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What is Stimulated Reservoir Volume (SRV)?

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Abstract

Ultra-low permeability shale reservoirs require a large fracture network to maximize well performance. Microseismic fracture mapping has shown that large fracture networks can be generated in many shale reservoirs. In conventional reservoirs and tight gas sands, single-plane fracture half-length and conductivity are the key drivers for stimulation performance. In shale reservoirs, where complex network structures in multiple planes are created, the concept of a single fracture half-length and conductivity are insufficient to describe stimulation performance. This is the reason for the concept of using stimulated reservoir volume as a correlation parameter for well performance. The size of the created fracture network can be approximated as the 3-D volume (Stimulated Reservoir Volume or SRV) of the microseismic event cloud. This paper briefly illustrates how the Stimulated Reservoir Volume (SRV) can be estimated from microseismic mapping data and is then related to total injected fluid volume and well performance. While the effectively producing network could be smaller by some proportion, it is assumed that created and effective network are directly related. However, SRV is not the only driver of well performance. Fracture spacing and conductivity within a given SRV are just as important and this paper illustrates how both SRV and fracture spacing for a given conductivity can affect production acceleration and ultimate recovery. The effect of fracture conductivity is discussed separately in a series of companion papers. Simulated production data is then compared with actual field results to demonstrate variability in well performance and how this concept can be used to improve completion design, and well spacing and placement strategies.

Introduction

Fisher *et al.* (2002), Maxwell *et al.* (2002), and Fischer *et al.* (2004) were the first papers to discuss the creation of large fracture networks in the Barnett shale and show initial relationships between treatment size, network size and shape, and production response. Microseismic fracture mapping results indicated that the fracture network size was related to the stimulation treatment volume. **Figure 1** shows the relationship between treatment volume and fracture network size for five vertical Barnett wells, showing that large treatment sizes resulted in larger fracture networks. It was observed that as fracture network size and complexity increase, the volume of reservoir stimulated also increases. Fisher *et al.* (2004) detailed microseismic fracture mapping results for horizontal wells in the Barnett shale. This work illustrated that production is directly related to the reservoir volume stimulated during the fracture treatments. In vertical wells, larger treatments are the primary way to increase fracture network size and complexity. Horizontal well geometry provides other optimization opportunities. Longer laterals and more stimulation stages can also be used to increase fracture network size and stimulated reservoir volume. Mayerhofer *et al.* (2006) performed numerical reservoir simulations to understand the impact of fracture network properties such as SRV on well performance. The paper also showed that well performance can be related to very long effective fractures forming a network inside a very tight shale matrix of 100 nano-darcies or less.

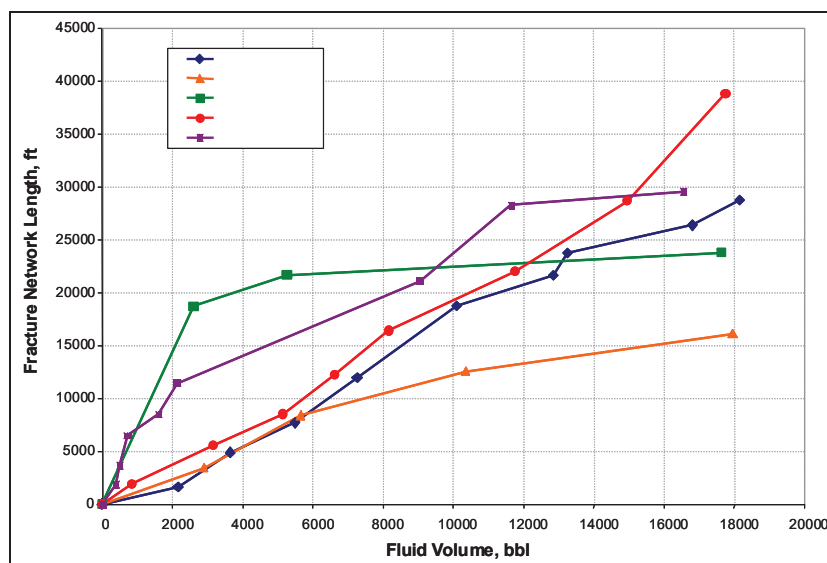


Figure 1. Relationship of total fracture network length as a function of total job fluid volume pumped (SPE 77441)

Figure 2 illustrates the various types of fracture growth ranging from simple fractures to very complex fracture networks. Complex fracture networks are desirable in “super-tight” shale reservoirs since they maximize fracture surface contact area with the shale through both size and fracture density (spacing). Chances for creating large tensile fracture networks are increased by pre-existing healed or open natural fractures and favorable stress-field conditions such as a small difference in principal horizontal stresses. Figure 3 shows an example of a complex fracture network in a vertical well measured with microseismic mapping. The figure illustrates the development of a large-scale network with two distinct, orthogonal fracture orientations. This paper aims to expand on the previous papers by discussing in more detail the concept of stimulated reservoir volume and its relationship with shale well performance.

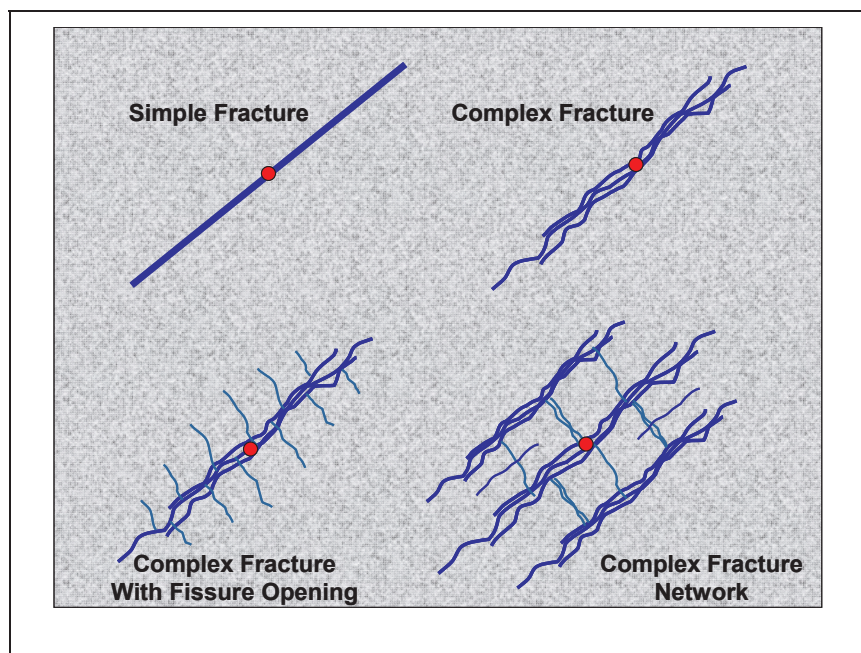


Figure 2. Types of fracture growth (from SPE 114173)

