AVBigger is Better – Hydraulic Fracturing in the Williams Fork Formation in the Piceance Basin*

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Introduction

The thick section of lenticular sands of the Williams Fork Formation in the Piceance Basin in western Colorado requires a special completion strategy for optimal economic development. The Williams Fork is composed of a 2,500+ ft stacked sequence of fluvial-channel and crevasse-splay sands interbedded with associated overbank and floodplain siltstone and shale deposits. Coals and tongues of marine sands are also present in the lower part of the Williams Fork.

This article provides results for microseismic fracture mapping of fracture treatments in five wells and 40 stages in the Mamm Creek Field in the Piceance Basin in Garfield County, as well as production and reservoir analysis associated with these large-volume fracture treatments.

Mapping Project Layout Considerations

Figure 1 shows the Gibson Gulch project setup, with two observation wells, the 13B-36-692 and 24C-36-692, located to maximize observation of the northwest and southeast fracture wings in all wells. The observation wells are located on the same pad as the five fracture treatment wells.

Hearing distances to average-magnitude microseismic events in Piceance Basin mapping projects range between 700 and 2500 ft and depend on many parameters, including noise level from same-pad operations, tool-to-casing coupling, cement-bond quality, pump rates, microseismic-moment magnitudes, stacking of tools (Shemeta et al., 2009). For this simultaneous operations project, hearing distances, as indicated by the green circles in Figure 1 was about 900 ft in the 24C well and around 1250 ft for the 13B well containing the stacked toolstring.

Perforation timing was performed for each stage in all of the 13A wells, stage 3 and 6 in well 24D, stage 4 in well 14D. Perforation timing refers to the practice of recording a perforation shot in the treatment well and measuring the difference between the time the shot is detonated and the time the event is detected by the geophone array (Warpinski et al., 2005). As the exact locations of the perforation events are known, this information can be used to calibrate a velocity model. This velocity model allows accurate calculation of the position of events detected during the fracture treatment. The calibrated (horizontal) layer velocities for various perforation shots are shown in Figure 2 and compared with (vertical) sonic log and (horizontal) cross-well tomography data.

Figure 3 shows the combined microseismic data for all stages in plan-view and side-view plots and also the treatment timeline. The quality of most of the recorded microseismic events is moderate-to-high at an average confidence level of 3.0 (on a scale between 0 and 5) (Zimmer et al., 2007). The wells closer to the tool string typically showed more recorded events and more precise event locations. General location errors for the mapping projects were relatively low with azimuthal error less than 10 ft, radius error less than 20 ft, and depth error less than 20 ft for more than 90% of the events.

Completion Details

The operator's completion strategy is to stimulate intervals averaging about 180 ft. The five wells were drilled to true vertical depths between 4300 and 6500 ft. Typically, between 16 and 28 perforations are shot, and injection rates of about 3 bpm/perforation are used to obtain diversion through a limited-entry technique. Treatments call for an average volume of 8000 bbls of slickwater and 160 klbs of 20/40 mesh Ottawa sand.

Fracture Azimuth for Well Placement

Measuring fracture azimuth for well placement is critical in the Piceance Basin, as fracture azimuth changes considerably. As shown in Figure 4, the fracture azimuths were very consistent between different stages at an average of N45°W, in a relatively narrow range between N38°W and N55°W. Figure 4 also shows a 10° rotation to the east with depth over the 1800 ft Williams Fork target interval. Fracture azimuth data for the nearby MWX site (Warpinski and Teufel, 1989) shows a rotation of as much of 30° over 2500 ft in the same direction.

Although the microseismic events spread laterally over 200-300 ft, this is not necessarily an indication that the created fracture system is complex. However, the microseismic data illustrated in Figure 5 shows the hydraulic fracture running in the stress azimuth direction, which is parallel to the natural fractures, and shows some indications of multiple parallel fractures, possibly indicating opening natural fractures. There are also many linear features aligned northeast-southwest, perpendicular to the main fracture orientation. These appear to be natural fractures undergoing shear in response to fluid movement orthogonal to the hydraulic fracture. Some of the planes are highlighted, but there are many more that can be identified by stepping through the treatment time. The inset shows the azimuth of the fractures highlighted in the figure. There were only a few natural fractures observed in XRMI™ imager log that have this orientation, but these may be the most important fractures for effective drainage.

