DEVELOPING ARGENTINA'S SHALE RESOURCES: COMPLETIONS ENGINEERING AND RESERVOIR ENGINEERING APPLICATIONS OF MICROSEISMIC DATA

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RESUMEN

Desarrollando los recursos de esquistos de la Argentina: La Ingeniería de Completación y la aplicación de datos de microsísmica en la Ingeniería de Reservorios

La combinación de recursos no convencionales de las cuencas Paraná, Chaco, Neuquén, Golfo San Jorge, y Austral-Magellanes de Argentina, exceden substancialmente sus reservas convencionales lo cual hacen de Argentina el primer país en Sur América en referencia a recursos esquistos recuperables con 27 mil millones de barriles de petróleo de esquisto (comparado con 58 mil millones de barriles en EE. UU.) Y 802 TCF de gas de esquisto (comparado con 665 TCF en EE.UU.) de acuerdo con los últimos estimados. Las dos zonas más fecundas en el Neuquén son la Vaca Muerta con 308 TCF y 16 mil millones de barriles y Los Molles con 275 TCF y 3.7 mil millones de barriles asegurando el liderazgo Argentino en la producción no convencional de petróleo y gas en Sur América. Con dichos vastos recursos en mano es imperativo desarrollarles de la forma mejor y más eficaz en referencia a costo y tiempo. La tecnología más poderosa y adecuada para lograr dichos objetivos es el monitoreo micro sísmico, el cual ofrece una descripción de depósito sin paralelo al igual que una enorme cantidad de conocimiento y la garantía de una fuente de energía limpia, segura y barata.

El monitoreo micro sísmico puede usarse para aplicaciones de ingeniería de terminaciones al igual que ingeniería de depósito. Ejemplos provenientes de Norte América ilustraran como usar conjuntos de puntos micro sísmico para optimizar el desarrollo de la zona y el espaciamiento del agujero del pozo, el diseño de terminación del pozo, al igual que el calendario de tratamiento, reduciendo significantemente el tiempo de evaluación y acelerando el proceso de aprendizaje. Distinguiendo entre el Nivel de Roca Estimulada total (SRV), en donde se observó actividad micro sísmica y la parte del SRV que contiene las fracturas llenas con apuntalante, y las cuales por lo tanto producirán a largo plazo, nos permite definir un volumen de drenaje y calcular un sistema de permeabilidad cual puede ser utilizado para predecir niveles de producción. Para crear un modelaje de la red discreta de fracturas (DFN) que ocurren como resultado del tratamiento, la ubicación de eventos, y sus mecanismos focales se usan para calcular le geometría de cada fractura individual (largo, alto, y apertura) al igual que su orientación en el espacio, resultando en un DFN calibrado en medidas micro sísmicas (magnitud de evento, mecanismo focal), las propiedades de la roca del depósito tratado, y el nivel de fluido inyectado. Uso de apuntalante de material anivelado y basado en distancia para relleno en cada etapa produce una media longitud cual puede ser utilizada para determinar el espaciamiento ideal de agujeros. Integración adicional de data de bombeo y el calendario de tratamiento pueden ayudar a optimizar la duración de etapa y el espaciamiento de agrupaciones para así mejorar la complexidad y conectividad de red de fracturas creada, cual resulta en un drenaje más uniforme a lo largo del agujero. Basado en el DFN y SRV, un escalar tensor de permeabilidad puede ser calculado de el volumen de roca conteniendo actividad micro sísmica cuantificando la relativa mejora de permeabilidad causada por la estimulación hidráulica en cada

célula de la red al igual que su orientación y su geometría. En adición al escalar de permeabilidad, un sistema o sea permeabilidad masa puede ser obtenida por medio una evaluación de la dinámica espacio-temporal de los eventos micro sísmico, cuantificando así la habilidad absoluta de llevar hidrocarbonos dentro del sistema de fractura hidráulica y a través de la red de fracturas y de regreso a el agujero. Validando observaciones y predicciones por medio del estudio de data de producción de varios años demuestra una correlación disminuyente con el SRV total a lo largo del tiempo, mientras que la correlación con el SRV que contiene la red de fracturas llenas con apuntalante incremento, demostrando la definición de un volumen de drenaje a largo plazo definido por una red de fracturas llenas de apuntalante. La excelente correlación en cada etapa entre la permeabilidad del sistema calculada y el registro de producción de cada etapa nos da
confianza que data micro sísmica puede ser utilizada para optimizar la terminación de agujeros, ayudar a definir diferentes niveles de drenaje durante las diferentes etapas y durante la vida de el pozo, y ultimadamente predecir niveles de producción.

MICROSEISMIC MONITORING

Microseismic monitoring today provides important information to characterize the reservoir and drive field development, wellbore completion, and treatment design strategies. Partially due to the rapid development of shale plays in the past decade, it has become an accepted industry practice and standard to monitor hydraulic fracturing treatments of unconventional reservoirs. Microseismic monitoring has helped greatly to educate geoscientists and engineers about what hydraulic fractures look like in these heavily naturally fractured ultra-low permeability formations. The fracture created during hydraulic stimulation greatly deviates from the planar bi-wing textbook example and is more accurately represented by a highly complex network of fractures instead. Mapping of microseismic event locations suggests that multiple rock failure mechanisms could be in play during the treatment. The complexity of the network is further enhanced by the interaction of the perturbed stresses with existing fractures in the reservoir relative to the unperturbed *in-situ* stress state of the reservoir. Pre-existing natural fractures, if favorably oriented for shear failure, will activate at lower stresses than the creation of new fractures requires (Neuhaus *et al.*, 2013; Williams-Stroud, 2008). Microseismic data and source mechanisms will constrain not only the location of fractures but also their geometry and orientation in space resulting in a Discrete Fracture Network (DFN) that serves as important input for reservoir simulation and from which the total rock volume that was affected by the treatment can be calculated. This can then be further refined by placing proppant in the DFN to help discern between the part of the Stimulated Rock Volume (SRV) that is expected to contribute to production in the long term and the part of the SRV that showed microseismic activity but might not contain hydraulically connected features or fractures that are expected to close on themselves over time due to the absence of proppant.