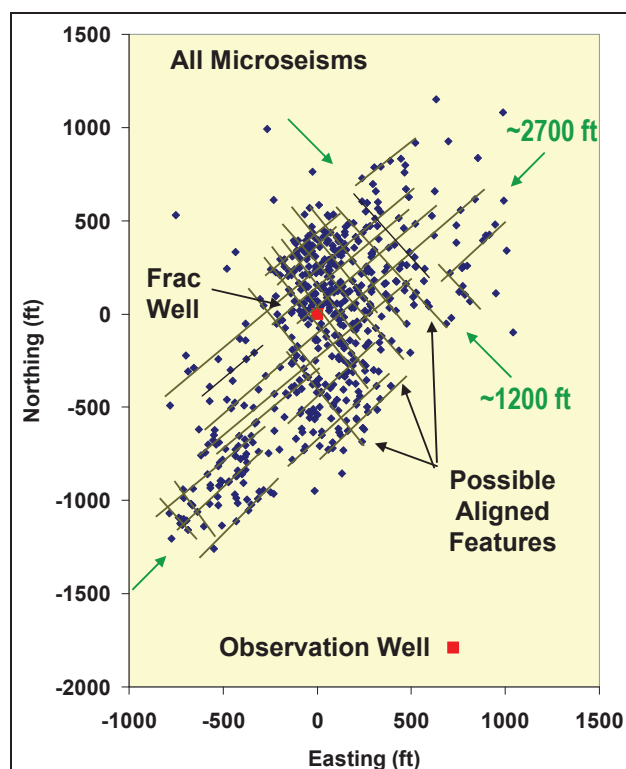


Figure 3. Microseismic fracture mapping shows complex network growth in shales (SPE 114173)

Estimating Stimulated Reservoir Volume (SRV)

It has been well documented by Albright and Pearson (1982), Warpinski *et al.* (2001), and Rutledge *et al.* (2003) that microseismic events are mainly created as a result of shear slippages around the hydraulic fractures. The mechanisms include shear slippages induced by altered stresses near the tip of the fractures as well as shear slippages related to leakoff induced pore pressure changes. In conventional reservoirs with higher reservoir permeabilities and/or oil/water reservoirs, the microseismic event cloud can be fairly wide but may not be related to the generation of complex fracture networks. In this case most of the events may be related to pore pressure increase as a result of rapidly moving pressure transients in high permeability formations and/or reservoirs with fairly incompressible fluids. In “super-tight” shale reservoirs diffusivity related pore pressure changes cannot move very far from the actual fracture planes, unless natural fractures in alternate directions are opened and hydraulically enhanced as a network structure, thus serving as a conduit for fluid movement. This means that a large event cloud structure must be approximately equivalent to the actual fracture network size. Thus, the microseismic event cloud structure observed by microseismic fracture mapping provides a means to estimate the SRV in very tight reservoirs.

Figure 4 shows an automated method using discrete bins to estimate SRV from microseismic mapping data in a horizontal well. Constant width bins (e.g., 100 ft wide) are drawn in the principal fracture direction from the wellbore to the furthest event in the specific bin on both sides of the wellbore. The individual bin areas are then summed up to approximate the total stimulated reservoir area (SRA). The calculation of SRV (a 3-dimensional structure) also requires an estimate of the stimulated fracture network height in each discrete bin within the contacted shale section. This calculation is also performed within the selected bins and is performed by calculating the network height as the difference between the shallowest and deepest event within the specific bin and top and bottom of the shale section (Figure 5). While this method is not an analytically exact calculation, it does provide a fast automated method to approximate a very complex 3-dimensional structure, while honoring the contact with the actual shale section. The SRV in this paper is specified in millions of cubic feet or acre-ft.

An important aspect of the SRV measurement is the proper setup of observation well or multiple observation wells to guarantee that the entire SRV can in fact be observed. The proper design of a microseismic mapping setup takes into account maximum observation distance to ensure that the entire SRV can be imaged. Microseismic moment magnitude versus distance plots (Zimmer *et al.* (2007)) can be used to ascertain if all events were within observable range or if the SRV could in fact be larger than imaged. Other issues that affect correlations between SRV and well performance include associated formation water production, and condensate yield, which becomes relevant in less mature shales close to the oil window. Although general guidelines are applicable for SRV measurements, it is important to evaluate any given SRV measurement in conjunction with the particular reservoir setting.