Fracture Height Coverage with Limited-Entry Completion Technique

Injection rates of about 3 bpm/perforation were typically used in an attempt to obtain diversion with the limited-entry technique. Fracture-height growth is pronounced, and in many stages there is significant growth outside the intended target interval, resulting in large overlap between different fracture treatments. As shown in Figure 6, the intervals with lower ISIP gradients appear to coincide with the depths where hydraulic fractures overlap more.

The average fracture height for the project is 600 ft, with a minimum of 250 ft and a maximum of more than 1,000 ft. As shown in Figures 6 and 7, areas where ISIP gradients are lower correspond to depths where fracture overlap increases. It is not known whether an overlap in fractures results in higher long-term production response, and it may be worthwhile to look into this issue. If there is no benefit to the overlap in fracture height, fewer, smaller or lower-rate treatments may be considered in the areas where ISIP gradients are lower.

This is especially the case for the upper stages, which may be attracted to the lower ISIP gradients toward the top of the Williams Fork. The deeper stages show less overlap, and subsequent stages are possibly “pushed up” by stress shadowing of previous treatments.

Fracture Height and Half-Length vs. Volume

Treatments called for an average volume of 8000 bbl of slickwater and 160,000 lbs of 20/40 mesh Ottawa sand. Fractures are very long with an average half-length of 1200 ft, ranging between 750 for the smaller treatments and 1600 ft for the biggest treatments. Figure 8 shows that there is, as normally expected for relatively simple fractures, a good correlation between the fracture-treatment volume and fracture half-length. Note that the fracture half-lengths are reported for the fracture wings that could be fully measured and that there is no reason to believe fractures are asymmetric. For purely radial fracture growth without leakoff, the fracture radius is proportional to the volume pumped to the power 4/9. For perfectly confined fracture growth, half-length becomes proportional to the volume pumped to the power 4/5. In the log-log plot of half-length (in feet) vs. pumped volume (in bbl), the relationship between half-length and volume is:
$L_f = 1.46V^{0.74}$

Height, plotted vs. volume in Figure 9 also shows a good correlation between the fracture treatment volume and fracture height. In the log-log plot of height (in feet) vs. pumped volume (in bbl), the relationship between half-length and volume is:
$H_f = 6.75V^{0.51}$
Please note that the combination of the half-length and height relationships with volume do not comply with the law of conservation of mass, possibly due to the fact that half-length and height measurements are underestimated during pumping, when microseismic noise levels were higher.

Comparison of Production Results

Impact of larger fracture dimensions on production response has been found to be significant. Well EURs and production response have improved dramatically as a result of the larger hydraulic fracture treatments. In one example, on a two-well pad with wells with similar geologic characteristics, the well fraced with the larger water volumes have an average EUR of 1.25 BCF versus 0.7 BCF for wells completed with the smaller water volume. In another example, three adjacent pads with a total of 20 wells had 9 wells fraced with larger water volumes and 11 wells fraced with smaller water volumes. As shown in Figure 10, the average EUR for the larger water-volume wells is 1.4 BCF versus 0.8 BCF for the smaller water volumes.

In a different study of Piceance fracture stimulation, Salas et al (2008) showed that wells stimulated with more than 3000 gal/foot gross pay show a 6-month production increase of about 70% in comparison to jobs with an average of 1700 gal/foot gross pay (Figure 11).

Conclusions

- Larger-volume fracture treatments lead to longer fracture half-lengths and heights, and result in improved production performance.
- Fracture-height growth is attracted to areas where ISIPs are lower. There is significant overlap in fracture-height growth between various fracture-treatment stages.

