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# Defining Horizontal Well Objectives In Tight And Unconventional Gas Reservoirs

Britt, L.K., Jones, J.R., and Miller, W.K. II, NSI Fracturing LLC



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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 well planned completion and fracture stimulation(s) to make an economic well. Even in sweet spots in unconventional and tight gas reservoirs good completion and stimulation practices are required to achieve economic success. But 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 this paper.

This paper focuses on some of the key elements of well completions and stimulation practices as they apply to horizontal wells. Economic optimization studies were conducted for tight gas reservoirs highlighting the importance of lateral length, number of fractures, inter-fracture distance, fracture half-length, and fracture conductivity. In addition to the tight gas completion and stimulation considerations, network complexity will also be considered. These results will be used to develop a horizontal well decision tree for evaluating the various drilling, completion, and stimulation issues encountered in horizontal wells in tight and unconventional gas reservoirs. Field examples will be used to highlight these strategies.

This work benefits the petroleum industry 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 geomechanical limitations into a horizontal well completion and stimulation strategy,
4. Developing a horizontal well completion and stimulation decision tree 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 vertical wells in a particular area. Generally, the difficulties encountered are associated with 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. While the application of horizontal well completion and stimulation technology has been successful, it's' use has varied 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]. In tight and unconventional gas reservoirs, greater operational control and reliability are necessary for success and to prevent erosion of project economics. Optimization studies[8-10] of these reservoirs has shown the importance and value of the integration of good horizontal drilling, completion, and well stimulation practices.

This paper focuses on some of the key elements of well completions and stimulation practices as they apply to horizontal wells. Economic optimization study results are presented for tight gas reservoirs highlighting the importance of lateral length, number of fractures, inter-fracture distance, fracture half-length, and fracture conductivity. In addition to the tight gas completion and stimulation considerations, network complexity is also considered.

## Discussion:

Horizontal wells require a well planned completion and fracture stimulation(s) to make an economic well in a tight gas and/or unconventional gas reservoir. But what are the objectives of horizontal wells and how do we relate the completion and stimulation(s) to achieving these goals? In order to understand the horizontal well objectives in these reservoirs a simulation study was undertaken and the economics of multiple fractured horizontal wells in tight and unconventional gas considered. Of interest to this evaluation were reservoir, completion, and stimulation parameters. For the reservoir considerations net pay, reservoir pressure, and reservoir permeability were evaluated. For the completion practices completion control was considered, and for the fracture stimulation the effects of fracture length and conductivity were considered in light of fractured horizontal well objectives. Finally, horizontal well drilling, completion, and fracture stimulation costs were considered along with economic parameters to ensure that the horizontal objectives were established for all environments.

First, let's look at horizontal well objectives through the reservoir and production engineering considerations. Well performance and economic objectives should be developed for horizontal wells, highlighting the incremental benefits of various completion and stimulation strategies. Most operators use various metrics to establish the horizontal well objectives. Some utilize economic metrics based on the estimated ultimate recovery and rate of recovery of the horizontal well. Others utilize a well performance/production rate metric to establish the horizontal well objectives. Such a metric may include the use of Instantaneous Potential, IP, at 30 days or the use of an annualized first year rate. The IP metric is perhaps more common given that it doesn't require an estimate or prediction of future well performance. However, the use of IP as a metric doesn't consider costs and therefore may drive the optimization more towards completions/fractures.

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 | $\phi$ | *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 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.

## Recoverable Reserve Considerations:

It should be fairly obvious that the more recoverable reserves there are the greater number of completions and fractures are required to optimally deplete the reservoir and recover these reserves. Based on our previous discussion the effect of net pay should be fairly obvious; however, the effect of the number of completionsfractures on recovery may not be that obvious. To show this effect let's look at Figures 1 to 3 which highlight the economic benefits, Initial Potential, and Annualized First Year Rate as a function of the Number of Completions, respectively.

