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A Case for Microseismic Surface Arrays in Texas?

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Summary

When imaging hydraulic stimulations, the industry requires alternative methods to acquire microseismic data when vertical wells are unavailable for downhole monitoring. Surface acquisition of microseismic data is one such method that can be used. This method may have lower costs in some cases when used for acquiring multiple wells on the same pad. It can also avoid impacting completions, in particular, during zipper stimulations when a downhole well is required for imaging. New processing techniques and acquisition methods in this field appear to show promising results for event detections and improved focal mechanism solutions (FMS) for fracture network classification.

Pioneer and numerous operators have shown that recording microseismic with a star-pattern surface array has proven to be successful in the Eagle Ford Shale Formation in South Texas. For Pioneer, this acquisition was paired with monitoring from a downhole array in a nearby vertical offset well. Both methods of observation recorded the overall stimulation and found a similar maximum stress azimuth and fracture orientation, which was also obtained from an oil base micro-imager (OBMI) tool. However, differences were noted in the event counts and fracture geometries, which are dependent upon the limitations of each acquisition method.

Acquiring microseismic data using surface arrays has proven in the past to be a challenge in the Midland Basin of West Texas. Pioneer Natural Resources (Pioneer) has previously used two vendors to record microseismic data in Midland and Reagan Counties using star- and patch-arrays at the surface. Both array types provided focal mechanism solutions (FMS) to help characterize the fractures and provide stimulation geometries, including average fracture length, height and azimuth. In one of these past jobs, Pioneer also acquired downhole along with the surface data. In this project, the patch- and nearby downhole-array recorded the same hydraulic stimulation and their microseismic datasets confirmed the same maximum stress azimuth. Yet, the same limitations of surface acquisition were apparent in both types of arrays, specifically the problem of very low event counts. It is suspected that the low event counts are due to energy attenuation in the shallow, high-velocity evaporites prevalent in the Midland Basin.

In an attempt to better understand the limitations of surface arrays in the Midland Basin, Pioneer along with two surface contractors (Dawson and NanoSeis) undertook a large scale project to better quantify differences between the downhole and surface methods as well as to test acquisition systems. These companies put together a large-scale (using four times the geophones of standard surface arrays) surface patch-array test program with the purpose of mitigating the shallow attenuation effects through signal enhancement via high fold, from an increased number of geophones. In this design, each patch was augmented with an inset array of 3-component geophones. This microseismic dataset was compared to one recorded by a nearby downhole array for the same project, and a portion of these data are shown and discussed in this paper. Beyond recognizing key similarities and differences in the microseismic attributes from the downhole and surface data in the context of the related stimulation, one of the most significant contributions of this test is that the data can be decimated to determine the minimum requirements for a successful surface acquisition of microseismic data in the Midland Basin.

Introduction

Microseismic monitoring of hydraulic fracture jobs has proven to be a useful tool for the oil and gas industry. Not only has it allowed for improved treatment designs in real-time, but it can also be used to help guide the optimization of well placements, spacing and completions (Fisher *et al.*, 2002; Maxwell, S.C. *et al.,* 2002; Fisher *et al.*, 2004; Cipolla *et al*., 2005; Mayerhofer *et al.,* 2005; Warpinski *et al.,*2005; Duncan and Lakings, 2006; Waters *et al.*, 2006; Daniels *et al.,* 2007; Vulgamore *et al.,* 2007; Barker, 2009; Waters *et al.*, 2009; Urbancic *et al*., 2011; Wessels *et al*., 2011; Baig, 2012; Kratz *et al*., 2012). It provides additional constraints for the calibration of fracture and reservoir modeling, such as fault interactions, geomechanics and attributes, and stimulation interactions. The bottom line is that it has been shown to improve production and net value.

While Pioneer includes microseismic monitoring in its development toolbox, we do recognize that there are costs associated with using downhole systems beyond contractor costs, including delaying stimulations and production while our tools occupy virgin wellbores. Finding suitable existing deep observation wells can be a problem for microseismic acquisition. When such deep observation wells are not available and the tools must be deployed in a horizontal well in the same zone as the stimulation, Pioneer has recognized that minor noise interference (and bias in data) from pumping and perforating operations may reduce the signal to noise (SNR) and degrade the quality of the microseismic data. In regions where there are limited offset lateral and vertical wells available, surface acquisition systems have been deployed as an alternative for monitoring microseismic (Duncan and Lakings, 2006; Diller *et al*., 2012). A surface array does not occupy wells and may only minimally disrupt completion operations.