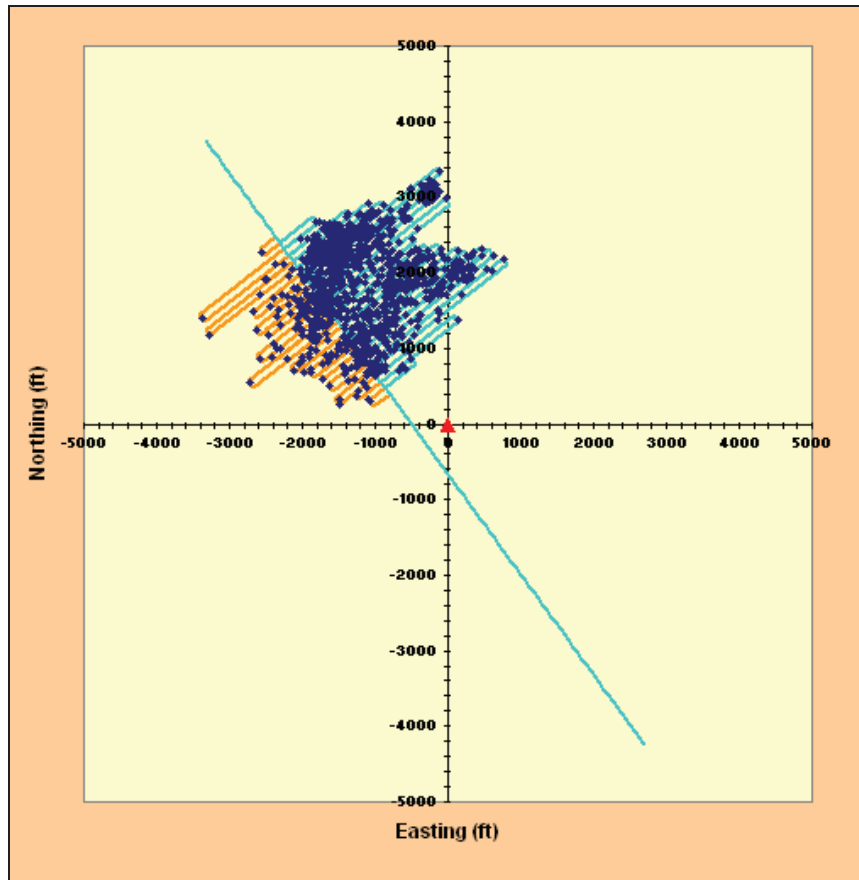


Figure 4. Estimating SRA from microseismic mapping data

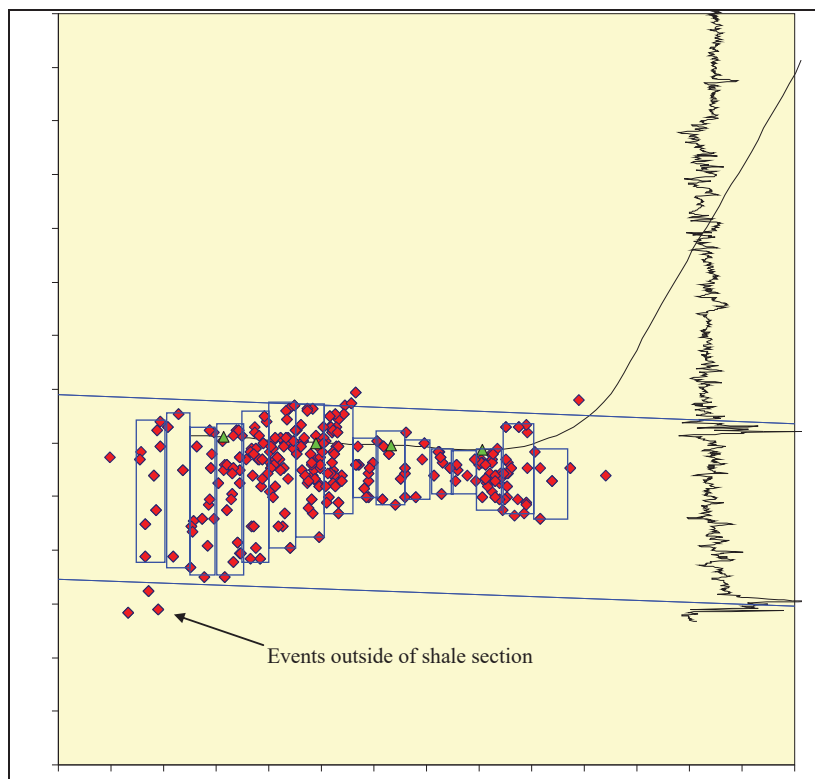


Figure 5. Conceptual sketch of SRV height calculation

SRV and Fracture Spacing in Shales

It is important to note that the SRV is just the reservoir volume affected by the stimulation. It does not provide any details of the effectively producing fracture structure or spacing. Maxwell *et al.* (2006) introduced a concept that could eventually be used to characterize fracture density. In this approach “additional seismic signal characteristics allow investigation of the source of the mechanical deformation resulting in the microseisms. In particular, the seismic moment, a robust measure of the strength of an earthquake or microearthquake, can be used to quantify the seismic deformation.” Besides this potential geophysical approach, reservoir modeling also provides an avenue to better evaluate the effectively producing network. The details of this approach will be described in the following section. As an introduction **Figure 6** shows an identical SRV with different fracture spacings (densities) and the effect of fracture spacing on the gas recovery factor. The SRV in this graph is about $2,000 \times 10^6 \text{ ft}^3$ (for $h=300 \text{ ft}$). In contrast to conventional single fracture modeling using fracture half-length, the SRA (Stimulated Reservoir Area) dimensions are given by the total fracture network length ($2x_f$) and width (x_n). However, the key property for well production is really the total sum of all fracture network segments (linear feet) within the SRA, which is a strong function of fracture spacing (density).

Equation 1 shows the calculation of total fracture length, $L_{f\text{total}}$ for the entire SRV as a function of fracture network half-length x_f , width x_n and fracture spacing Δx_s .

$$L_{f\text{total}} = \frac{4x_f x_n}{\Delta x_s} + 2x_f + x_n \dots\dots(1)$$

Figure 7 shows a plot of Eq. 1 on a log-log plot for the given SRV in Figure 6. The resulting curve forms an approximate straight-line on a log-log plot. As an example, reducing fracture spacing from 300 ft to 50 ft would result in a more than 5-fold increase in total fracture length (from 48,600 ft to 264,600 ft) and would accelerate the 3-year cumulative gas recovery by about the same multiplier. This illustrates the importance of viewing SRV in context with the potential fracture spacing. A dual porosity approach is not utilized at this point since the fracture spacing is still relatively sparse and the numerical approach better illustrates the linear flow patterns in a low permeability shale system.

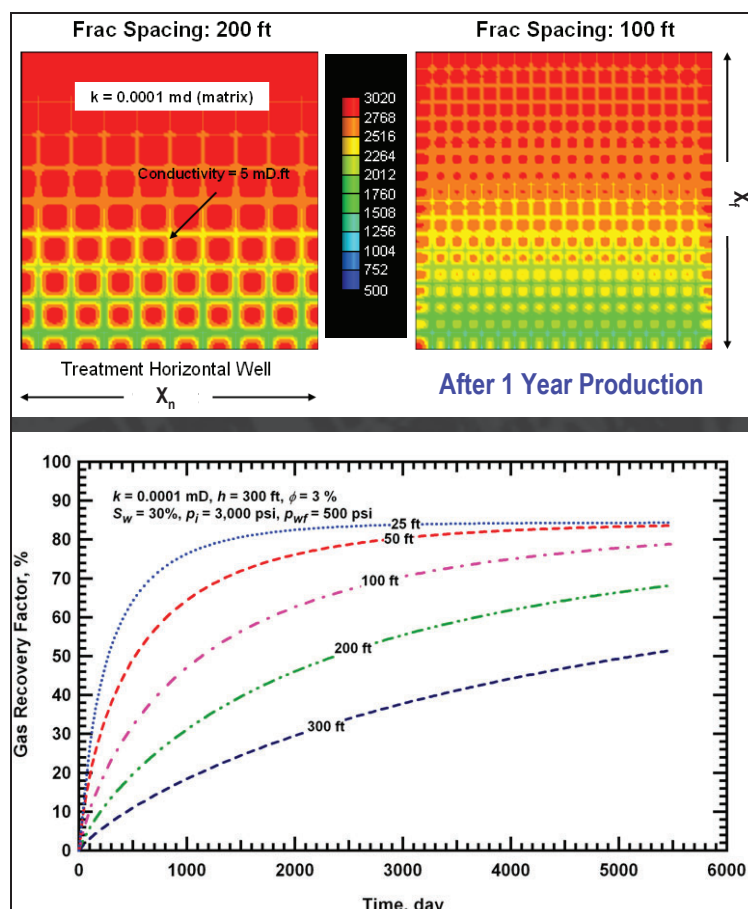


Figure 6. Effect of fracture spacing (Δx_s) on well performance and recovery factor for SRV~ $2,000 \times 10^6 \text{ ft}^3$ (from SPE 102103 & 114173)

