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Expanding Sustainable Shale Gas Supply through Hydraulic Fracturing Efficiency Improvements

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Abstract

Commercial quantities of gas produced from shale resources can only be realized through reservoir stimulation, such as hydraulic fracturing. Although hydraulic fracturing is a proven production enhancement technique, there is much room for improvement in the design and execution of each hydraulic fracture stage as evident in production logs. In most cases, in long horizontal wells there are few very productive fracture stages with the majority of other stages producing little or no gas. By improving the efficiency of each hydraulic fracture stage, more gas can be produced while minimizing the input of energy and water, thus improving shale gas economics and reducing environmental impact. This paper examines the use of microseismic imaging and production logging on improving the design and efficiency of individual hydraulic fracture stages in the Marcellus shale. Microseismic data from a multi horizontal well pad, that included 93 fracture stages, was used to identify areas of natural fracture swarms, while production logs confirmed greater production in these zones. Furthermore, we present how microseismic imaging can be used to predict hydraulic fracturing interaction with natural fractures and how this interaction impacts hydraulic fracture design and spacing. By using the microseismic-cloud length-to-width aspect ratio, we were able to verify presence of natural fractures and propose a new, non uniform hydraulic fracture spacing design. Finally, we compare the production results with mud log gas shows and propose a method for determining hydraulic fracture spacing such that the great majority of stages – if not all - contribute significantly to the aggregate production.

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Introduction

Commercial quantities of gas recovery from shale reservoirs require intensive drilling and completion operations. This includes tight horizontal well spacing and extensive reservoir stimulation through hydraulic fracturing. Although hydraulic fracturing is a proven production enhancement technique, there is much room for improvement in the design and execution of each hydraulic fracture stage as evident in production logs. Operational efficiency has greatly improved over the years through multi well pad drilling and installation of rapid completion systems such as pump down plug-and-perf techniques and shifting sleeves. In most cases, in long horizontal wells there are few very productive fracture stages with the majority of other stages producing little or no gas. The production performance of individual fracture stages has to improve in order to assure sustainable shale gas supplies. By improving the efficiency of each hydraulic fracture stage, more gas can be produced while minimizing the input of energy and water, thus improving shale gas economics and reducing environmental impact.

Field based experiments in producing wells offer the greatest amount of insight into what works and what doesn’t, while generating invaluable data for engineering analysis. This paper provides an overview of recently completed and an ongoing field based collaborative research experiments in the Marcellus Shale. Analysis of microseismic data from a multi horizontal well pad, where 93 fracture stages were pumped, was used to identify areas of natural fracture swarms, while production logs confirmed greater production in these zones. Furthermore, we present how microseismic imaging can be used to predict hydraulic fracturing interaction with natural fractures and how this interaction impacts hydraulic fracture design and spacing. By using microseismic-cloud length-to-width aspect ratio, we were able to verify presence of natural fractures and propose a new, non uniform hydraulic fracture spacing design. Finally, we compare the production results with mud log gas shows and propose a method for determining hydraulic fracture spacing such that the great majority of stages – if not all - contribute significantly to the aggregate production.

Project background

Gas Technology Institute (GTI) recently completed a research and development project focused on the development of techniques and methods for delineation of the stimulated reservoir volume and characterization of operational parameters influencing growth and attributes of hydraulic fractures. The project has been funded by Research Partnership to Secure Energy for America (RPSEA). Range Resources Appalachia LLC was a producing partner and provided cost sharing, background data, technical support, and access to several wells in the Marcellus in southwest Pennsylvania (Figure 1) for field data acquisition. Technical support and significant cost sharing was also provided by Schlumberger.

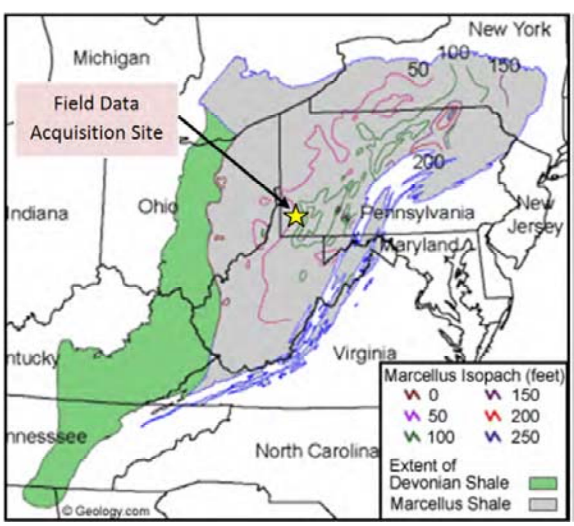

Figure 1: Field data acquisition site.