**Figure 1: Economic Effect of Recoverable Reserves (Net Pay)**

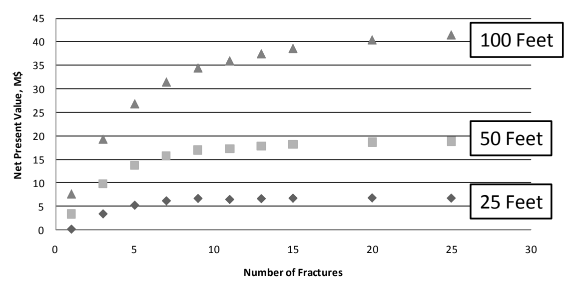



Figure 1 shows a plot of net present value as a function of the number of completions comparing a reservoir with 25, 50, and 100 feet of net pay. As shown, for a reservoir with limited net pay (25 feet) the number of completions/fractures required to optimally deplete the reservoir is five completions. Beyond 5 there is little to no economic benefit from increasing the number of fractures. For a reservoir with 50 and 100 foot net pay thickness the economic optimum number of completions is 9 and 20, respectively. Thus, the greater the amount of recoverable gas the more completions are needed to optimally recover these reserves. Also note that doubling the net pay in this example tripled the economic value and by quadrupaling the net pay to 100 feet resulted in an eight fold increase in the discounted net present value.

Next, let's look at the Instantaneous Potential, IP, or 30 day rate for these three cases. Figure 2 shows a plot of Instantaneous Potential versus Number of Fractures for net pay of 25, 50, and 100 feet. As shown, for each case from 25 to 100 feet of net pay, the initial potential increases linearly with the number of fractures up to 15 completions/fractures. Beyond fifteen, however, the Instantaneous Potential is no longer linear indicating that the fractures were interfering within 30 days.

Figure 3 shows a plot of Annualized First Year Rate versus the Number of Fractures. This figure indicates that the annualized first year rate is linear for the three cases (i.e, 25, 50, and 100 feet) up to eleven fractures. Beyond this point (i.e, eleven fractures) the interfracture distance is such that interference is seen within 365 days. Comparison of these three figures is interesting as it shows that the use of IP and annualized first year rate for that matter have little to do with the optimum economics of a multiple fractured horizontal well in a tight gas reservoir. For example, the 25 foot net pay example shows that the IP is linear to 15 fractures, however, the economic optimum is achieved with just five fractures. On the other hand, the 100 foot net pay case shows that the IP is linear to 15 fractures but the economic optimum is achieved at 20 fractures.

Figure 4 shows a plot of the Net Present Value versus the Number of Fractures for various reservoir pressures. As shown, once again the optimum number of fractures from an economic standpoint increases as the recoverable reserves (expressed through pressure) increases. For example, the optimum number of fractures for the 1,000 to 3,000 psi pressure cases is 7, 15, and 20, respectively. Once again, the more recoverable reserves the greater the optimum number of fractures.

Figure 5 shows a plot of the Annualized First Year Rate versus the Number of Fractures for reservoir pressures of 1,000 to 3,000 psi. As shown, regardless of the reservoir pressure the annualized first year rate is linear up to eleven fractures. Thus, once again the incremental production rate per fracture has little to do with the economic optimum number of fractures.

It should be noted that Figures 3 and 5 regardless of net pay thickness or reservoir pressure all indicated that the annualized first year rate was linear up to eleven fractures for this 3,000 foot lateral. Beyond eleven completions and fracture stimulations the annualized first year rate per fracture declined. Similarly, although not shown, the IP declined once the number of fractures exceeded 15 for all net pay and