DATA ACQUISITION

Three methods are commercially available to record microseismic data: wellbore data acquisition with first break picking, and surface and near surface monitoring with beamforming imaging. Downhole (wellbore) monitoring consists of deploying a string of usually 8 – 40 three component geophones in the vertical section of a wellbore close to the area where microseismic activity is expected to occur, often being supported by a second string of geophones in the horizontal section where possible. P- and S-wave arrivals are recorded and first break picking is used to locate the microseismic events. Downhole acquisition can be very accurate in terms of event locations when the observation array is within close proximity to the microseismic events. However, the limited aperture 1-D array allows event location accuracy to deteriorate rapidly with distance, depending on geological complexity and event magnitude. Downhole monitoring can introduce a bias in the energy received by the monitoring array due to the location of the geophones relative to the microseismic events. Furthermore, placement of the geophones in the wellbore does not allow for detection of lateral polarity changes of the seismic wavefront limiting the opportunity for inverting for event source mechanism (Nevarez and Neale, 2009; Williams-Stroud, 2008; Seibel *et al.*, 2010; Baig and Urbancic, 2010).

Surface monitoring, as illustrated in Figure 1, consists of temporarily deploying hundreds to thousands of channels of conventional seismic equipment on the surface covering a large area over the treatment wellbore or pad. In order to determine microseismic event locations, surface monitoring utilizes full waveform processing and stacking. The processing that is employed

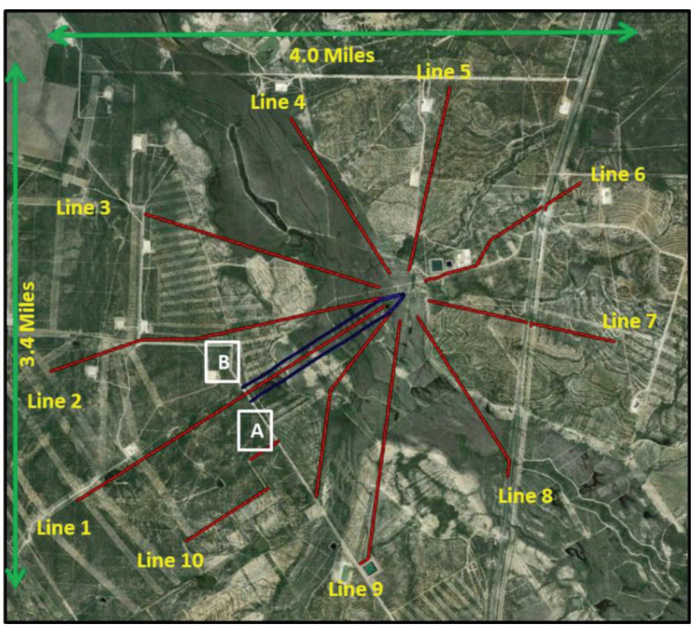

Figure 1. Surface microseismic monitoring array in the Eagle Ford Shale. Geophones are deployed on the surface along the red dotted lines. Wellbores can be seen in blue (Neuhaus and Rahimi Zeynal, 2014).

is similar to conventional 3-D seismic processing where a large number of seismic traces are preconditioned to control noise, beam form imaged and stacked to amplify the signal from the microseismic events. The array of geophones, which can be thought of as a large dish microphone, can be computationally pointed at target locations, which is referred to as beam forming, a type of migration also commonly used in conventional seismic imaging (Duncan and Williams-Stroud, 2009; Nevarez and Neale, 2009). The high fold, wide azimuth, and large aperture geometry of the monitoring array provides a consistent imaging resolution under the entire array and provides a high-confidence estimate of event magnitude. Another advantage compared to single well downhole monitoring is the capability to determine source mechanisms. The broad areal coverage records the polarity changes of the seismic wavefront as it arrives at the surface which can be inverted to obtain the strike, dip, and rake of the associated failure plane (Williams-Stroud 2008).

Combining the best attributes of downhole and surface monitoring, near-surface monitoring is a permanent installation of geophones in shallow purpose-drilled boreholes, as shown in Figure 2. To ensure optimal coupling with the earth, the geophones are usually cemented in place in groups deployed at depths of 150 – 300 ft, depending on the near surface geology and the noise environment. A near-surface array of geophones provides imaging capability that is both technically and commercially superior to both surface and downhole monitoring overcoming the principle limitations of both techniques. Background noise is substantially reduced by several orders of magnitude, improving event detection thresholds and location accuracies which allows for a significant reduction in the number of recording geophones while maintaining the seismic inversion capability of a surface array. An additional advantage is that a single near-surface installation can be as large as needed to cover multi-pad to full acreage positions in a play (Nevarez and Neale, 2009).