A surface array can provide additional advantages over those from a traditional downhole array, including enhanced data products. Most importantly is that surface arrays provide potential cost savings when monitoring microseismic of multi-well stimulations, potentially lowering the overall monitoring cost per well. Additional benefits include data quality, where the entire wellbore(s) can be imaged from surface with a uniform and perceived limited tool bias affecting the XY event positioning. A surface array inherently provides improved XY positioning of the events, compared to those recorded by downhole tools (Eisner *et al.,* 2009; Johnston and Shrallow, 2011). This is due to the full azimuthal distribution of tools over the area of interest improving the array's aperture in XY. However, the greatly reduced array aperture in Z results in depth biases often found in data from surface arrays, which commonly is a source of decreased event depth resolution (Eisner *et al.*, 2009; Johnston and Shrallow, 2011). While hydraulic fracture network geometries and stimulated rock volumes can be calculated from both surface- and downhole-arrays, the FMS attribute is a standard deliverable from surface acquisition systems. This attribute is only available from downhole arrays when multiple observation wells are used during acquisition or from composite radiation patterns (Rutledge *et al.*, 2013), and even then there are still limitations to the attribute. An FMS provides additional information to aid in the discrimination between natural and hydraulic fracture networks, including maximum and minimum horizontal stress orientations, which are essential for future development plans. This measurement can be viewed as a "beach-ball", a three-dimensional visualization that represents the different types of rock slippage, dip-slip, strike-slip, and volume changes, depending on the orientation of the beach-ball in three-dimensional space (Sykes, 1967; Dziewonski and Woodhouse, 1983; Walter and Brune, 1993; Vavryčuk, 2007). The events' corresponding fault/fracture plane orientations can then be calculated and used to classify the fracture network (Brune, 1970; Walter and Brune, 1993; Rutledge *et al.*, 2004; Baig and Urbancic, 2010; Downie *et al.,* 2010; Warpinski and Du, 2010; Cipolla *et al.*, 2011; Wessels *et al*., 2011; Williams-Stroud *et* al., 2012; Kratz *et al*., 2012).

Common challenges for surface acquisition and processing include the cost of permitting and availability of permits early enough for logistical operations, availability of large scale equipment, surface noise (wind, culture, oil and gas related activities, etc), and reduced vertical resolution of event locations due to the inherent bias from installing all tools above the events. The results from surface commonly have lower event counts when compared to those from a downhole array, as well as limitations on imaging weak events below a magnitude of -2.0 to -2.5. Both acquisition types have their own limitations and bias that may or may not be appropriate for satisfying project-specific goals, therefore the decision on whether a downhole- or surface-array is to be used must be on a case-by-case basis (Diller and Gardner, 2012). It is no longer a question of either surface microseismic or downhole. The market is demonstrating this shift, as the downhole acquisition companies are now offering surface arrays and the companies who traditionally specialized in surface acquisitions are now offering downhole arrays.

Acquisition and advanced processing of surface microseismic today is offered by a number of service providers. The types of arrays that have been developed over the last 10+ years include the Buried Array and FracStar Array, both by MicroSeismic Inc. (MSI) (Duncan and Lakings, 2006), and the Patch Array that has been tested by several companies, such as NanoSeis, Dawson, Schlumberger, Magnitude and CGG. While these companies have proven the tool to be both cost-effective and able to increase the net-value of the resource play in many regions across the country and world, the Midland Basin of West Texas has had only limited success.

Background

Pioneer has had success with surface monitoring in the Eagle Ford Shale Formation of South Texas. In 2011, MSI deployed their FracStar surface array and Pioneer compared the results directly to those from a downhole array system of the same stimulation. This 14 arm FracStar consisted of 1,531 stations, located approximately 11,000' above the stimulation wells. The average perforation location uncertainty in the XY direction was 42' and Z was 58'. The downhole tool-string consisted of 12 stations anchored in a vertical observation well, with a recording distance that ranged from 2,500' to 4,700' away from the stimulation.

Both the surface and downhole microseismic results implied good frac containment within the Eagle Ford Shale, with the larger magnitude events of both datasets corresponding to one another temporally and spatially, and their fracture azimuths in agreement. These azimuths also correlated to direct natural fracture measurements made by an OBMI log of the stimulated well. The surface microseismic data determined the location of a possible fault, which correlated to a fault noted in the 3D seismic and OBMI log for the same well.