**Figure 2: IP Effect of Recoverable Reserves (Net Pay)**

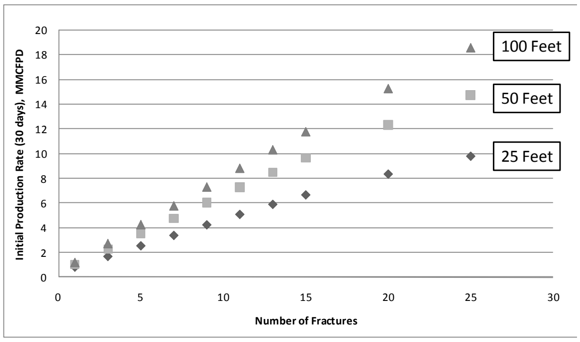



**Figure 3: Annualized Rate Effect of Recoverable Reserves (Net Pay)**

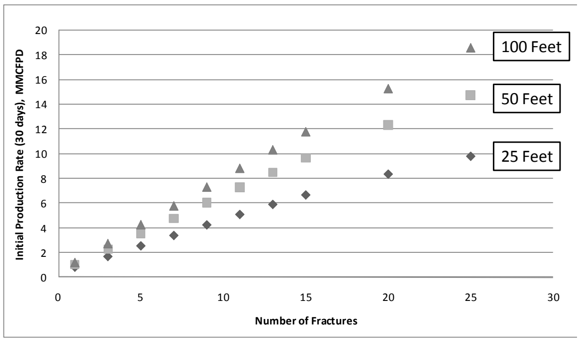



**Figure 4: Economic Effect of Recoverable Reserves (Pressure)**

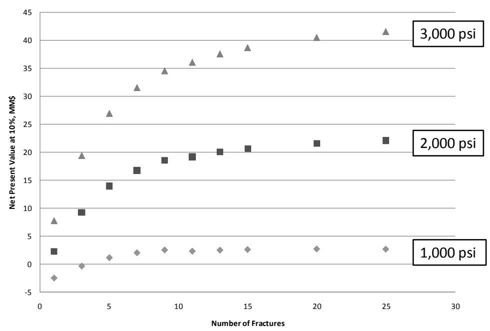
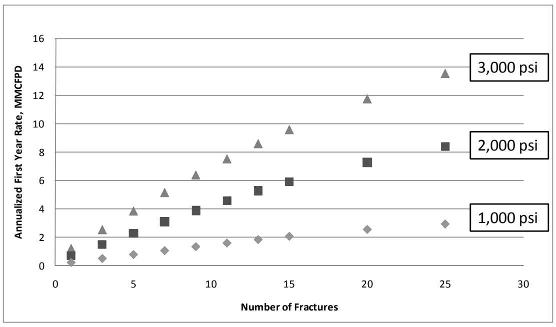



**Figure 5: Annualized Rate Effect of Recoverable Reserves (Pressure)**

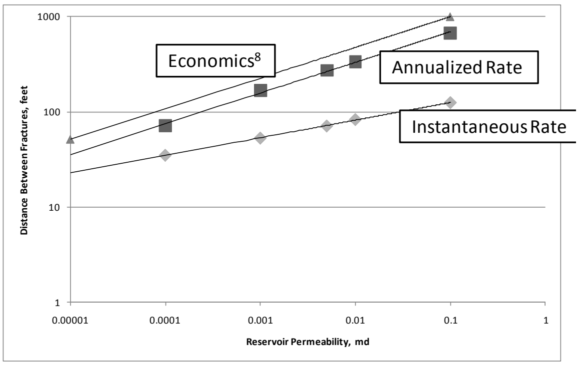


reservoir pressure cases. Interestingly, the economics are obviously affected by net pay and reservoir pressure as is the magnitude of the production rate, however, the incremental production rate is affected more dramatically by reservoir permeability.

## Permeability Considerations:

This finding may not be of interest in tight gas reservoirs where permeability can be readily determined with a Fracture Impulse Test (FIT) but in Unconventional Gas Reservoirs where permeability estimates have been derived from mostly laboratory tests that vary by several orders of magnitude it may have great value. For example, consider a multiple fractured horizontal well in a 0.001 md reservoir that has a linear trend of IP (30 day rate) for fractures that are 50 feet apart but a smaller incremental IP per fracture when the fractures are 70 feet apart. A similar effect can be gleaned from an analysis of the the annualized first year rate although much more data would be required. Figure 6 shows a plot of the distance between fractures versus the reservoir permeability for Annualized First Year Rate and Instantaneous Potential.

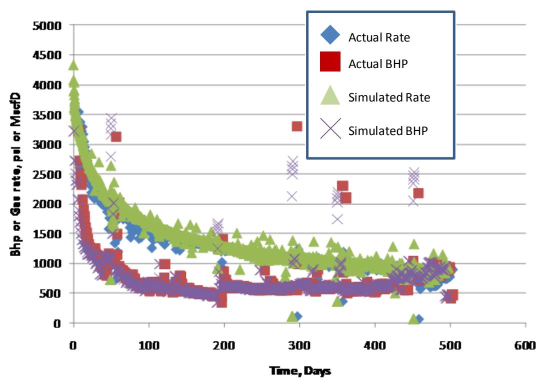
Figure 6: Interference Effect as a Function of Permeability




This figure highlights the interfracture distance as a function of permeability. Although possible to evaluate this in a single multiple fractured horizontal well it would be difficult, timely, and expensive and, therefore, is more likely a benefit to the evaluation of a large horizontal well dataset rather than in a single horizontal well. Also shown, is a trendline for an economic optimization study[8] conducted and presented previously. However, whereas the interference effect on the annualized rate and IP are primarily driven by permeability the economics are affected to a larger degree by net pay and reservoir pressure as indicated previously.