MAGNITUDE CALIBRATED DISCRETE FRACTURE NETWORK

After microseismic events have been located, a magnitude-calibrated Discrete Fracture Network (DFN) is modeled onto the microseismic pointset in two steps. The basic assumption is that every event is representative of a fracture, which can be modeled and is centered on the event. Through source mechanism analysis, strike and dip of the failure plane are identified for each individual event. The geometry of each individual failure plane is then determined through the magnitude of an event incorporating rock and fluid properties resulting in a DFN shown in Figure 3. In order to obtain length, height, and aperture of the fractures a methodology incorporating the magnitude of a microseismic event, the rigidity of the reservoir rock, the injected fluid volumes, and, if available, fluid efficiency is employed. From the moment magnitude, the seismic moment can be calculated, which depends on the area of the failure plane, the displacement along the plane, and the rigidity of the rock. Assuming that the total detected seismicity is directly related to the injected fluid volume and that the change in volume is completely accommodated by the seismic failure, minus leak-off, if such information is available, the calculated fracture volume should equal the injected fluid volume. Since the seismic energy that was recorded during a treatment and subsequently located as discrete events is usually only a fraction of the total emitted energy, the two volumes described above rarely match. In order to account for any undetected microseismic event population, such as tensile failure emitting quickly attenuating low frequency signal, or microseismic events with a signal below the detection threshold, a scaling factor is introduced. Each variable defining the geometry of the fracture is then recalculated so that the fracture volume matches the injected fluid volume for the calibration stage (McGarr, 1976; Kanamori, 1977; Bohnhoff *et al.*, 2010; McKenna, 2013).

PROPPANT PLACEMENT AND PROPPED STIMULATED ROCK VOLUME

Estimating the propped half-length is performed by filling the DFN with proppant from the wellbore outward on a stage by stage basis. The packing density of the proppant is variable and can be adjusted based on the specific gravity of the proppant and available frac models. Proppant filling is constrained by tortuosity of the flow path by allowing only a fraction of the proppant to populate fractures intersecting the prevalent failure plane azimuth at high angles. The

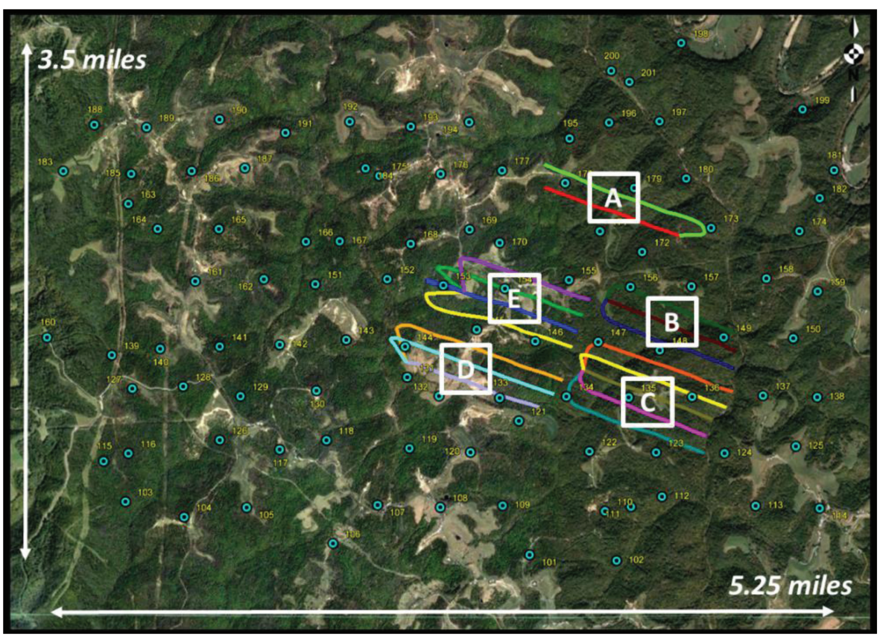

Figure 2. Map view of permanent near surface microseismic monitoring array in the Marcellus Shale. Strings of geophones are deployed at various levels in shallow boreholes illustrated as blue dots. Wellbores can be seen as colored lines (Neuhaus *et al.*, 2013).

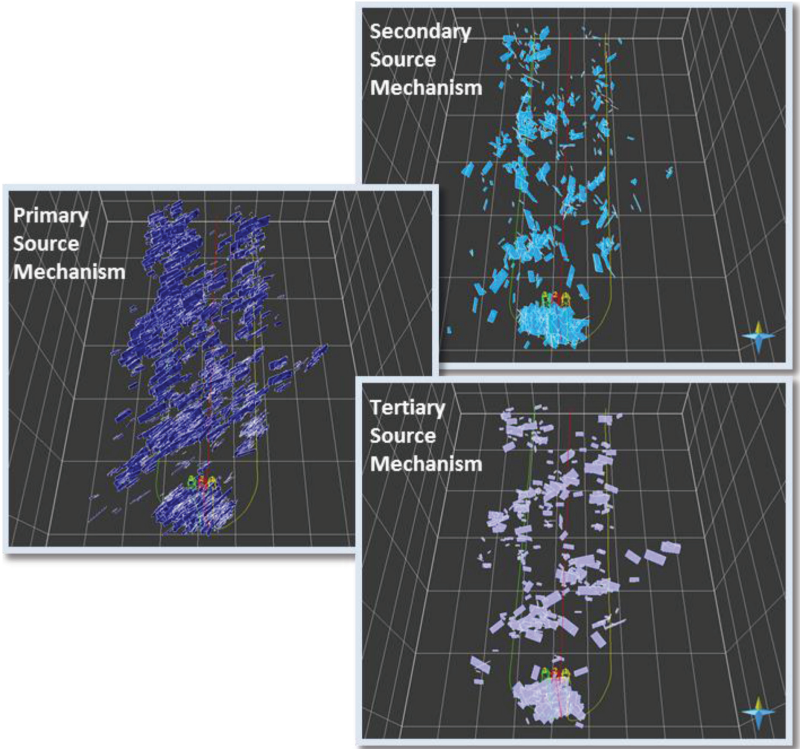

Figure 3. DFN modeling. The orientation of the fracture planes is determined by the source mechanism of the microseismic event. In the illustrated case, the total DFN consists of three fracture sets obtained from three different source mechanisms.