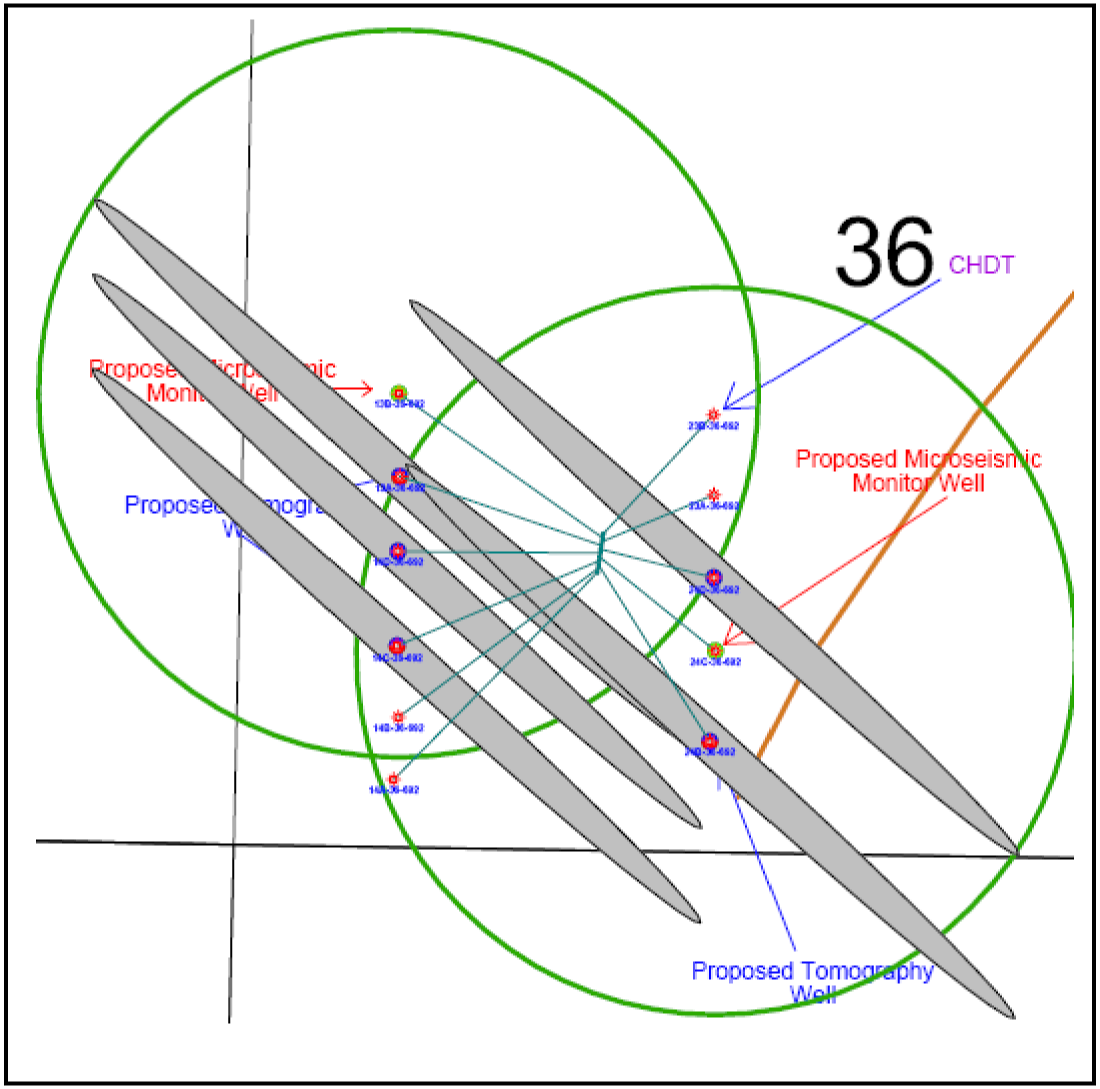

Figure 1. Gibson Gulch fracture mapping project setup.