A team of experts from GTI, Bureau of Economic Geology (BEG) at the University of Texas – Austin, Lawrence Berkeley National Laboratory (LBL) and; Stanford, West Virginia University (WVU), and Pennsylvania State University (PSU) began research on this multidisciplinary project in early 2011. The project was completed in 2013.

Great emphasis was placed on comprehensive fracture diagnostics, coupled with analysis of microseismic data, fracture geometry, and production data as means for determining fracturing efficiency (Ciezobka 2011). In the meantime, realizing that the state and spatial distribution of natural fractures are significant parameters influencing growth and volumetric extent of fracture networks, extensive efforts were also placed on characterization of natural fractures as the prerequisite for thorough analysis of hydraulic fracturing data, determination of the stimulated reservoir volume and ultimately; development of optimized completion strategy for Marcellus and other naturally fractured shale formations.

Experiment site

A multiple well pad owned and operated by Range Resources Appalachia LLC located in Washington county Pennsylvania was the site of field data acquisition. The pad includes seven nearly-parallel horizontal wells. The trajectories of the well laterals are in the general northwest direction and are normal to the maximum in situ horizontal stress (σ_{Hmax}) orientation as shown in Figure 2. Spacing of the horizontal sections of the wellbores is approximately 500 ft with an average horizontal wellbore length of 3640 ft. The horizontal well sections lie along the lower portion of the Marcellus shale, (the Marcellus-A) having a true vertical depth (TVD) of approximately 6500 ft. Gross thickness of the shale is roughly 150 ft with an average porosity and permeability of 8 percent and 600 nanodarcy, respectively. Data from five nearby science wells was used to characterize the Marcellus reservoir. Whole cores and a suite of advanced electric logs were used to determine petrophysical, mechanical and other rock properties. The cores were also used to calibrate the electric logs. Surface geophones were installed in a roughly 3 square mile area and 93 fracture stages were monitored. Borehole microseismic tools were placed in one of the horizontal wells and 62 fracture stages were monitored.

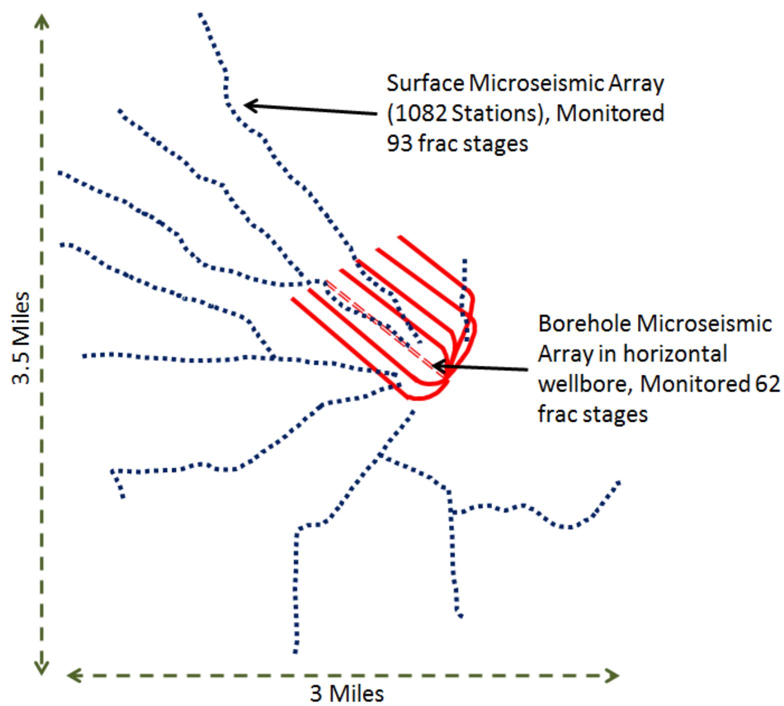

Figure 2: Layout of surface and borehole microseismic arrays and horizontal well trajectories.

Natural fracture identification from microseismic and mud log data

Using the following data: gas shows from mud logs, fracture Length to Width aspect ratio (microseismic cloud length divided by width as shown in Figure 3), microseismic event count for each fracture stage, and the results from the post frac production log, we compared how hydraulic fracture dimensions affect production and relate the gas production to the initial gas that was encountered during drilling as seen in the mud logs. In areas along the horizontal lateral where the wellbore intersects a swarm of natural fractures, gas shows are expected to be high as the natural fractures provide a conduit to gas flow. This is because high gas shows in ultra-low permeability reservoirs can be attributed to natural fractures, since the gas shows are primarily a result of gas being discharged from the natural fractures into the wellbore.