One final thought regarding the effects of permeability in unconventional gas reservoirs. The perception of what is required to make a productive shale completion is heavily biased by a picture of the successful Barnett shale completion that has developed over the last decade[12-22]. In this picture, complex multi-scale fracturing is seen as required to make a good well. These complex fractures are either induced by the massive size of the stimulation or are the result of dilation and reopening of existing fractures or flaws in the rock with water. However, a number of other shale plays the micro-seismic results often support the idea that the predominate fracture pattern created is just a group of fairly long, induced, transverse fractures. Detailed simulations using simpler multiple transverse fractured horizontal wells can be used to match the extended performance data (i.e, the prediction of measeured daily rates with fixed wellhead pressure control). For the cases in our experience, no overprint of complex fracturing appears to be required even though effective permeabilities remain inside the range of expected values from core measurements. Even in the Barnett Shale Play when complex fracture systems are simulated they often include induced transverse fractures of finite and low conductivity and complex fissures of extremely low conductivity[21-24]. Figure 7 shows a plot of of a production history match from an unconventional shale gas well where the actual multiple fractured horizontal well performance was history matched with

Figure 7: Unconventional Gas Well History Match



a matrix permeability of 8 x $10^{-5}$ md (i.e, matrix permeability less than that derived from core analysis) and induced fracture parameters derived from evaluation of each stage of the completion. As shown, an excellent match of the well performance (rate and pressure) was achieved without considering any fissure or "system" complexity. This history match is consistant with the analysis of many other unconventional shale gas wells throughout the North America where even if system complexity is used in the modeling the fissure conductivity used is extremely low in order to diminish its contribution to the well performance. Such findings are consistent with laboratory derived conductivities of un-propped fractures in tight gas and unconventional shale gas reservoirs[25-27].

## Lateral And Fracture Length Considerations:

Figure 8: Economic Effect of Lateral Length

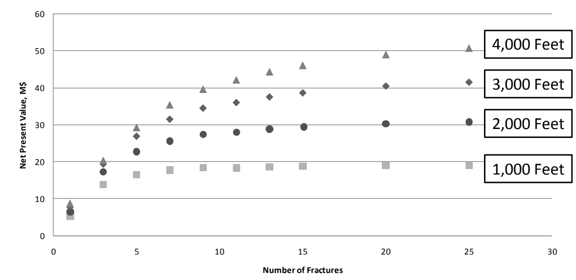
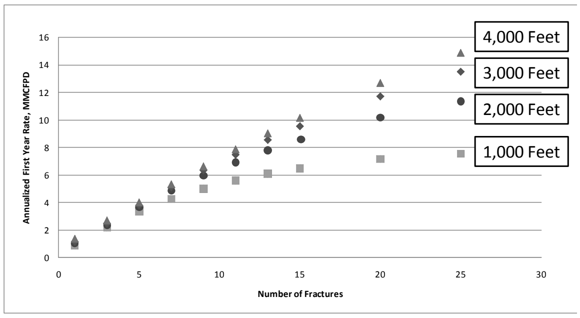


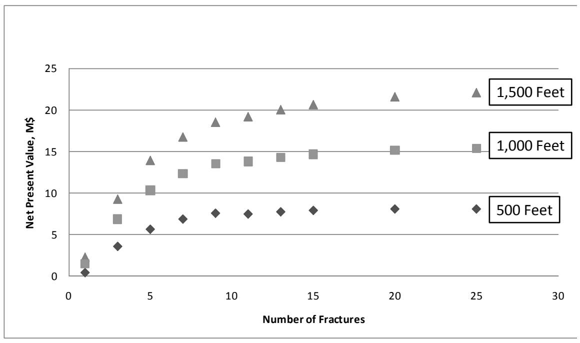

Figure 9: Annualized Rate Effect of Lateral Length




Next, the effects of lateral length and fracture length were investigated. Figure 8 and 9 shows plots of Net Present Value and Annualized First Year Rate versus the Number of Fractures for lateral lengths from 1,000 to 4,000 feet, respectively. As shown, as the lateral length increases so do the optimum number of fractures required to drain the reservoir. Also note that the longer the lateral a greater number of fractures is required before fracture interference is seen in the annualized first year rate (Figure 9). Also note that although the number of fractures for each lateral length is different that the interfracture distance at which the annualized first year rate sees interference is at approximately 300 feet.