The surface data processing also provided a FMS for each high quality event. Mostly fracture modes II (in plane shear) and III (anti-plane shear) were interpreted along the length of the wellbore from the FMS, with no tensile events seen. The majority of these events occurred during pumping of the frac fluid, which could account for the component of crack activation motion shown by the FMS. These results suggest that there were limited effects from natural fractures during the hydraulic stimulation, and the cause of the events were likely mechanical, due to crack activation accompanied by fluid injection.

In West Texas, the Midland Basin has proved to be a challenge for most surface array types. Pioneer has collected several surface microseismic datasets for the Wolfcamp Shale Formation as far back as 2012, through both acquisitions and data trades. Fracture geometries and azimuths determined from these datasets were very similar for the Wolfcamp Shale Formation; however, event count was surprisingly low for all of these stimulations. In 2013, Pioneer recorded microseismicity from a hydraulic fracture stimulation of a single well in Midland County. This was done with two simultaneously recording acquisition systems: a surface patch array and a downhole tool-string in a neighboring horizontal well in the same zone, ~650' from the stimulation.

The downhole array consisted of 12 tools positioned along the horizontal portion of the wellbore, with several tool movements in order to remain across from the active frac position. This array type provides microseismic locations with well constrained horizontal positioning, yet greater uncertainty is expected in the Z direction for tractored phones. However, the downhole tools were pulled into the vertical portion of the well to better resolve event depths on some of the heel stages. The surface patch array consisted of 2,160 channels/traces (~25,000 geophones), divided into 45 patches distributed evenly across the area of interest. The location uncertainty trends inherent to this array type are almost the opposite from what is found with vertically deployed downhole array acquisition systems (Kidney *et al*., 2010). Data recorded by both acquisition systems confirmed that the stimulation being monitored had similar attributes on some stages; however, the surface data had in general more poorly resolved event positions as compared to the downhole system.

Known advantages of surface arrays held true for this stimulation example, such as the entire length of the wellbore was recorded with minimal instrument bias, therefore these event locations were well constrained in their XY position. One potential challenge encountered during the processing of this surface microseismic data likely stemmed from complications with the contractor's processing algorithms. These struggles could have contributed to the extremely low event counts, which also hindered the fidelity of the resulting fracture geometry interpretations.

Challenges for seismic acquisition in the Midland Basin of West Texas, commonly include subsurface energy loss, possibly due to interbed effects of high velocity layers. These shallow anhydrite/carbonate layers are known to have energy scattering effects. Signal attenuation is one potential source of decreased SNR, along with surface noise in a region active with oil production. Wind noise, culture and pump jacks are just a few noise sources that a surface array has to contend with. There are ways to improve SNR, such as implementing a noise test in the study area and using the results to optimize placement of the patches, moving the surface tools away from power lines and roadways, burying the array a few inches under the top soil, and increasing the number of geophones.

Pioneer, together with Dawson Geophysical and NanoSeis, developed a new hybrid-patch array with 93,000 geophones (compared to our previous contractor test with 25,000 geophones) in hopes of overcoming the subsurface signal attenuation of Midland Basin. This test includes a plan to decimate the dataset in order to quantify the minimum number of geophones sufficient for future surface acquisitions in this region.

Method

This new hybrid-patch array approach to record microseismic activity from the surface was designed with the assumption that the data acquisition parameters would go above and beyond what was needed to ensure the collection of high fidelity data, with a decimation test to follow in the final processing steps. This surface test was composed of three parts: patch array, 25 broadband 3-component stations, and a decimation test to determine the minimum requirements for successful acquisitions in the future. The patch array included 23 patches at 1,200' x 1,200', with 100' station interval spacing, and 24 single component geophones per station. These 93,000 geophones were placed 3-4" below the surface and covered with top soil to reduce surface noise. In addition to the single component geophones, 25 broadband 3-component seismometers were distributed throughout each of the 23 patches and hand-augured to shallow depths and precisely oriented in space.

Choosing the right area to assign to this patch array test was essential. We chose a hydraulic stimulation in the Midland Basin that already had downhole microseismic monitoring planned, so the surface array could be directly compared to downhole data. This stimulation was located in an area with representative noise levels found at other Pioneer stimulation locations, and was a six-well pad of all horizontal stimulations in various zones of the Wolfcamp Shale Formation. An initial noise study was performed in this area to determine the optimal location for each patch of geophones. 24-hours of cultural, weather and diurnal noise were recorded and analyzed for 49 test patch locations, 23 of which were chosen for the surface array.