On the other hand, in areas along the wellbore where there are no natural fractures or the natural fracture concentration is low, the gas present in the drilling mud should be low.

When considering the fracture dimensions of each individual fracture stage, we can quantify the fracture geometry in terms of the fracture Length and Width. The fracture length is the extent of the microseismic event cloud at a distance normal to the wellbore and the fracture width is the extent of the microseismic cloud along the wellbore. Thus the fracture width presented here is the fracture network width and not individual fracture aperture, as shown in Figure 3. In the areas where there are little or no natural fractures present, we can expect to see a simple hydraulic fracture or fractures that are long and closely spaced. Conversely, in areas along the wellbore that exhibit a high degree of natural fracturing we would expect to see many hydraulic fractures spaced far apart and intersect with natural fractures, thus forming a complex and wide fracture network. However, this complex fracture network should be shorter than an individual hydraulic fracture since much of the fracturing fluid is used to expand the fracture network along the wellbore and connect the natural fractures as opposed to creating a single long hydraulic fracture. In the case where there is a moderate degree of natural fracturing along the horizontal wellbore, the created hydraulic fractures should exhibit some complexity due to the interaction with natural fractures and should be longer than a complex fracture network that is created in the presence of high natural fracturing. But this moderately complex fracture network should be shorter than a simple hydraulic fracture that is created in the absence of natural fractures as shown in Figure 4.

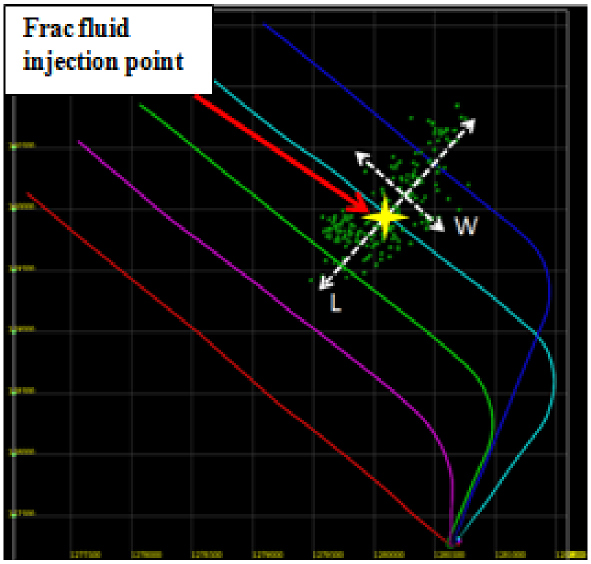

Figure 3: Plan view of horizontal wells witch microseismic data for a single frac stage showing the fracture geometry in terms of fracture width and length. The fracture width here is the width of the fracture network and not the fracture aperture.of natural fractures.

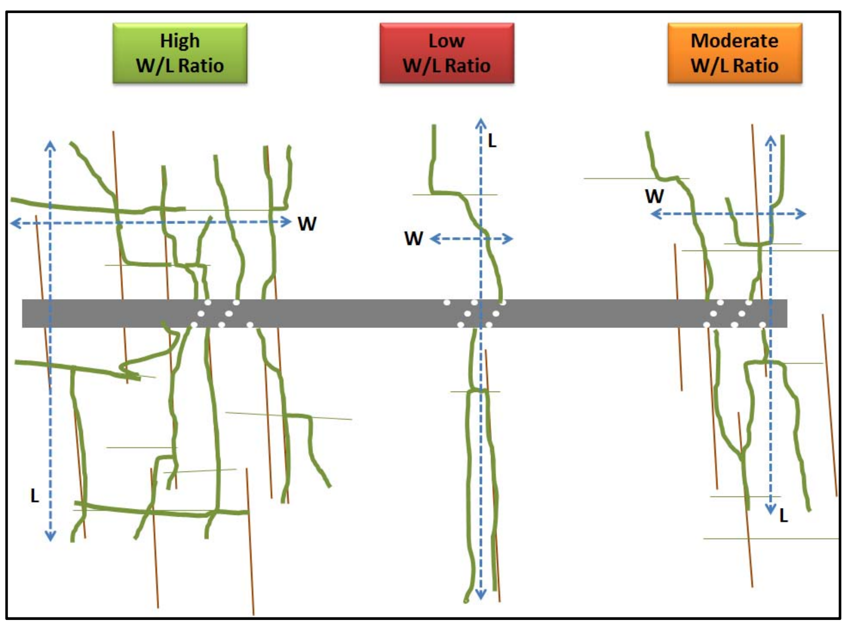

Figure 4: Fracture network creation in the presence of natural fractures

Another important parameter to consider when evaluating stimulation efficiency is the number of microseismic events captured during a hydraulic stimulation treatment. This parameter heavily depends on proximity of geophones to the signal source and when in close proximity, the geophones should record a large number of microseismic events. As the events occur farther and farther from the geophones, they should still be recorded, although with lesser location accuracy.
If we consider the three cases shown in figure 4; where the wellbore intersects a