Figure 10 and 11 show plots of Net Present Value and Annualized First Year Rate as a function of the Number of Fractures. As shown in Figure 10 the economics are significantly affected by increasing fracture half-length while the fracture half-length has an effect on the optimum number of fractures required to optimally drain the reservoir as well. Again, anything that increases the recoverable reserves increases the number of fractures required to optimally drain the reservoir. Figure 11 shows the effect of fracture half-length on the annualized first year rate. As shown, the fracture half-length has little effect on the interference of the annualized rate (i.e, the departure from the linear trend of the annualized first year rate occurs at a similar number of fractures).

Figure 10: Economic Effect of Fracture-Half Length

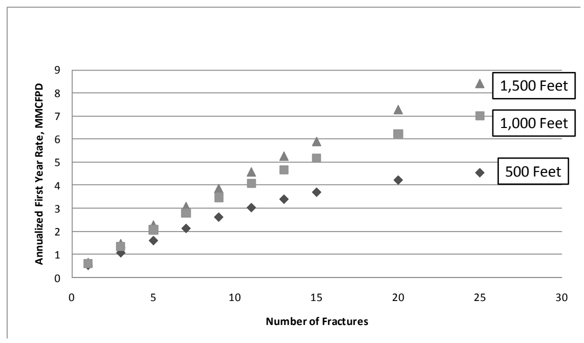



What about the affects of horizontal well orientation? When is it best to drill a longitudinal horizontal well in a tight or unconventional gas reservoir? Unrisked the answer to this question is always never as a multiple transverse fractured horizontal wells will always outperform a longitudinal horizontal well. There are times when a longitudinal horizontal well should and will outperform a failed multiple fractured transverse horizontal well. These times generally occur when fracture length is unachievable and when reservoir permeability is higher.

## Completion Considerations:

As a general rule in horizontal wells the optimum completion design allows the stimulation engineer to exact complete control over the fracture stimulation conducted for each stage. The preceding economic analysis assumed that an external casing packer system was utilized to complete and fracture stimulate the horizontal well. Such a system is common in tight gas reservoirs where the number of fractures to optimally deplete the reservoir is not excessive. However, in lower permeability unconventional shale gas reservoirs many more completions and fracture stimulations are desired. In this application more control than what can generally be delivered by these external packer systems is desired. As a result, the lower the permeability of the reservoir the more desireable the pump down systems become. Ultimately, the selection of which completion system to use depends on a combination of two competing objectives established by the reservoir permeability and the geomechanics. Generally, the reservoir objective for a horizontal well drives the completion design to more stages and closer interfracture distances while the geomechanics tend to limit the number of fractures to roughly twice the fracture height[24]. This work showed that when two fractures are propagating within two times the height of the fractures that treating pressure goes up and fracture width is detrimentally impacted. Beyond twice the height, the fractures propagate with little effect on each other. As they get closer together, however, treating pressure increases, fracture width declines and the risk of treatment execution failure increases. Thus, our reservoir understanding establishes what we would like to achieve but the geomechanics determine what we ultimately can achieve.

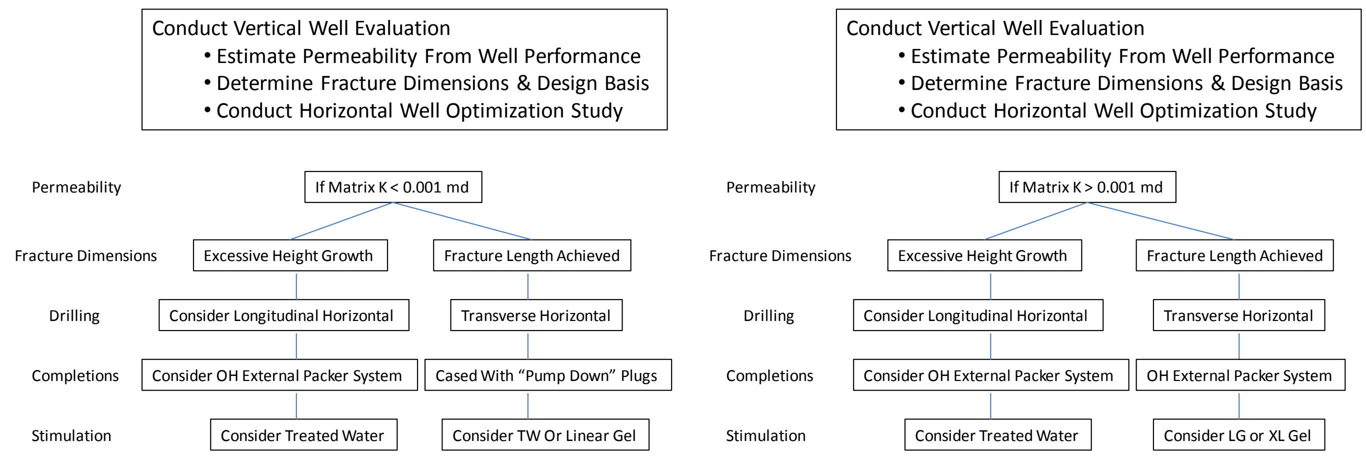
**Figure 11: Annualized Rate Effect of Fracture-Half Length**