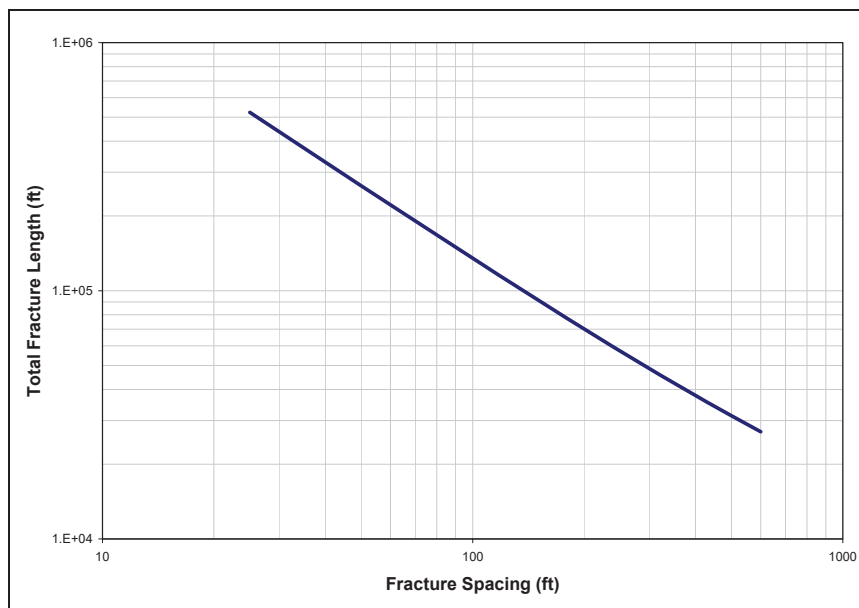


Figure 7. Fracture spacing versus total fracture length based on Eq. 1 for SRV of $2,000 \times 10^6 \text{ ft}^3$

SRV and Well Performance

Previous publications have briefly discussed the relationship between actual SRV and well performance. Here we will expand on the subject with more details and comparisons with longer-term production data from the Barnett shale. **Figure 8** shows a plot of SRV measured from microseismic fracture mapping versus 6-month cumulative gas production from a group of horizontal wells in one specific county in the Barnett shale. The plot shows that SRV's in this county range from as low as $120 \times 10^6 \text{ ft}^3$ (2,755 acre-ft) to about $1,900 \times 10^6 \text{ ft}^3$ (43,618 acre-ft). Small SRV's were partly generated as a result of shorter laterals and smaller treatment sizes (fluid volumes). While the data shows some scatter, it clearly indicates a trend that large SRV's will result in better well performance. A similar trend is still valid when plotting SRV versus longer term 3-year cumulative gas production (**Figure 9**). The scatter in the data is to be expected as a result of variations in fracture spacing within the SRV and potential differences in effective network size and conductivity. While the presented trends in Figure 8 and Figure 9 show a general relationship between generated SRV from microseismic mapping and production, it does not provide any deterministic quantification of how the actual effective network (portion of the network contributing to gas production) is structured to provide the specific gas production. The quantification of the effectively producing fracture network can only be performed with flow simulations such as provided by a numerical reservoir simulator.

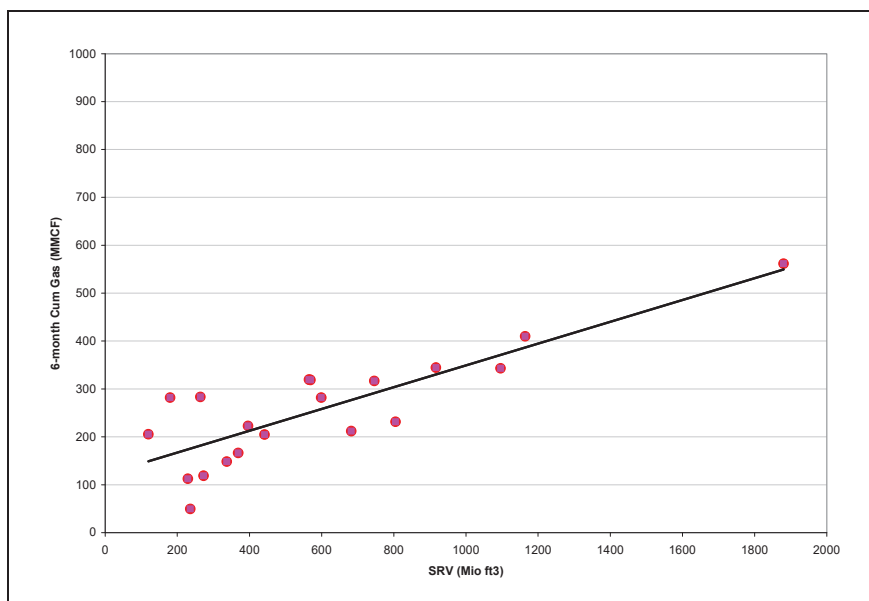


Figure 8. SRV trend versus 6-month cumulative horizontal well production for one Barnett shale county

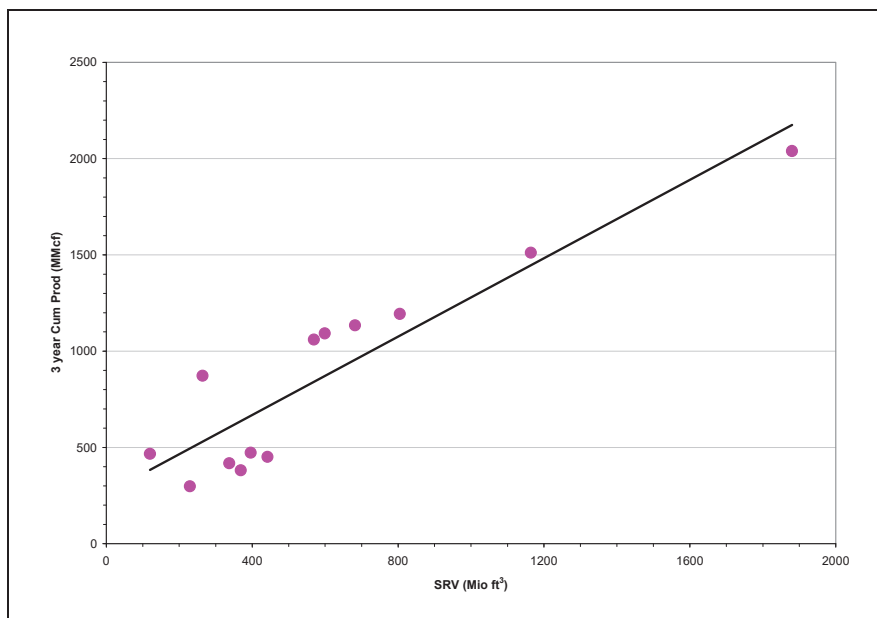


Figure 9. SRV trend versus 3-year cumulative horizontal well production for one Barnett shale county

Previous work has provided extensive numerical reservoir modeling (Mayerhofer *et al.* 2006, Warpinski *et al.* 2008, Cipolla *et al.* 2008) to show how specific fracture network properties can affect well performance. The work demonstrated that numerical modeling using a blackoil reservoir simulator can adequately history-match well performance. The numerical modeling describes the fracture network as a discrete set of high permeability fractures in two orthogonal directions, with one direction representing the principal hydraulic fracture direction as a result of newly created fractures or opening of natural fractures and the orthogonal set representing opening of conjugate natural fracture sets. Besides geochemical shale properties and pore pressure, the key fracture network properties that affect well performance include SRV, shale matrix permeability, fracture spacing and fracture conductivity. It was discussed in these papers that once the value for shale permeability is fixed, the solutions for total cumulative fracture length (the sum of all fracture segments in the network) and conductivity become fairly unique. **Figure 10** shows the results from a vertical well history match (Mayerhofer *et al.* 2006), where the network was approximated with an effectively producing network having almost 8,000 ft of total fracture length within a microseismically mapped SRV of $219 \times 10^6 \text{ ft}^3$ (gray dots in graph). Fracture spacing was modeled to be about 180 ft in the principal fracture direction with a uniform fracture conductivity of 4 md-ft, and shale matrix permeability of 100 nano-darcy (0.0001 md). The fracture network is larger on the southwest side of the wellbore with only a few microseismic events to the northeast.