concentrated swarm of natural fractures, few natural fractures, and almost no natural fractures, we can qualitatively predict the number of microseismic events that would be recorded in each case. In the case of a hydraulic fracture or fractures intersecting a concentrated swarm of natural fractures, we can expect a large number of microseismic events. This is due to the fracturing fluid changing direction many times and fracturing new rock while intersecting natural fractures and creating a complex fracture network. In cases where there are few natural fractures that intersect and are near the wellbore, there should be fewer recorded events relative to the previous case. This is a result of fewer hydraulic fractures intersection with natural fractures and changing direction. In the third case, where there are few or no natural fractures at all, we expect to record a low number of microseismic events. This happens because the hydraulic fracture is simple as it does not intersect with natural fractures. Furthermore, under this condition, the hydraulic fracture quickly propagates away from the wellbore and many of the microseismic signals are too far from the geophones to be recorded and located accurately. Figure 5 shows the results of the borehole microseismic survey from the test site mentioned earlier. There are areas that exhibit a high concentration of microseismic events, moderate concentration of microseismic events, and areas of few or no microseismic events. These results are quite surprising given that the fracture spacing in all wells was almost identical and large fluid and proppant volume pumped. Additionally, the geophones in the horizontal monitoring well were moved 5 times along the wellbore to reduce the listening distance, or spatial bias, as the fracturing treatments were executed in a zipper sequence. This evidence, along with fracture diagnostics related to pressure variations during pumping clearly substantiate the notion that natural fractures in the Marcellus manifest themselves in swarms or clusters. The evidence is further supported by results from a production log. Although all perforation clusters contribute to production, the areas where there is evidence of natural fracture swarms the productivity is much higher as discussed in later sections.

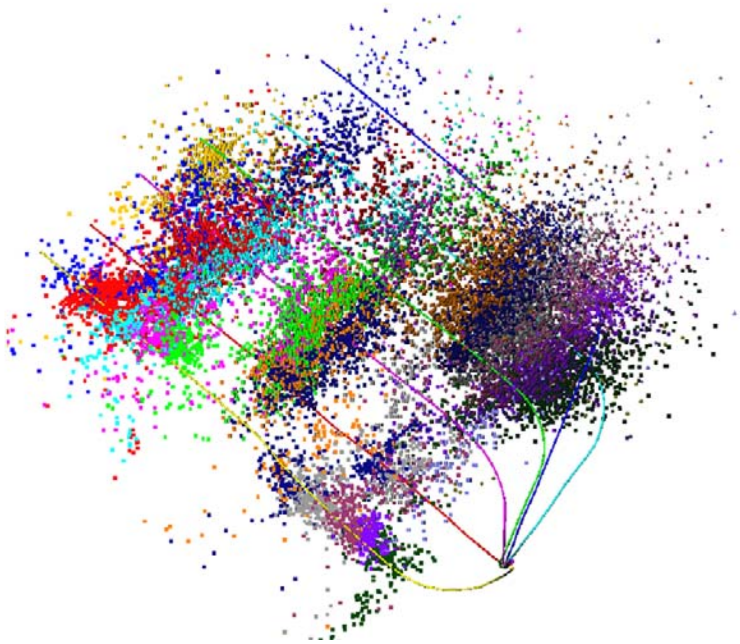

Figure 5:Results of the microseismic survey showing the recorded events for each frac stage.

Further identification and impact of natural fractures on production

Most shale plays, including the Marcellus, have some naturally occurring fracture networks in the form of swarms and depending on the in-situ conditions and properties of the injected fluid/ proppant, may significantly enhance the productivity of fracture stimulated wells. In the Marcellus play, prior data suggests presence of natural fracture swarms as a result of local stress perturbations occurring over geologic timelines (Engelder et al., 2009). These natural fractures (mainly J_1 and sets J_2 sets) are known to contribute significantly to overall production by providing additional surface area for gas to move from matrix to the connected fractures and eventually to the producing well.

Identification of naturally fractured zones is a key element in accurate understanding of well behavior but this is not easy to achieve due to the need for use of indirect measurement techniques or proxies to identify the zones where the reservoir is fractured. While there are many available techniques for fracture characterization in reservoirs, in addition to mud logs gas shows, we use local passive seismic monitoring data, also referred to as microseismic (small earthquake) data to characterize the presence or absence of fractures. This is made possible due to the ways in which hydraulic fractures interact with naturally fractured rock and the impact such interaction has on the final fractured rock volume in terms of network complexity, network dimensions and magnitude distribution of the microseisms (Bahorich et al., 2012).