fracture volume inside the respective stage DFN is filled with proppant until all proppant that was pumped is accounted for to obtain the proppant filled fractures of the total M-DFN, as seen in Figure 4. Estimated propped half-lengths are then determined in a wellbore-centric coordinate system by breaking up the proppant filled fracture distances into a perpendicular horizontal, a parallel horizontal, and a perpendicular vertical component with respect to the corresponding stage center, as seen in Figure 5 (McKenna and Toohey, 2013).

In order to calculate the total Stimulated Rock Volume (SRV), a three-dimensional grid is applied to the total DFN. Every grid-cell containing a non-zero fracture property is included in the SRV. The total SRV is dependent on the size of the model cells and can be adjusted based on known reservoir flow properties. It represents the total rock volume that was affected by the treatment. In order to discern between the part of the SRV that is assumed to be drained over the lifetime of the wellbore and the remaining part of the SRV, the grid is applied to the proppant filled DFN as well. The subset SRV that is calculated from the part of the DFN containing proppant then represents the propped SRV that is expected to contribute to production in the long term, as illustrated in Figure 6. Based on the DFN and the SRV, a permeability scalar can be calculated for the rock volume containing microseismic activity quantifying the permeability enhancement due to the treatment in one cell relative to the other cells in the SRV (Oda, 1985). The full tensor is calculated from the total number of fractures in an individual grid cell, based on the fracture orientations and sizes.

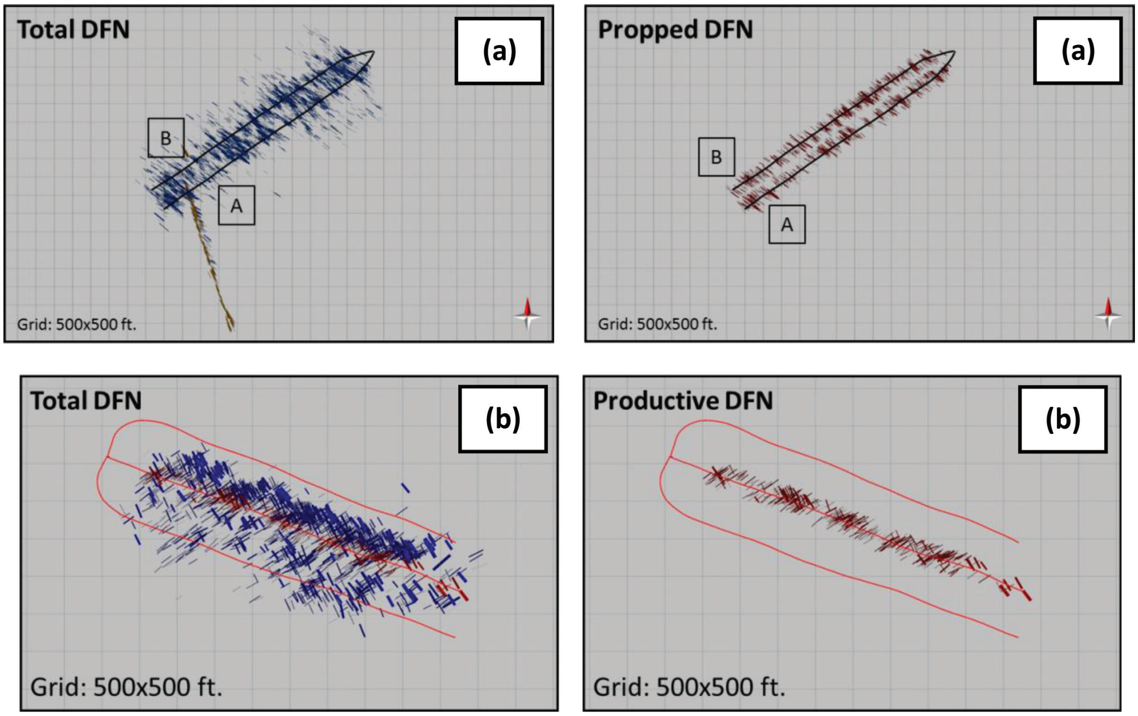

Figure 4. Total DFN and Propped DFN for Eagle Ford (a) and Marcellus (b) examples (Neuhaus and Rahimi Zeynal, 2014; Neuhaus *et al.*, 2013).

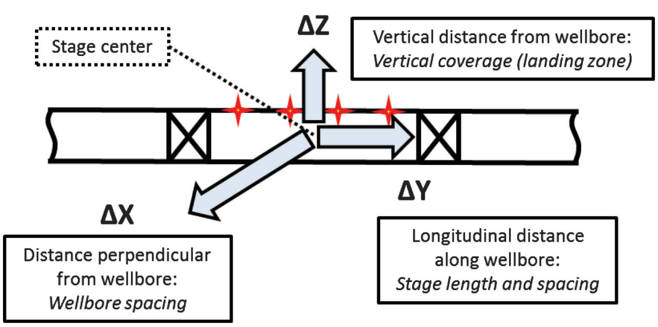

Figure 5. Fracture network growth analysis in wellbore centric coordinate system.

