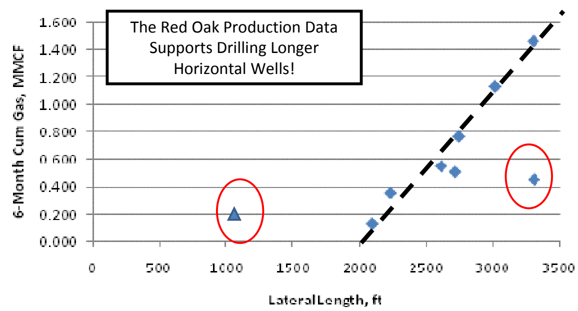


Figure 21: The Effect of Lateral Length



Summary and Conclusions:

This paper clearly shows the importance of linking the stress state and the geomechanics with the objectives of any horizontal well development program. Further, through understanding of the geomechanics and the basis of fracture design from vertical well evaluation, economic optimization studies can be undertaken to align the completion and stimulation plans with the horizontal well objectives. Based on this work, we conclude:

1. Successful horizontal well programs require the integration of petrophysical/reservoir, completion, and fracture stimulation disciplines for success. Design and execution failure in any area will result in a suboptimal horizontal well(s). This is especially true in tight formation and unconventional gas reservoirs.
2. Geomechanics and the state of stress play a large role in horizontal well completion and fracture stimulation success. Failure to consider the geomechanics in any horizontal well completion can have catastrophic results.
3. Stimulation risks and risk mitigation strategies should be reviewed prior to initiating a horizontal well program.

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Nomenclature

σ_v = Vertical stress
σ_{Hmax} = Maximum horizontal stress
σ_{hmin} = Minimum horizontal stress
α = Well azimuth, degrees from maximum horizontal stress
β = Wellbore deviation (0^o is vertical and 90^o is horizontal)
ϕ = Wellbore breakdown location, (0^o and 180^o is top and bottom of the well)
x_f = Fracture half-length in feet
k_fw = Fracture Conductivity in mdft
L = Lateral length in feet
k = Permeability in md

H = Fracture height in feet
E = Young's modulus in psi
E' = Plain strain modulus in psi
Q = Pump rate in BPM
μ = Fracture fluid viscosity in cP
dx = Distance between fractures in feet

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