Calibration of the surface velocity model and statics was completed at the start and end of the stimulation, with a "super-perforation" located at the toe of the well and a string shot at the heel. This ensured calibration of the surface data to the completions and to the downhole data. The surface array continuously recorded microseismic data during the majority of the six-well pad stimulation, for approximately 25 days. Microseismic data was also recorded with a downhole tool-string deployed in one of the six lateral wells. This downhole array captured 62 of the 210 stages recorded from surface. In addition to locating the microseismic events (using the methods of Kao and Shan (2004)), NanoSeis calculated the FMS for these events using their image-domain pattern recognition technique, which enabled FMS to be extracted from events of low signal to noise.

Results and Discussion

Final events from the surface array include only the highest quality and highest confidence locations, which are judged to be real events beyond a reasonable doubt, and thus also include associated FMS. The perforation location uncertainties were found to average 25' in the X and Y directions and 51' in depth. These are very comparable to those found by the downhole contractor, who reported an average X uncertainty of 23’, average Y of 31’ and Z of 13’.

Surface and downhole acquisition systems were able to record a significant amount of data and the results from one of the lateral stimulation wells are compared here. While the downhole data contained high resolution data with good fidelity and imaged low magnitudes (range of -0.5 to -2.6), it was normalized to represent similar quality parameters and stages monitored for comparison to the surface data. A lower magnitude cutoff of -2.4 was applied to the downhole data; in addition to only including their top confidence events, which removed ~30% of their final dataset. The top quality events from surface were those with an associated focal mechanism solution and had a magnitude range of approximately -1.0 to -2.0. Because the downhole recorded fewer stages on this lateral stimulation, the surface dataset was limited to only include those same 11 stages, for the purpose of doing a side-by-side comparison of the datasets.

Comparison of the microseismic event locations from both systems show the highest event density along the wellbore, with decreased event density further from the wellbore, and both recorded similar density patterns across the 11 stages (Figure 1). The surface and downhole events were temporally correlated to one another using a second-by-second matching algorithm, and from those results, the spatially closest pair were determined to be the same event recorded by both systems. As a result, >75% of these surface events were directly correlated to the downhole events. The other events that we could not correlate directly to a downhole event may have been beyond the listening distance capability of the downhole array. These event comparisons have high R^2 values when comparing their XY locations, while the Z correlation is more difficult to interpret due to the small range of depths being sampled (Table 1). Further analysis of the average positive and negative offset between the correlated surface and downhole events showed a bias in the X and Y positions of the downhole data towards the monitor well.