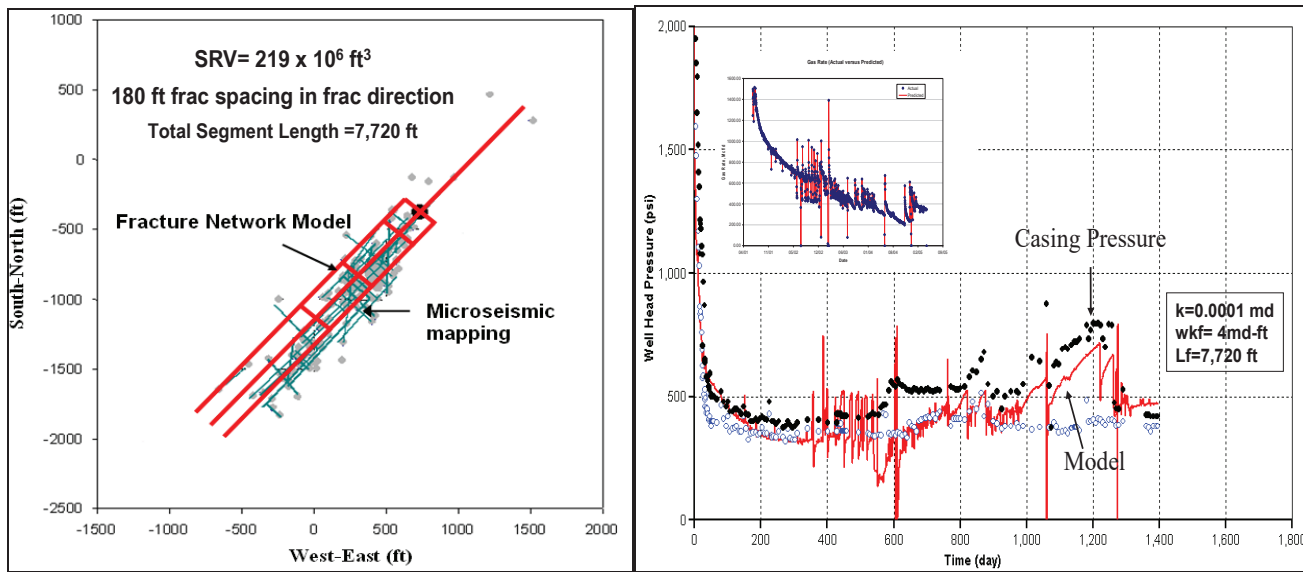


Figure 10. Reservoir simulation results for vertical well from SPE 102103

Figure 11 shows the simulation setup for a 3,000-ft long horizontal well, from which a SRV of $5000 \times 10^6 \text{ ft}^3$ with equidistant frac spacing of 400 ft was generated. The plot clearly shows that the ultimate drainage area is constrained to the created SRV in “super-tight” shale reservoirs. Using this approach, a series of simulations was generated with different SRV sizes and fracture spacings to evaluate the effect of these properties on well performance. The SRV was varied from about $800 \times 10^6 \text{ ft}^3$ to $6,000 \times 10^6 \text{ ft}^3$ and equidistant fracture spacing from 50 to 800 ft.

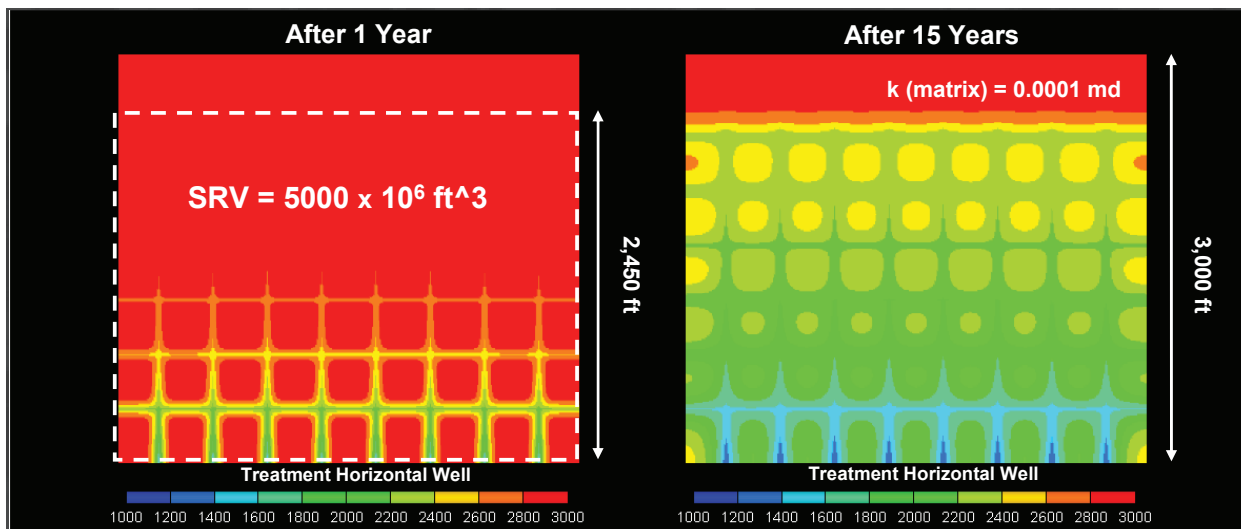


Figure 11. Simulation of horizontal well fracture network (SRV= $5000 \times 10^6 \text{ ft}^3$, Frac Spacing= 400 ft, Lateral Length~ 3,000 ft)

To crosscheck the generic simulations with actual well production data and a more detailed production history match, the vertical well example in Figure 10 was plotted against the more generic simulation results. Although the well configuration is different and flowing pressures are not exactly the same, the correlation between SRV, well performance and fracture spacing is approximately consistent, showing that the 6-month cumulative production of this vertical well would fall on the 200-ft frac spacing curve (Figure 12). Figure 13 shows a plot of the same generic simulations with actual horizontal well Barnett shale data throughout the producing areas in North Texas. The figure shows a wide scatter of well results with cumulative gas production ranging from less than 100 MMscf to 500 MMscf for SRV's ranging from $100 \times 10^6 \text{ ft}^3$ to $3,000 \times 10^6 \text{ ft}^3$. The data indicate that most of the wells plot at a fracture spacing of 200 ft or larger, with many wells at fracture spacings larger than 800 ft, indicating a sparse fracture network (smaller total fracture length) within the measured SRV (Figure 7) and therefore a less effective fracture network. The plot also shows the significant acceleration component of smaller fracture spacings on short-term production. For example, at an SRV= $1,000 \times 10^6 \text{ ft}^3$, reducing fracture spacing from 400 ft to 100 ft would result in

a 3.5-fold increase in production. The larger the SRV, the more significant the fold of increase in production with smaller fracture spacing (due to much longer total fracture length with larger SRV). On the other hand, generating a larger SRV with large 800-ft fracture spacing will not provide increased production, which can be explained by the low fracture conductivity (and associated increasing pressure drop with distance from the well) in a sparsely fractured network.