## Completion and Stimulation Decision Tree:

One of the objectives of this study was to develop a horizontal well decision tree. However, after working the horizontal well objectives for awhile the authors realized that as with most things in petroleum engineering and especially with completions and well stimulation there just aren't any rules of thumb. Moreover, some level of data collection and reservoir understanding is required in order to establish reasonable and achievable objectives of the horizontal well project. Therefore, we focused on the data collection needs and if such a dataset can be obtained, reviewed, and optimized then a fairly straight forward decision tree can and was developed. Table 2 shows the resulting decision tree that was developed based on our data collection scheme.

**Table 2: Horizontal Well Decision Tree**



As shown, the data collection plan is based on collecting data in vertical wells. The reason for this is that much of the data we use to evaluate the well is a pressure measurement.

Pressure is an inferred measurement even in vertical wells but in horizontal wells it is likely a poor measure of performance. For this reason the authors suggest collecting and evaluating data from a vertical well(s).

If offset vertical well logs, performance data, and fracturing data is available; the engineer should be able to estimate permeability, determine the fracture dimensions being achieved, and more importantly develop a basis of fracture design for the horizontal well and conduct a horizontal well fracture optimization study to establish project objectives for the horizontal well. In unconventional shale gas wells in many areas there are very few vertical wells. Even in these areas the authors strongly recommend that the time and expense to drill a vertical pilot hole be undertaken to log, collect core, and even conduct pump-in decline tests to establish permeability, in-situ stresses, and potentially an estimate of fracture fluid leak-off. Having established this dataset the horizontal decision matrix or decision tree becomes pretty straight forward provided we choose a metric as the basis for establishing the objectives. In this case we have chosen the metric of Initial Potential.

As described in the prior sections of this paper one of the most important parameters to establishing horizontal well objectives is permeability. For example and shown in Table 2, if the permeability is less than 0.001 md the objectives become fairly clear. The first consideration should be the achievable fracture dimensions. If the basis of design (geomechanical model) suggests excessive fracture height growth (fracture length severely limited) the engineer might want to include a longitudinal horizontal well evaluation in the optimization. Although it is unlikely that a longitudinal horizontal well will achieve project objectives in this low permeability environment it may still prove viable once the other well options are risked. Should the longitudinal well prove viable, the use of open hole external packer systems are indicated due to their increased efficiency and lower cost. Finally, treated water is indicated as the fracturing fluid for this low permeability application.

If the basis of design indicates that fracture length can be achieved then a transverse multiple fractured horizontal well is recommended. Further, due to the low permeability and interfracture distance objective (Figure 6) of 30 to 60 feet the use of pump down guns and plugs is recommended to manage the completion and stimulation. Finally, the fracture fluid recommended for this application would be treated water or perhaps linear gel. Optimization work has shown that non-Darcy convergent flow can be important even in reservoirs with permeability as low as 0.001 md and so a more viscous linear gel with additional proppant transport characteristics may be warranted.

For tight gas reservoirs (i.e, permeability in excess of 0.001 md) where the optimum number of completions tends to be limited (i.e, less than 10) the use of open hole external packer systems represent the completion technique of choice due to their efficiency and better cost control. For these higher permeability tight gas reservoirs, convergent non-Darcy flow is more likely an issue. As a result, treated water is unlikely to transport the necessary proppant concentration that the well needs to mitigate this effect.

## Summary and Conclusions

1. The horizontal well objectives should be based on the ability or lack of ability to create fracture dimensions.
2. Multiple transverse fractured horizontal wells outperform longitudinal horizontal wells.
3. The optimum number of fractures in a transverse horizontal well is controlled by permeability and fracture interference.
4. Fracture complexity does not appear to be a requirement of production history matching of tight gas and unconventional gas reservoir performance.
5. Completion design is strongly impacted by the geomechanics and ultimately by the fracture height.

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