A calibrated DFN model can also be used to determine the effect of changes in treatment parameters, such as flow rate, treatment pressure, and volume of fluid pumped as well as completion parameters such as stage length, number of perforations, and perforation cluster spacing, in order to optimize the hydraulic fracture design. A Marcellus case study (Neuhaus *et al.*, 2013) for example illustrated that varying stage length shows the highest potential in cost savings in terms of completion parameter optimization.

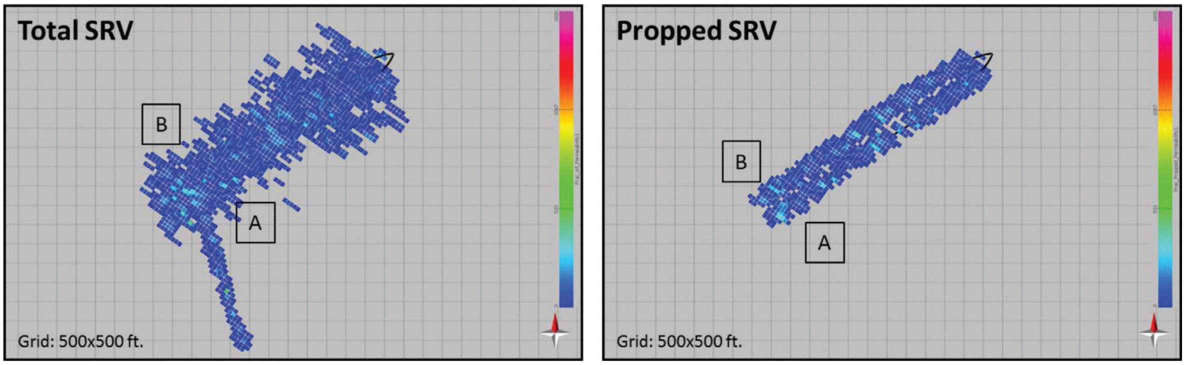

Figure 6. Total SRV and propped SRV for wells A and B in the Eagle Ford Shale. Total SRV can be seen on the left side, propped SRV can be seen on the right side. The propped SRV represents the part of the microseismically active rock volume that is related to proppant filled fractures and therefore long-term production.

WELLBORE SPACING

From the propped DFN shown for the Eagle Ford examples in Figure 4a an average propped half-length of about 270 ft can be observed for both wells suggesting an ideal wellbore spacing of 540 ft. That means that the propped fractures from each well touch each other at the tip leaving no unpropped reservoir in between which is most likely a more conservative assessment. Comparing that to the propped SRV seen in Figure 6, which is the rock volume that contains proppant filled fractures representing the long-term drainage volume, we can see that the current wellbore spacing of 600 ft seems sufficient leaving only very small parts of the reservoir in between the wells that do not contain proppant enabled conductivity. However, wellbore spacing can not only be estimated by looking at the perpendicular component of the propped DFN but also by analyzing the fracture growth during the high viscosity proppant-laden gel phase of the treatment (McKenna, 2014). The perpendicular component of the outer extent of fracture network growth can be mapped with the injected fluid volume as seen in Figure 7. The blue curve is generated by running a moving average window through the microseismic data for all stages sorted by elapsed fluid volume which identifies the center of gravity of the fracture network front in the perpendicular direction towards adjacent wells throughout the treatment. The graph shows how the low viscosity slickwater pad established the initial geometry of the fracture network while microseismicity concentrates closer to the wellbore after the systems sees the effect of the high viscosity gel that is being injected after the pad, indicating an increase in fracture width and near-wellbore complexity. Since the gel carries most if not all of the proppant, the microseismicity associated with the gel should give a good estimate of the proppant half-length. As seen in the plot, the average for the near-wellbore microseismicity occurring after the pressure diffusion is dominated by high-viscosity gel is about 270 ft which matches the half-length obtained from the proppant filled DFN.

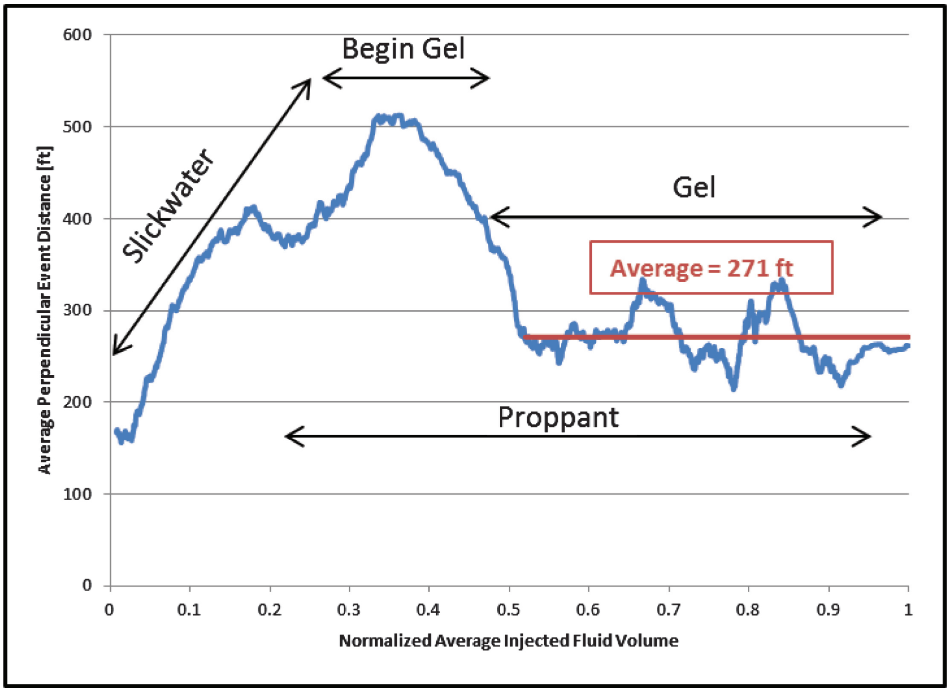

Figure 7. Fracture network growth with injected fluid volume. The blue curve represents the average perpendicular event distance, obtained from a moving average window run through the microseismic data, in relation to the average injected fluid volume.