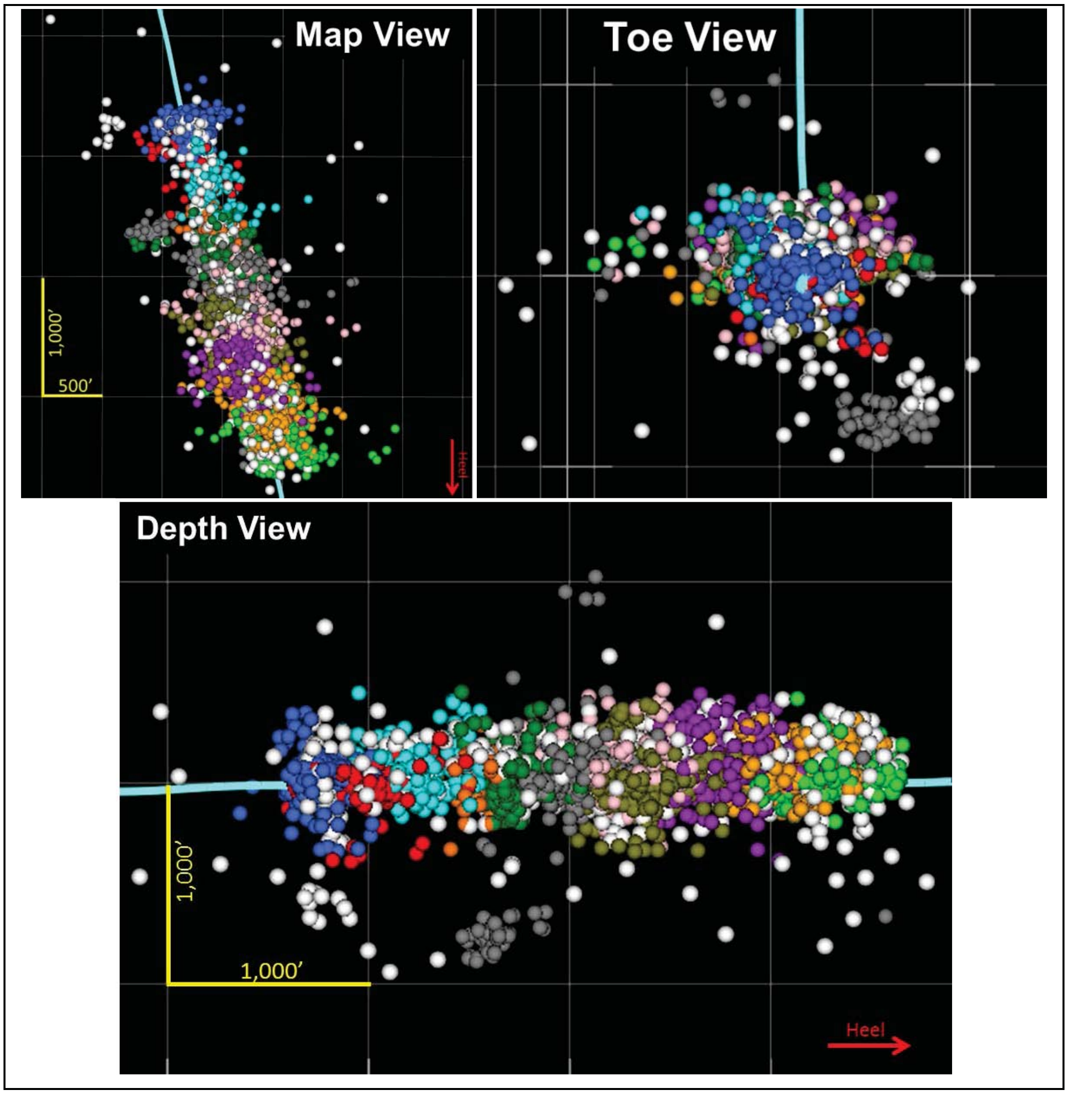

Figure 1: Microseismic events recorded by both a downhole acquisition array and surface acquisition array are plotted together, shown in three perspectives. Downhole events have been normalized to represent the same high quality confidence as the surface recorded events, and only the same 11 stages are shown in the direct comparison of the two acquisition systems. Similar event density patterns are seen from both datasets. Blue lines are wellbores, multi-colored dots represent microseismic events recorded and located from the downhole array and colored by stage; white dots represent microseismic events recorded and located from the surface array.