In this context, we look at two different properties evaluated based on the distribution of induced microseismicity associated with hydraulic fracturing process. The first is the b-value distribution which is obtained from the Gutenberg-Richter law providing the relationship between the magnitude of the seismic event and the total number of earthquakes in any given region and time period (Gutenberg and Richter, 1954). The relation for b is as follows:

$$log_{10}N = 1 - bM$$

In this equation, N is the number of earthquakes with substantially smaller magnitude relative to that of the main event M. Higher b-value is indicative of a larger portion of small earthquakes compared to large ones. Since in the presence of natural fracture swarms, many re-activations are expected, b-values tend to be higher when hydraulic fracture interacts with such zones (Boroumand, 2014). In this study, we look at the overall distribution of events and their b-value estimates for every completed stage and try to interpret our observations (production) with these estimates. We expect zones showing higher b-value could be indicative of the presence of natural fractures and therefore, should correlate strongly with gas shows and production log data from some of these test wells. Similarly, higher L/W ratio (or the ratio of the two principal dimensions of the event cloud) is indicative of long and straight created fractures with lower degree of complexity in the created network. On the other hand, a lower L/W ratio suggests more complex network which could be due to substantive interaction of the propagating hydraulic fractures with natural fractures (Ciezobka & Salehi, 2013). Figure 6 shows L/W aspect ratio as mapped with borehole microseismic data and how it correlated with calculated b-values for the same stages. Figure 7 shows another example where b-value has been compared with production logs and other relevant data to highlight these observations and how they correlate with mud log gas shows. We observe reasonably strong correlation between computed b-values and observed fracture density from image logs for most of the completed stages. We also observe strong correlation between sections showing very high flow contribution and sections indicating highly complex fractured zones from b-value map. Finally, we observe a reasonably strong correlation between observed production and highly fractured sections of the reservoir as well as a moderately strong correlation between production and relatively high gas presence from mud log gas show data.

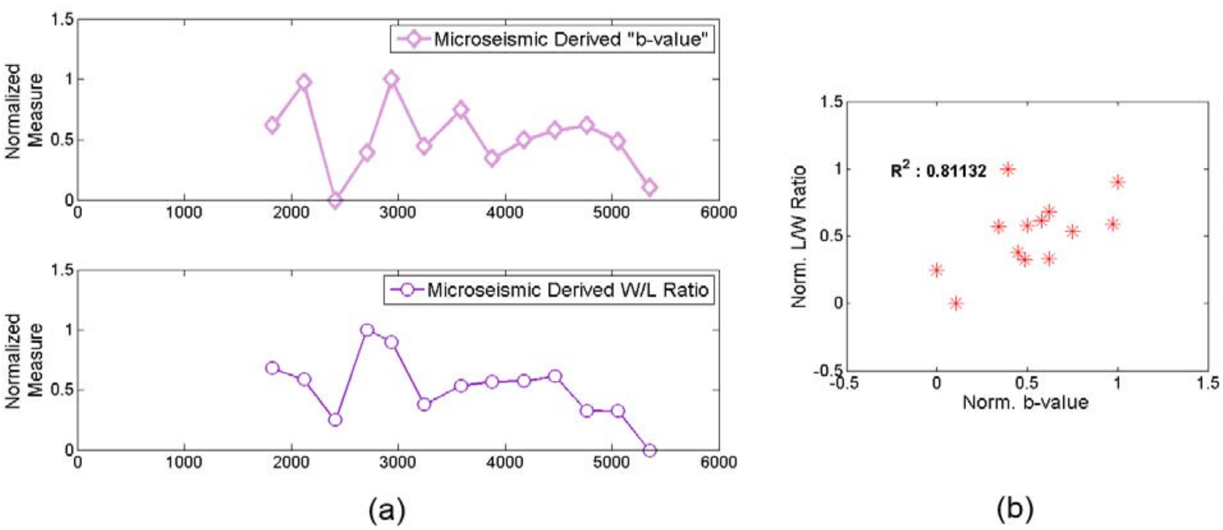

Figure 6: Subplot (a) shows the microseismic derived L/W aspect ratio and b-value maps for completed stages and (b) shows a crossplot between these two measures indicating strong correlation between the two parameters (R2= 0.81).