For the Marcellus Shale example shown in Figure 2, the Productive-SRV workflow was performed on Pad B showing an average half-length of 320 ft from the wellbore, as seen in Figure 4b. Overall, the average productive SRV as indicated by the microseismic and proppant placement analysis is 33% for all three wells, as seen in Figure 8. It is evident that slightly reducing wellbore spacing could improve connectivity in the fracture network and increase production from currently undrained areas between wells (Neuhaus *et al.*, 2014).

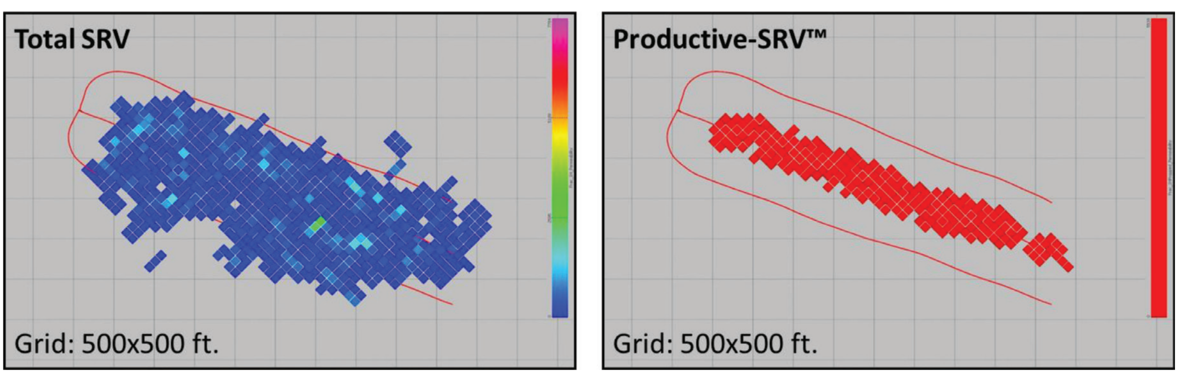

Figure 8. Productive Stimulated Rock Volume for Marcellus Example. The total DFN can be seen in blue in the upper left corner. The proppant filled portion of the total DFN can be seen in red in the upper right corner. From the total DFN the total SRV can be determined as illustrated in blue in the bottom left corner. The productive portion of the SRV due to proppant filled fractures is shown in red in the bottom right corner.

COMPLETION DESIGN AND VERTICAL COVERAGE

Comparable to the wellbore spacing analysis, an ideal stage length and spacing can be determined by measuring the longitudinal extent of the propped fracture network as well as analyzing the longitudinal fracture growth with the injected fluid volume. For the Eagle Ford case shown in Figure 4a, the numbers obtained from both techniques indicate an average overlap of 26% between stages towards the previously treated stage as well as towards the next stage, as illustrated in Figure 9. Further analysis of the microseismic data, however, shows that most overlap occurs close to the wellbore. Therefore, stage spacing and overall length may be decreased for increased connectivity and complexity of the fracture network more uniform drainage along the lateral.

Looking at height containment for the Eagle Ford case, the majority of the microseismic activity was contained within the Lower Eagle Ford with some upward growth into the Upper Eagle Ford. Both wells showed fairly symmetrical upward and downward growth indicating consistent treatment of the target zone as well as some treatment of the hydrocarbon-bearing sections of the Eagle Ford above the target depth.

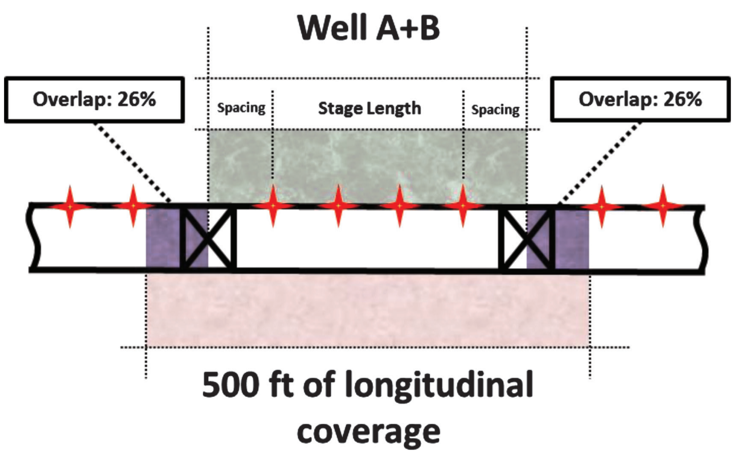

Figure 9. Propped microseismic coverage in pink compared to total stage length in green for Eagle Ford examples (Neuhaus *et al.*, 2014).