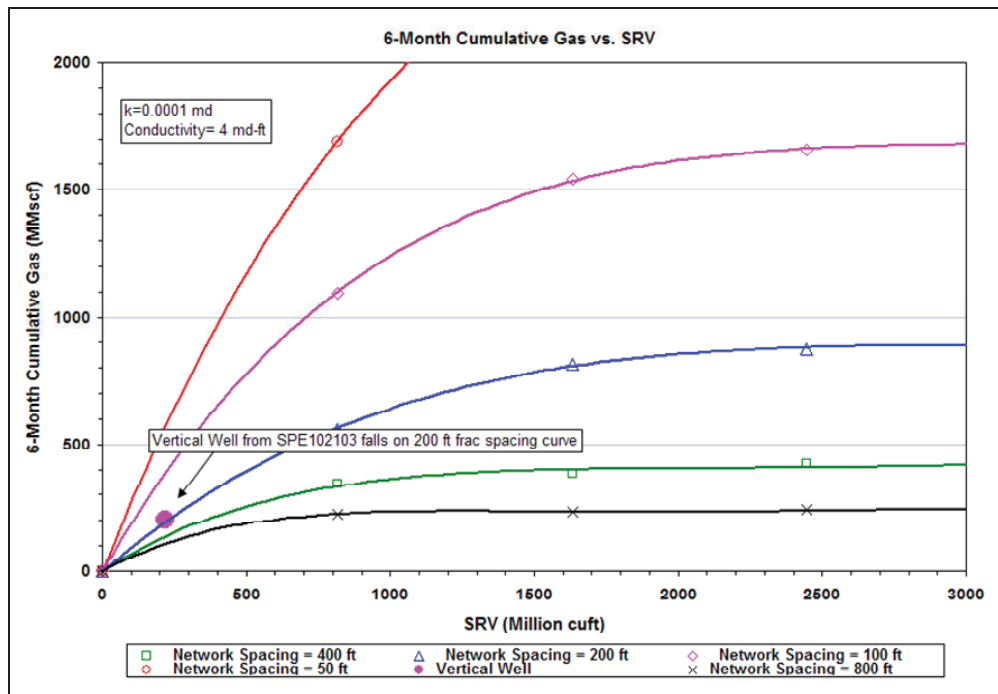


Figure 12. Simulated SRV and actual 6-month vertical well production response from SPE 102103

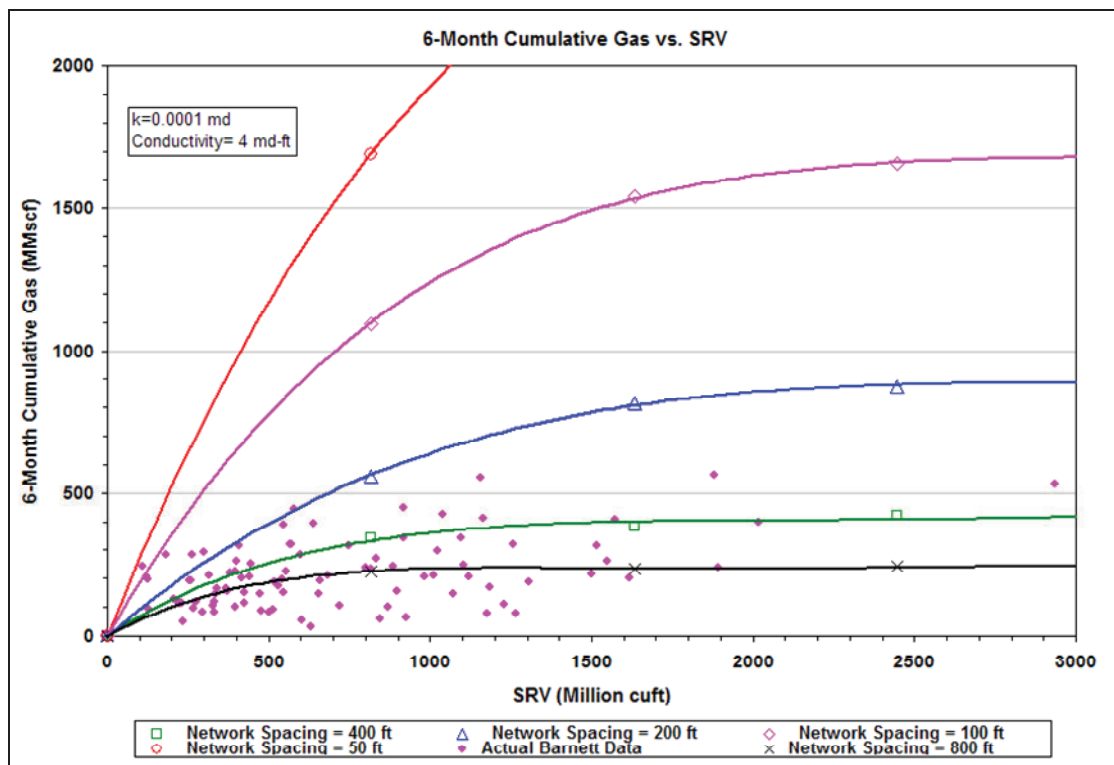
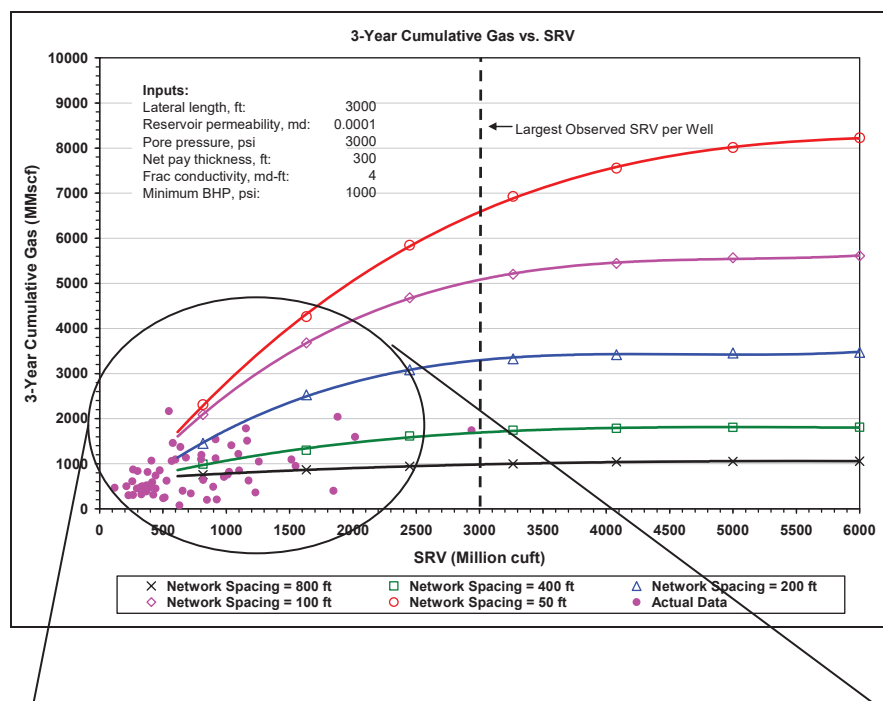