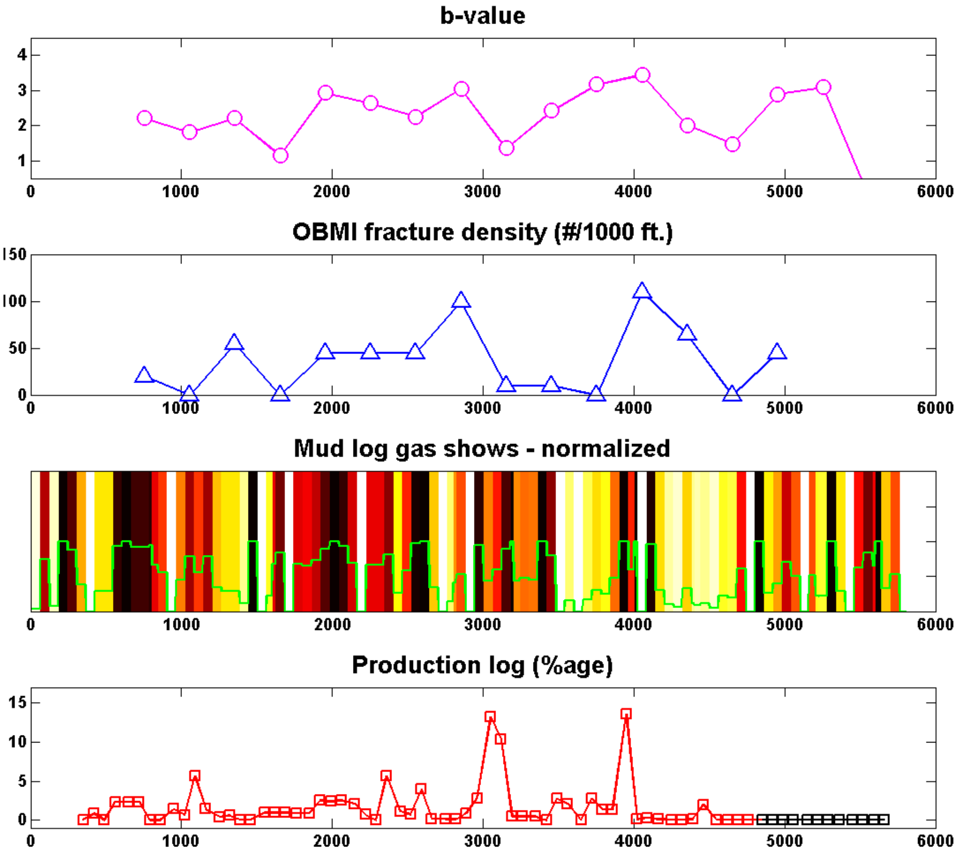

Figure 7: Composite plot of seismic derived b-value (per stage), evaluated fracture density from OBMI log (per stage), normalized mud log gas shows and observed early period production from the completed well. The darkened section at the tail end of production log indicates perforation clusters for which logging failed and data is unavailable.

The observed correlation between mud log gas shows and production provides for the basis of our stage/ cluster spacing optimization workflow. Even though the correlation is not perfect, in conjunction with gamma log readings and ROP data, a strong correlation between the observed production and modeled properties governing production in shale reservoirs should be possible as it would take care of some of the outlier observations. Based on the observations, our design workflow involves utilizing relevant routinely logged data from mud logs (gas shows, ROP and gamma) and model for rock properties such as Young's Modulus and Poisson's Ratio. These in turn are used to predict rock brittleness which is used in conjunction with gas shows to identify the optimal hydraulic fracture/ cluster density along the lateral. Based on this hydraulic fracture density model, clusters are populated along the length of the lateral by honoring the background modeled density values. The approach involving evaluation of reservoir and completion quality to design hydraulic fractures is a recent phenomenon (Borstmayer et al., 2011) but still lacks widespread application due to high costs associated with specialty logs.

The current 'run-of-the-mill" approach to fracture spacing during hydraulic fracture stimulation of shale plays involve equally spaced stages with similar stage designs in terms of fluid and proppant being pumped to complete the stages. While these stages are designed with an attempt to optimize for fracturing efficiency, most completions fail to account for the extreme variability in reservoir properties that the wellbore encounters along the lateral. This approach has resulted in completions with many stages showing insignificant to zero production contribution from post completion production logs or from DTS data. This is indicative of a highly ineffective and sub-optimal design approach and the potential use of reservoir quality parameters based on routinely collected mud log data provides an opportunity to optimize productivity of wells without resorting to the use of very expensive logging tools (such as dipole sonic, azimuthal gamma, etc.).