TREATMENT EFFICIENCY

The Eagle Ford study wells, seen in Figure 4a, were completed in a zipper-frac mode meaning that the wells were not treated individually from toe to heel one at a time but rather in an alternating way where equal number stages were pumped sequentially across the pad in a zipper-like pattern. This can often have the effect of a more complex and better connected fracture network between wells potentially providing more stable and uniform drainage (Neuhaus *et al.*, 2013). Fracture surface area can be used to quantify the magnitude of communication between the wellbore and the reservoir and evaluate the efficiency of the treatment. By plotting the cumulative fracture surface area for both wells against the cumulative injected fluid volume, as seen in Figure 10, it is obvious through the slope of the curve that treatment efficiency varies throughout the treatment. It is notable that for the trailing well in the zipper-frac completion (well A) treatment efficiency decreases towards the end of the treatment; while additional fluid volume is injected, not much additional surface area is generated as indicated by a decrease in slope and plateauing of the curve. This implies that the injected fluid volume may be reduced on the trailing well in zipper-frac'ing operations in this area.

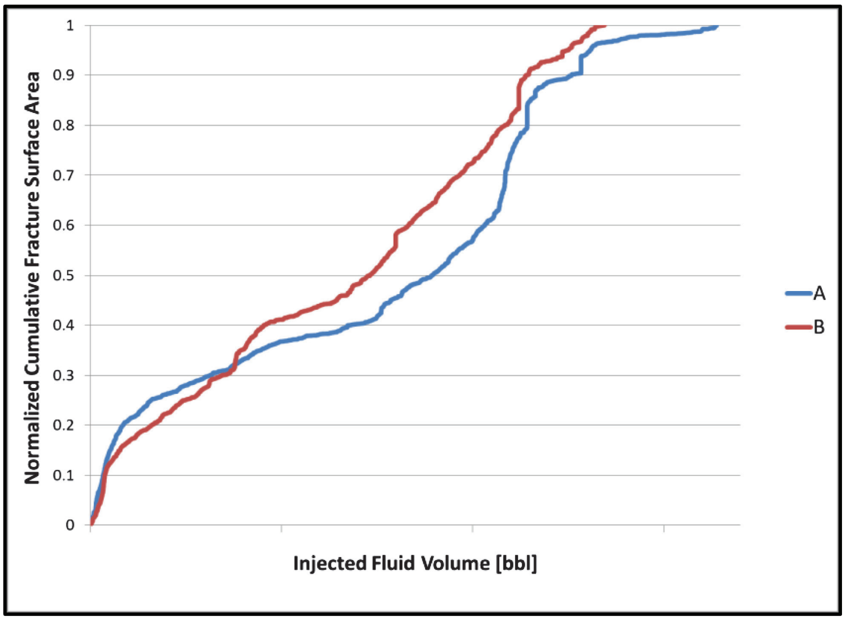

Figure 10. Cumulative fracture surface area generation to depict changes in treatment efficiency. Normalized cumulative fracture surface area can be seen on the y-axis. Injected fluid volume in bbls can be seen on the x-axis.

CORRELATION TO PRODUCTION

Research has shown that SRVs obtained from microseismic pointsets are correlated with actual field production (Rahimi Zeynal *et al.*, 2014). SRVs for Horn River projects in Canada were compared with 30 day production results to demonstrate the correlation of microseismic results with production data from a 7 well study pad. In order to truly understand the effects of the SRV variations on a well's future production a reservoir simulation model is necessary (Shojaei *et al.*, 2013). While there are numerous simulation models proposed for inflow of horizontal wells with multi stage fractures, they do not consider actual fracture network as input to the model. In ultralow permeability reservoirs, unless natural preexisting fractures and faults have been reactivated and hydraulically connected as a network structure, pore pressure change cannot transport very far away from the actual fractures. As a result, microseismic event cloud roughly corresponds to the real fracture network size, which offers a means to estimate the SRV (Mayerhofer *et al.*, 2010). The Horn River Study showed that larger SRVs result in higher well production.

In a different study, multi-year production data showed a decreasing correlation with the total SRV over time while the correlation with the Productive-SRV increases, illustrating the effect of different drainage volumes at different times in the life cycle of a well. Figure 11 shows cumulative production for six shale wells plotted against the total SRV. From production data ranging from 30 days to 3 years it can be seen that the correlation decreases as indicated by the correlation coefficient. Production is a dynamic process and unpropped fractures will close over time. Only proppant filled fractures will provide long-term conductivity which can be seen in Figure 12, showing the correlation between cumulative production and Productive-SRV. While the correlation is low for initial production, it increases over time outlining a reduction of the SRV contributing to production to the propped SRV.