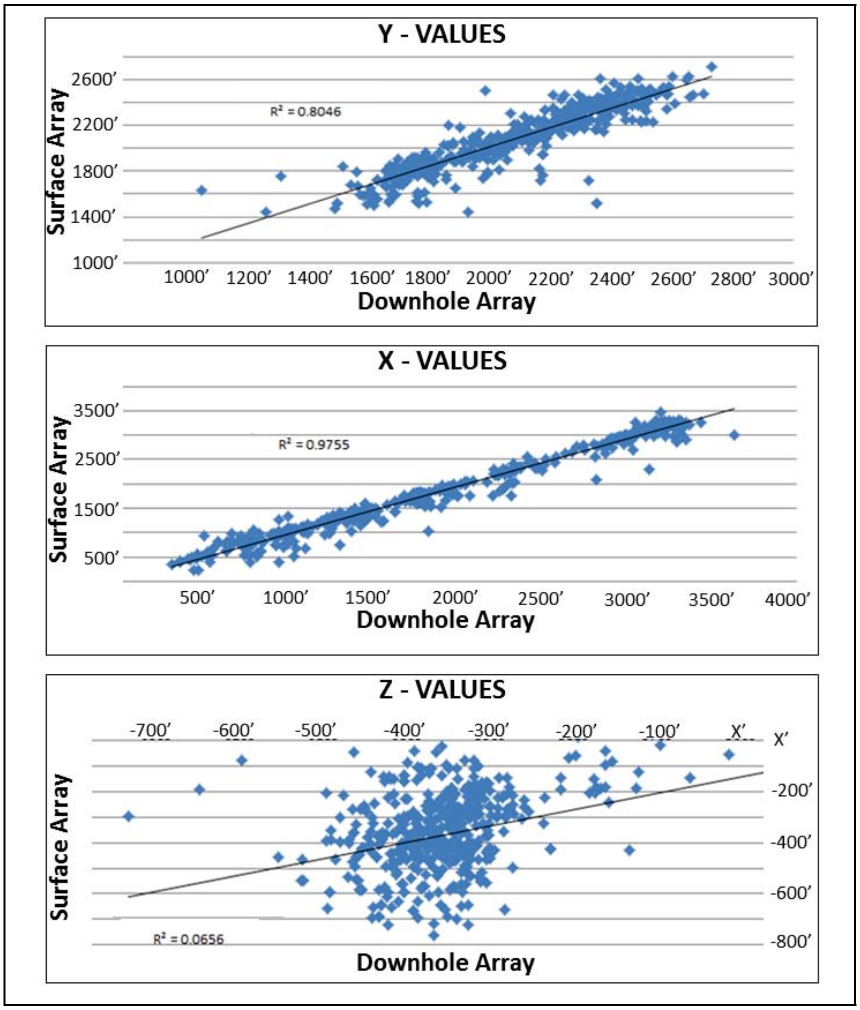

Table 1: Comparison of microseismic event locations as recorded from downhole (X axis) and surface (Y axis) arrays. The X- and Y-values represent a normalized coordinate system and the Z-values are compared using a common subsea depth datum, subtracted from "X ft". Their X, Y, and Z locations are directly compared and high R^2 values are calculated for the X and Y components, while the Z component shows a low R^2, which is expected due to the small depth range that is sampled in this subset of the two datasets. These two array subsets were created specifically for a side-by-side qualitative comparison from both arrays, and were normalized for magnitudes, confidence level and stages monitored.

Geobody volumes for these two datasets were calculated using a density field function in Transform software. Both sets of calculations retained the same parameters and the resulting volumes were similar, with the surface events' volume = 6.88 E^8 ft^3 and the downhole events' volume = 8.93 E^8 ft^3. While the event count from the surface acquisition is approximately 10% of the downhole event count, its geobody volume is 77% that of downhole events' geobody volume and exhibits the same general shape (Figure 2). The parameters used to calculate the two geobodies were kept the same, except for the threshold. This was increased for the surface event geobody in order to remove the effect of the outliers.