Figure 13. Simulated SRV and simulated 6-month cumulative production versus actual Barnett shale data (entire North Texas area)

After comparing short-term production, the discussion will now focus on longer-term production (3 to 15 years). **Figure 14** shows a plot of the SRV from the same generic horizontal well simulations versus 3-year cumulative gas production, fracture spacing and actual horizontal well Barnett shale data. The data indicate a slight shift of the real data to smaller fracture spacings, which may indicate improved cleanup for the longer-term production. The actual cumulative production ranges from as low as 100 MMscf to 2,000 MMscf. The simulations also show that the folds of increase in production as a function of smaller fracture spacing become less for longer-term recovery as previously illustrated in Figure 6 (early-time acceleration). The plot also clearly shows that significant improvements in well performance by generating larger SRV's is more significant at low to moderate SRV's (less than $1,000 \times 10^6 \text{ ft}^3$). For larger SRV's the benefits can only be achieved with a simultaneous decrease of fracture spacing. For example, increasing SRV from $1,500 \times 10^6 \text{ ft}^3$ to $3,000 \times 10^6 \text{ ft}^3$ with 800 ft fracture spacing will have no meaningful increase in gas production.

Figure 15 shows the results for 15-year cumulative production. In this case no actual production data is available, since horizontal well development started in 2002 in the Barnett shale. The plot shows that for longer-term production the impact of SRV becomes more significant even at larger fracture spacing since SRV provides the ultimate drainage area and diffusion has had time to access the entire network. In this case, increasing SRV from $1,500 \times 10^6 \text{ ft}^3$ to $3,000 \times 10^6 \text{ ft}^3$ with 800 ft fracture spacing will result in a 50% cumulative production increase from 2,000 MMscf to 3,000 MMscf (compared to no meaningful increase after 3 years of production).



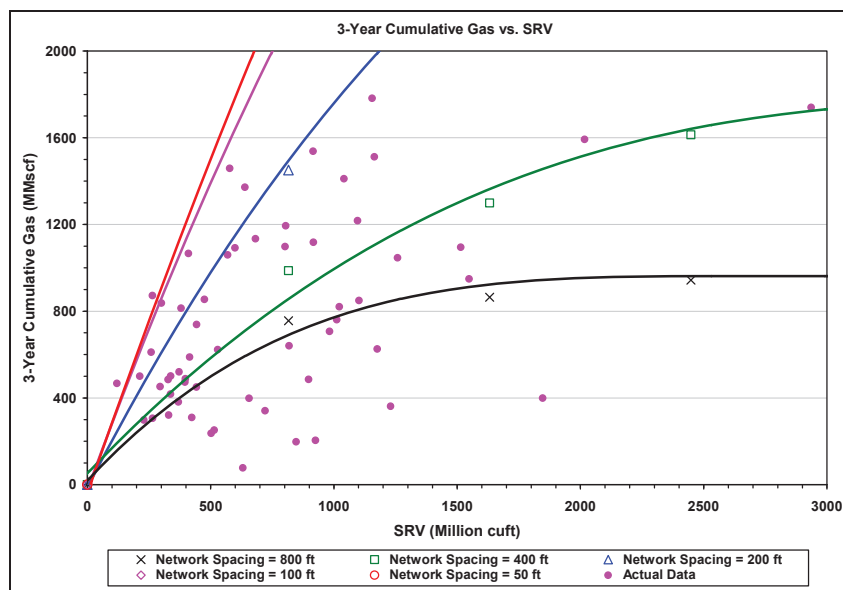


Figure 14. Simulated SRV and simulated 3-year cumulative production versus actual Barnett shale data (entire North Texas area)

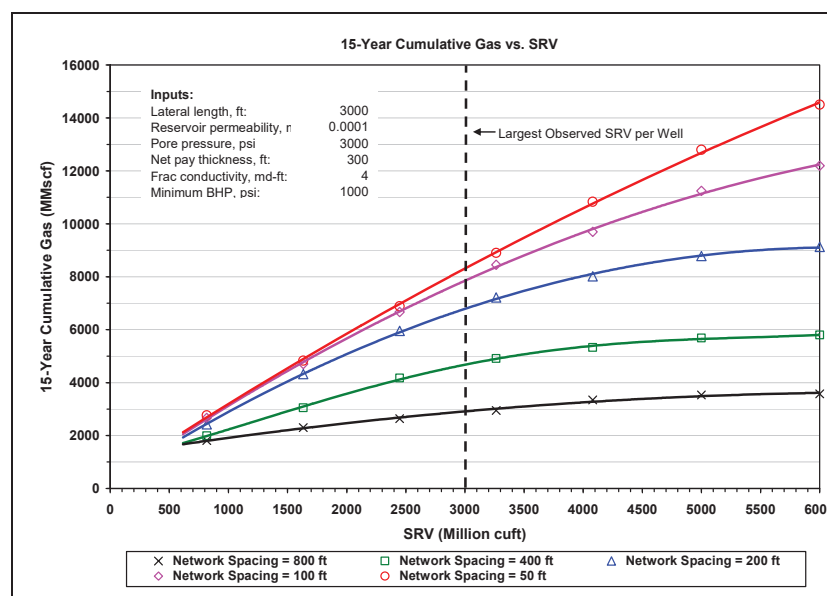


Figure 15. Simulated SRV versus 15-Year cumulative production

Applying SRV and Network Azimuth to Well Placement and Spacing Strategies

Figure 16 and Figure 17 show conceptual diagrams illustrating how SRV and fracture network azimuth can be used for well placement and spacing considerations. Figure 16 shows the importance of lateral orientation with respect to fracture network azimuth and SRV. The graph assumes that the lateral will be drilled in a NE-SW orientation. If fracture direction follows the same SW to NE trend, the scenario on the left-side of picture will promote longitudinal fractures with a very small SRV. If wells are to be drilled in this orientation, more wells with closer spacing will be required to drain a given section of reservoir. The fracture orientation provided in the center of the picture provides an oblique orientation of the fracture direction with respect to the lateral and also results in less efficient reservoir coverage but SRV is now larger than in the longitudinal case. The best scenario with largest SRV is illustrated on the right-side with transverse network orientation providing the largest SRV per lateral.