Improved fracture spacing using routinely logged mud log data

Apart from the pre-completion drilling data, the proposed workflow requires some science data (rock properties derived from specialty logging) which is necessary to model for the same properties based on routine MWD data. Figure 8 shows the overall design workflow followed in our approach. Training well is nominated based on availability of relevant specialty logging data and the exact position of the well in relation to various shale sub-layers. The data from this well is used to model for relevant rock properties which in turn are used to identify required hydraulic fracture (cluster) density along the lateral. An artificial neural network (feed forward network with error back-propagation) is used to map the input properties (routine MWD data including gas shows, gamma and ROP) to the desired output properties (Young's Modulus, etc.). Figure 9 shows typical training results based on this approach.

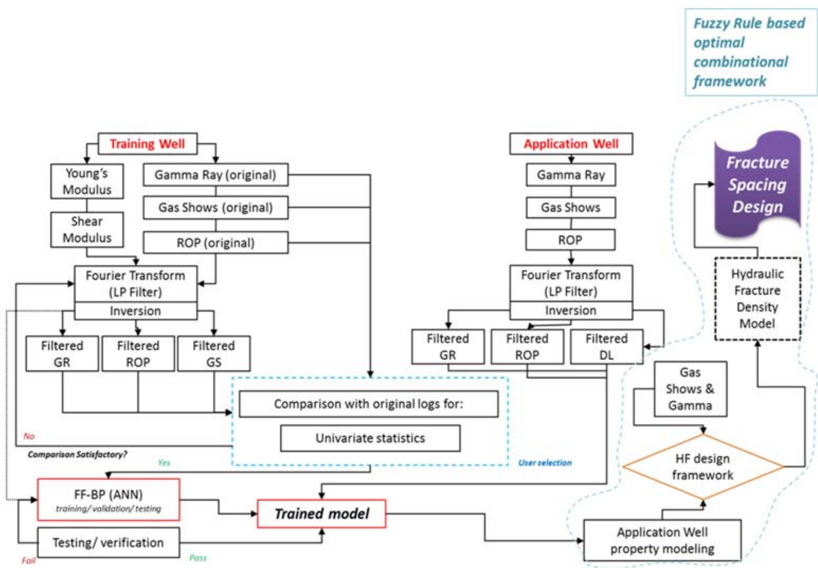

Figure 8: Fracture/ Cluster spacing design workflow.

While the broad framework on how the modeled rock properties and observed gas shows relate to naturally fractured intervals and the desired hydraulic fracture density (cluster spacing) so as to properly drain the laterals in question is very well defined, these definitions are semantic in nature which can be easily understood by an expert but requires some work for use within the context of our hydraulic fracture design workflow. In order to convert these approximate reasonings or relationships (rules) to usable mathematical relationships, we use a fuzzy

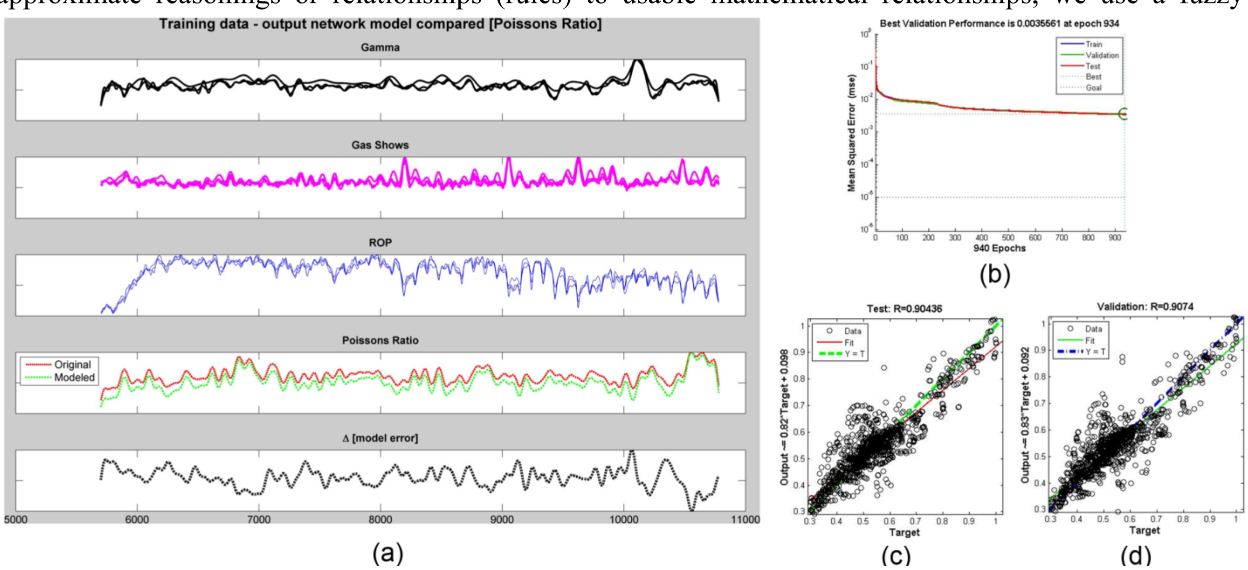

Figure 9: Subplot (a) is a composite plot showing inputs and the modeled output rock property and how it compares with the actual property. Subplot (b) shows a typical training run result for the ANN and (c) and (d) show the obtained cross-correlation for test and validation data subsets.