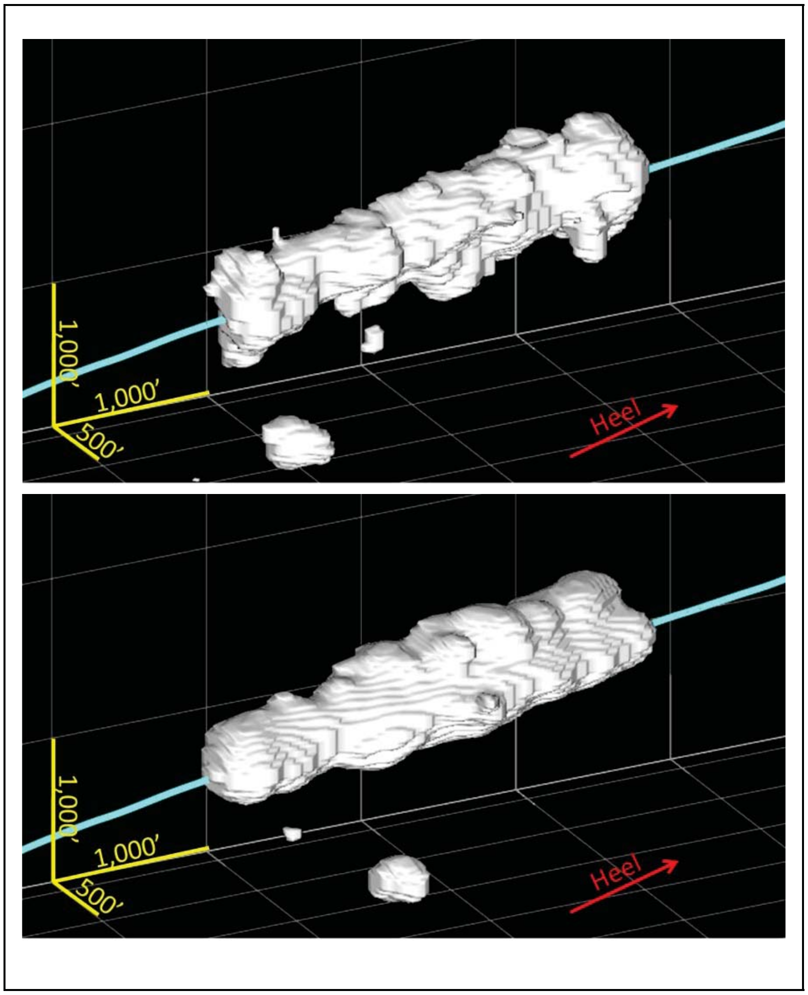

Figure 2: Comparison of microseismic geobody volumes from the surface events and downhole events. The only parameter used to generate this volume that differed from those used to calculate the downhole volume, was an increased threshold from 5% (downhole volume parameter) to 21% (surface volume parameter), which removed the added volume of the outliers. (Top) The geobody volume calculated for the high confidence surface events, filtered to show the same 11 stages as recorded by downhole, was 8.63 E^8 ft^3. (Bottom) The geobody volume calculated for the high confidence, downhole events filtered to show the highest confidence and removed the lowest magnitude events, was 6.88 E^8 ft^3.

The FMS determined from surface acquisition processing found 711 events across 14 stages, with the majority of the events classified as dip- and strike-slip, and only a minor amount of oblique motion. Both the strike-slip and oblique-slip mechanisms were found to be mostly contained above the stimulated wellbore, while the dip-slip plot above and below the well, each group showing a distinct orientation. Variation of the locations and preferred orientations for these types of FMS may be related to geomechanics or interaction with an offset horizontal stimulation on the same pad.

FMS can be plotted in another style by displaying their summed amplitudes in the form of a heat map showing event density (Figure 3). Fracture plane orientations along the entire wellbore can be interpreted from further processing such as this. While all of the FMS have two orthogonal nodal plane solutions, only one has been shown for each type in Figure 3. The vertical nodal plane orientation from the dip-slip events likely corresponds to regional maximum horizontal stress, while its orthogonal horizontal nodal plane most likely represents associated bedding-plane slip (Heidbach *et al.*, 2009; Rutledge *et al.*, 2013). Orientations of the oblique- and strike-slip nodal planes (Figure 3) may indicate pre-existing antithetic sets of natural fractures.