Keeping these considerations in mind, one could postulate that well spacing (distance between laterals) should roughly coincide with the extent of the SRV perpendicular to the wellbore as illustrated in Figure 17 on the left-hand side (SRV from each lateral is adjacent to the offset well). This approach may appear to be the optimum configuration. While the areal coverage of SRV is definitely optimized with this approach, gas recovery factors within the SRV can only be optimum with sufficiently close fracture spacing as illustrated in Figure 6. If fracture spacing cannot be optimized with large SRV's, it may be more beneficial to drill laterals at closer spacing, with the chance of overlapping SRV's (right-hand picture in Figure 17). This is the reason for the so-called "simul-fracs" and "zipper-fracs" in shale reservoirs where multiple parallel wellbores are either stimulated simultaneously or in short alternating sequence from one lateral to the next. The hypothesis in these strategies is to maximize fracture density between laterals as a result of stress diversion from simultaneously growing opposing fractures (simul-fracs) and/or creating new branches as a result of increased stresses around newly opened fractures. Real data from Barnett shale completions may suggest that this approach has merits but no specific study has been published on this topic. The challenge lies in understanding the practical and physical limitations of what is possible in terms of network size and fracture spacing at reasonable completion costs (*i.e.*, lateral length, number of stages, perforations and treatment size).

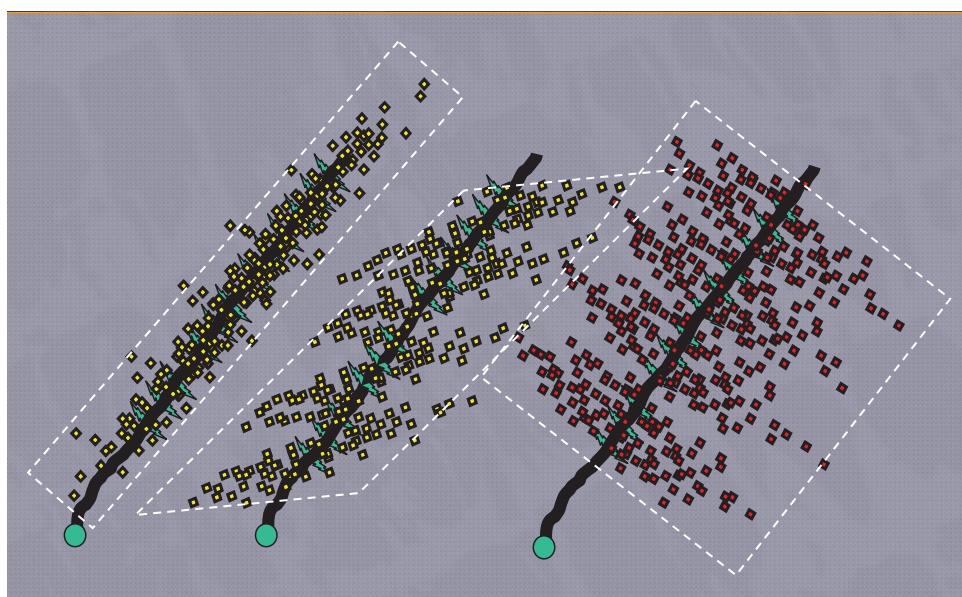


Figure 16. Importance of SRV and network azimuth for lateral orientation and well placement

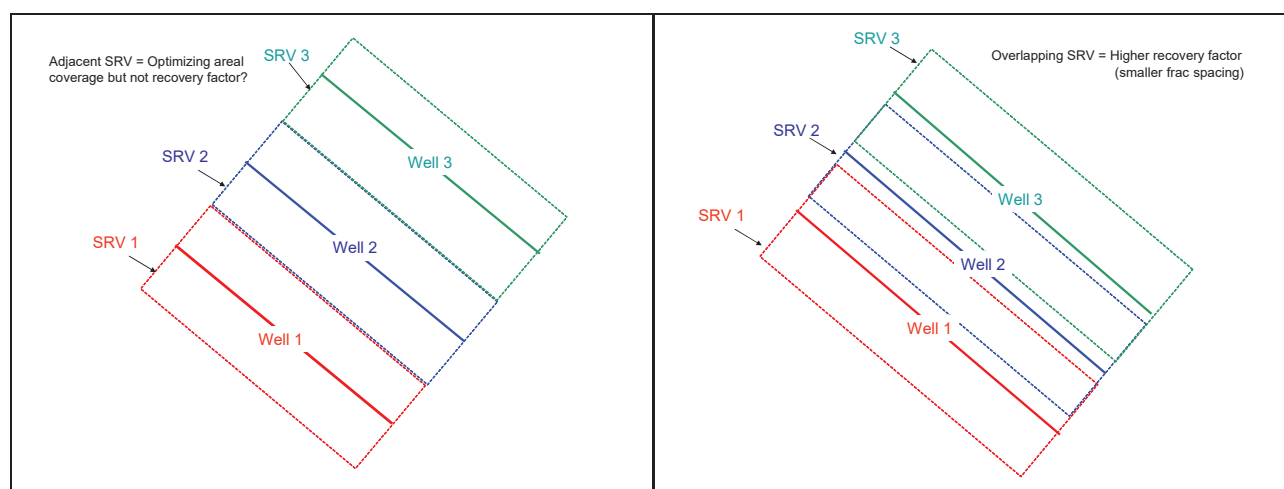


Figure 17. Horizontal well placement strategy considerations in conjunction with SRV and fracture spacing in shale reservoirs

Conclusions

1. Low permeability shale reservoirs require a large fracture network with small fracture spacing and adequate conductivity to maximize well performance. The size of the SRV, fracture spacing and azimuth are key components for well placement and spacing strategies.
2. Natural features controlling SRV and fracture spacing in shales include shale thickness, stress field and magnitude, presence of pre-existing open or healed natural fractures, fracture barriers, rock brittleness and geologic features such as faults and karsts. While these parameters are not under direct human control, it is critical to understand how they will impact well results, completion and well development strategies.
3. Engineering measures to increase SRV and fracture spacing include lateral length and orientation, treatment sizes, number of stages, perforation clusters, diversion techniques and/or openhole packer completion systems. More perforation clusters and stages in cemented and cased completions increase the likelihood of dense fracturing.
4. The key completion strategy is to balance the creation of a large SRV with maximum possible fracture density. Large SRV's with small fracture spacing provide maximum well performance and gas recovery factors. However, the practical and physical limitations of achieving this goal will require an economic optimization process.

Acknowledgments

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Nomenclature

h_f = fracture height, L
 x_f = hydraulic fracture wing or half-length, L
 x_n = hydraulic fracture network width (from microseismic event pattern), L
 Δx_s = orthogonal fracture spacing, L
 L_{total} = Total composite fracture length

SI Metric Conversion Factors

acre	x 4.046 873	e+03	=	m ²
bbl	x 1.589 874	e-01	=	m ³
cp	x 1.0	e-03	=	Pa.s
ft	x 3.048	e-01	=	m

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