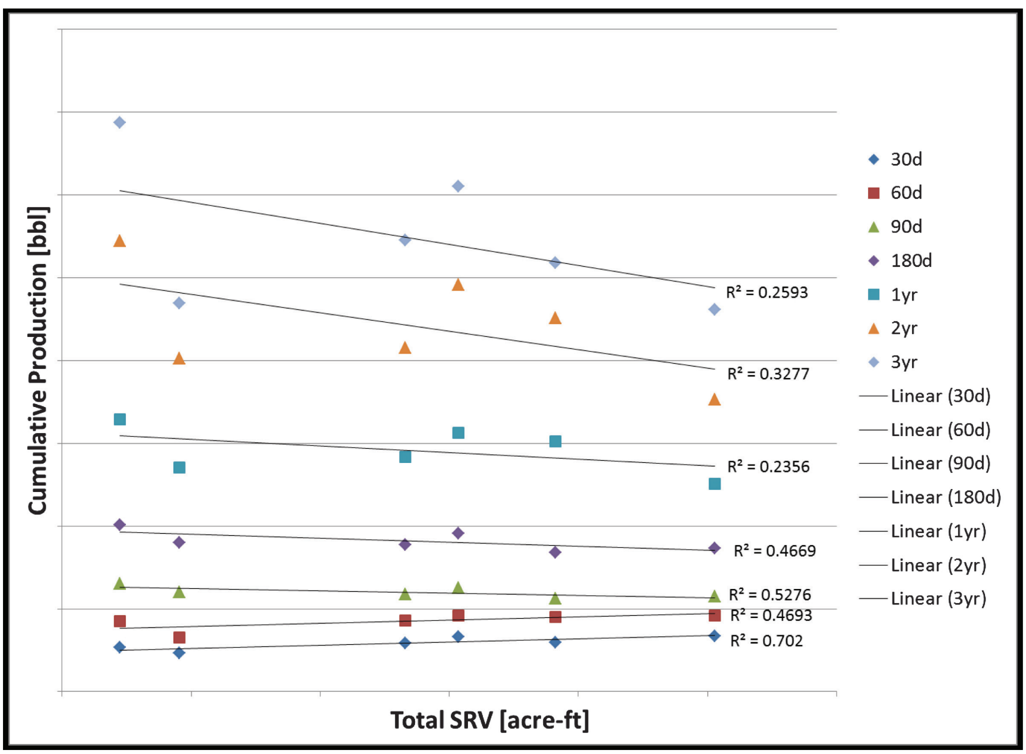

Figure 11. Correlation between total SRV and cumulative production decreasing over time.

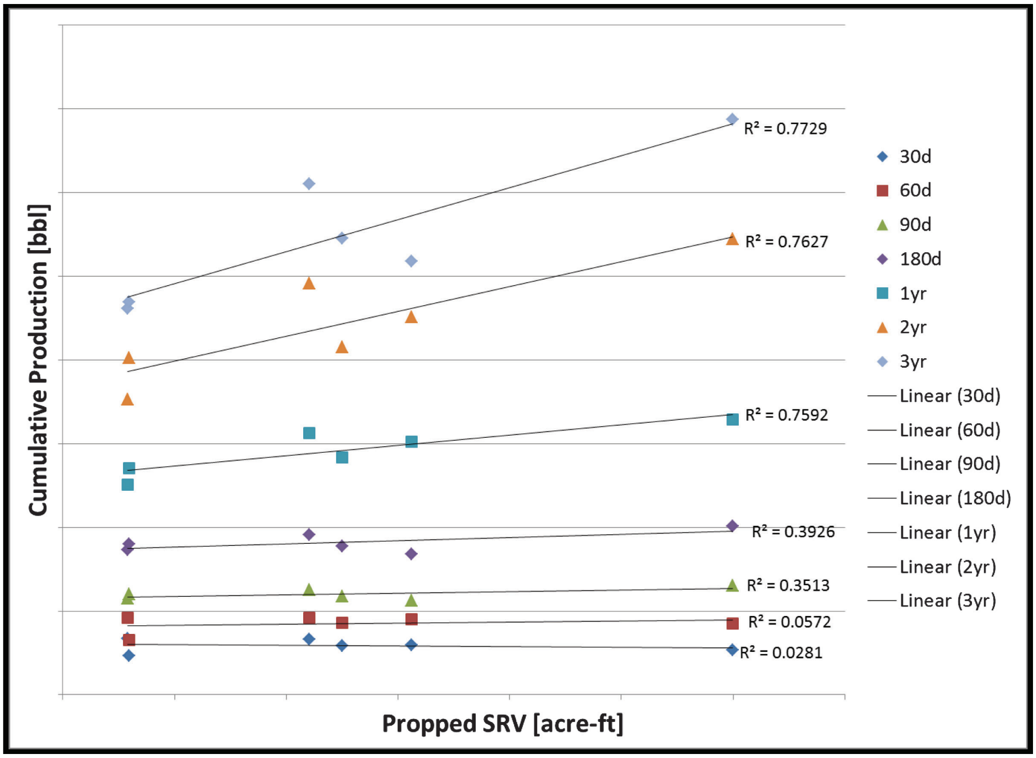

Figure 12. Correlation between propped SRV and cumulative production increasing over time.

CONCLUSIONS

Microseismic monitoring can be used as a reservoir characterization tool in order to further the understanding of hydraulic stimulation, evaluate the efficiency of a hydraulic fracturing treatment, and capture the variability within a certain field allowing the operator to adjust their completion and treatment design accordingly. With the use of source mechanisms, a magnitude calibrated Discrete Fracture Network can be modeled onto the microseismic events recorded during the stimulation of shale wells, representing the failure planes that were reactivated during the treatment. With proppant placement analysis, propped and unpropped parts of the DFN can be identified implying productive and non-productive parts of the total Stimulated Rock Volume regarding long term production. Propped half-lengths obtained from distance-based material balance proppant filling on a stage-by-stage basis can be used to determine the optimum wellbore spacing. Additional integration of pump data and the treatment schedule can help with optimizing stage length and cluster spacing in order to enhance complexity and connectivity of the created fracture network resulting in more uniform drainage of the reservoir along the wellbore. Research has shown a positive correlation between SRV and hydrocarbon production. Multi-year production data shows a decreasing correlation with the total SRV over time while the correlation with the SRV containing proppant filled fractures increased illustrating the definition of a long-term drainage volume defined by a proppant filled fracture network.

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