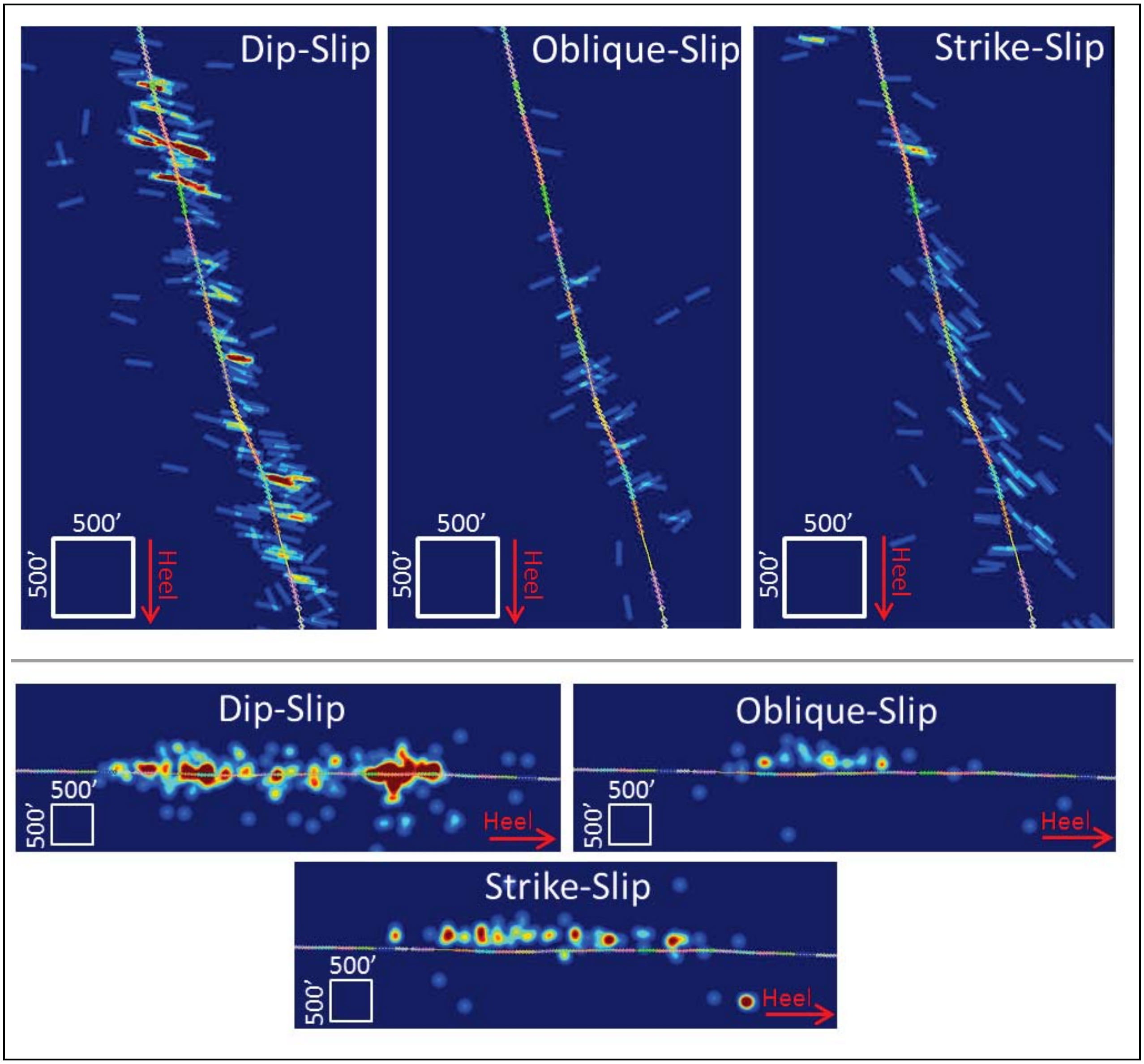

Figure 3: Summed amplitude display that represents microseismic energy density. The dataset is divided into multiple views only showing one focal mechanism solution type per image. Warm colors represent higher event density. The long axis of each individual event shape is parallel to a nodal plane from its corresponding focal mechanism solution. (Top) Images are map view with north up and (Bottom) images are depth view along the wellbore (Images modified from NanoSeis).

Conclusions

Surface microseismic has proven to be a cost-effective and technically sound tool in most regions. For example, Pioneer is just one of several companies that have had success when using a surface array to monitor microseismic activity within the Eagle Ford Shale Formation in South Texas. Surface monitoring of microseismic has been shown to be successful in some parts of the Permian Basin by other service providers and companies, however Midland Basin, specifically, has had mixed levels of success to date.

It is imperative that the industry finds success with surface monitoring in this basin, because there will be more hydraulic stimulations in the future with large multi-well pads. We are losing potential opportunities to image microseismic activity from offset zones in the downhole as field development continues. Placing downhole tools in a horizontal well that is in the stimulation zone may be a large source of noise that could interfere with the recording of high fidelity data. This type of acquisition offers an alternative to such downhole monitoring and can be very cost effective as it reduces the price per stage when monitoring more than one well at a time. In addition to higher cost from deploying downhole seismic tools, the risk of operational and production delays will also increase with the increased use of a wellbore prior to its completion.

Despite the decreased event depth resolution inherent to the surface acquisition system and lower event counts when compared to the downhole dataset, this hybrid-patch surface array tested in Midland Basin proved successful in acquiring similar frac geometries and similar geobody volumes. This surface array did not require rigging tools into a drilled well, therefore did not delay completions. It also provided a significant cost savings per stage recorded when comparing cost of the surface array to the downhole array.

The seismic signal was successfully doubled in Midland Basin with this new surface deployment of approximately four times the number of geophones, from that of our previous surface tests. Even in the presence of noise, over 700 focal mechanism solutions were calculated on the 14 stages. This attribute from surface arrays has the potential to discriminate between natural and hydraulic fracture networks, and characterize fracture plane orientation for future development plan guidance.

NanoSeis and Dawson will continue to test the limitations of this surface dataset to determine the minimum level of decimation required for a successful West Texas microseismic acquisition in the future. This decimation test will include the integration of the three-component broadband stations with the 93,000 single-component vertical geophones in hopes of determining a technically sound and cost-effective solution to monitoring frac treatments in Midland Basin.

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