classification technique. At the same time, if production logs are available and the broad framework is well defined (such as highly brittle rock and high gas shows should lead to a lower modeled hydraulic fracture spacing density, etc.), we can try to generate the best possible model (and correspondingly, the best possible fuzzy classifier) to match the designed fracture density with the observed production behavior post completion. This is accomplished by using an evolutionary algorithm to minimize a predefined error function which tries to match the inverse of modeled fracture density with the observed cluster wise production. Figure 10 shows test results for candidate well located at a significant lateral offset from the training well with available scientific logging data used to train for the relevant models. The toe and the heal sections of the well showing higher mismatch correspond to zones where the wellbore transitions from the target shale layer to the overburden layer.

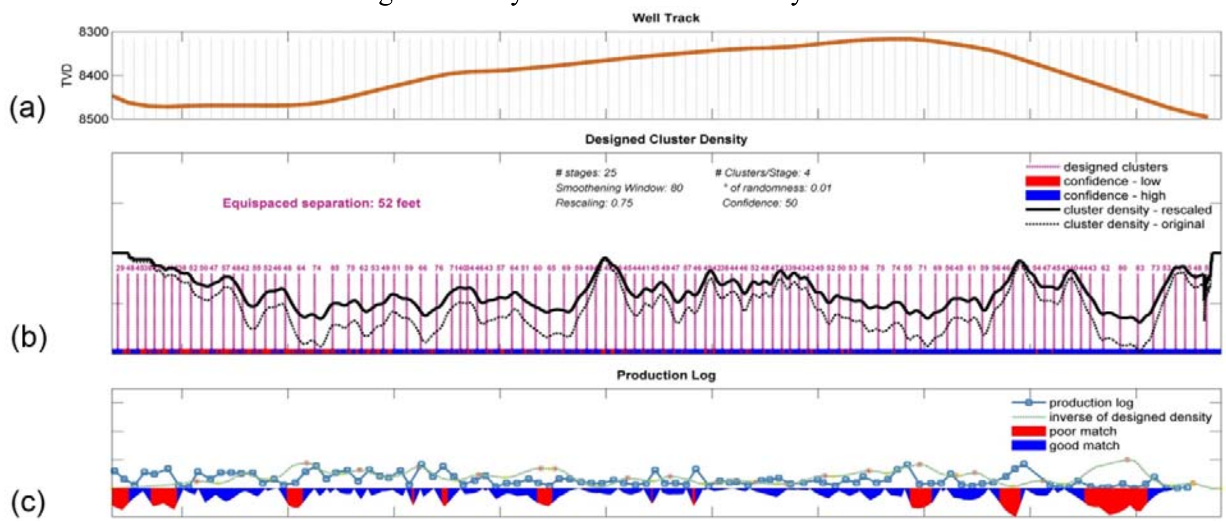

Figure 10: Typical result obtained for a candidate well using the hydraulic fracture spacing design toolbox. Subplot (a) shows the actual wellbore track (TVD vs. MD) and the placement of stages without optimization workflow. Subplot (b) shows the optimization result as obtained from the toolbox and (c) shows the comparison between the modeled density (inverted) and the observed production log behavior. We find that along most sections of the lateral, there is a reasonably strong match between the inverse of modeled density & high production contribution.

Based on the positive observations from preliminary tests, a modified workflow has been developed which utilizes multiple models for multiple zones within shale plays and based on the actual position of the well track, the relevant model is used for cluster spacing design. This becomes critical as changes in zones within the shale play can lead to significant changes in mineralogy and consequently impact the rock properties that are being modeled for spacing design. This workflow has shown very promising results and will be validated during planned blind tests in the field.

Conclusion

Sustainable shale gas development will require efficient operations and highly productive optimally spaced fracture stages along the entire horizontal wellbore. We have devised a hydraulic fracture stage (cluster) spacing design workflow and developed a Matlab based toolbox to help with hydraulic fracture design. Preliminary tests for multiple wells from different pads from the Marcellus play indicate good correlation between designed cluster spacing and post completion logged production. Actual field trials with designed completions are pending.

Acknowledgements

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