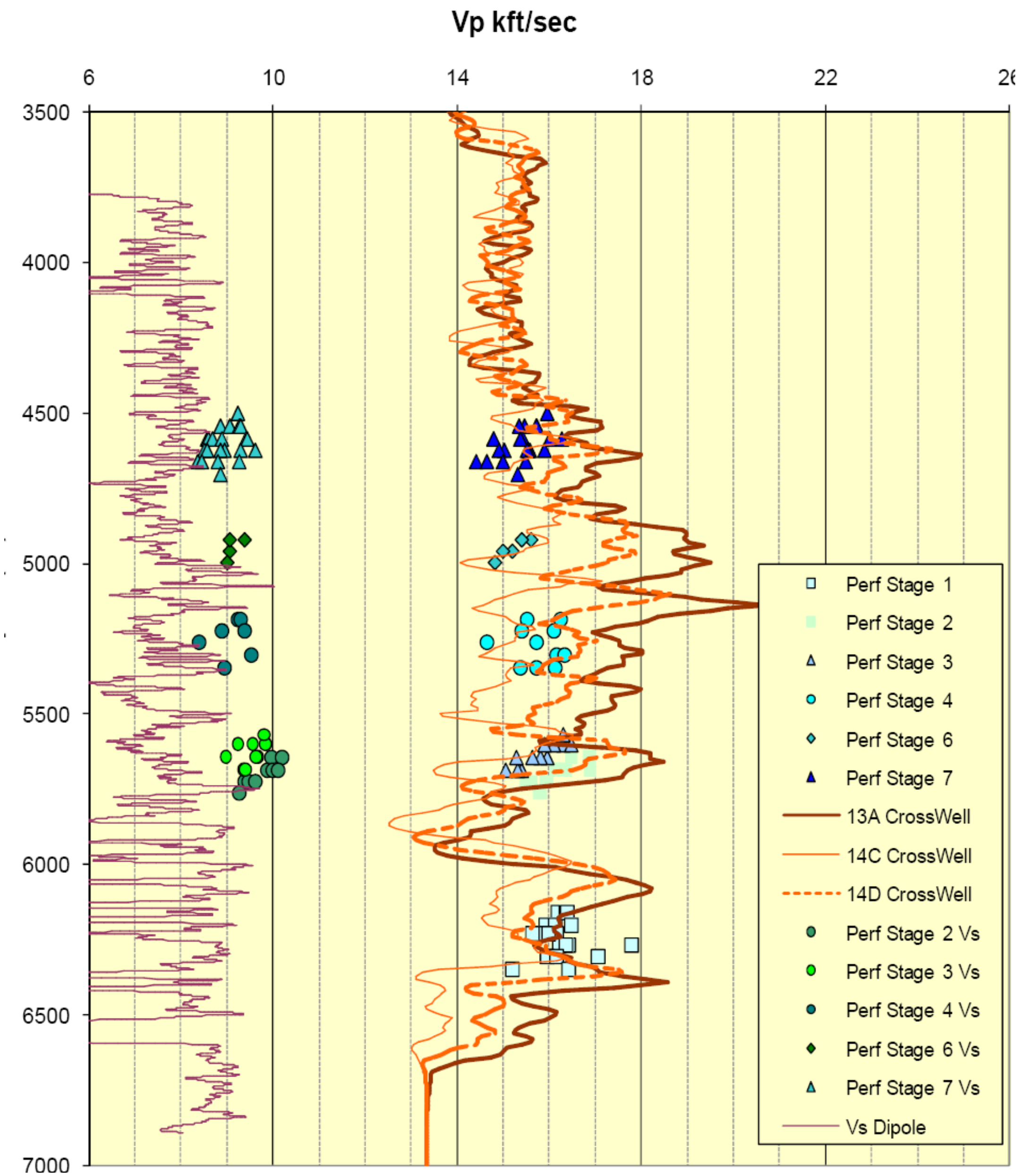

Figure 2. Velocity model comparison for perforation timing and cross-well tomography in well 13A. In general, P-wave velocities from perf timing are slightly smaller than velocities from cross-well tomography.

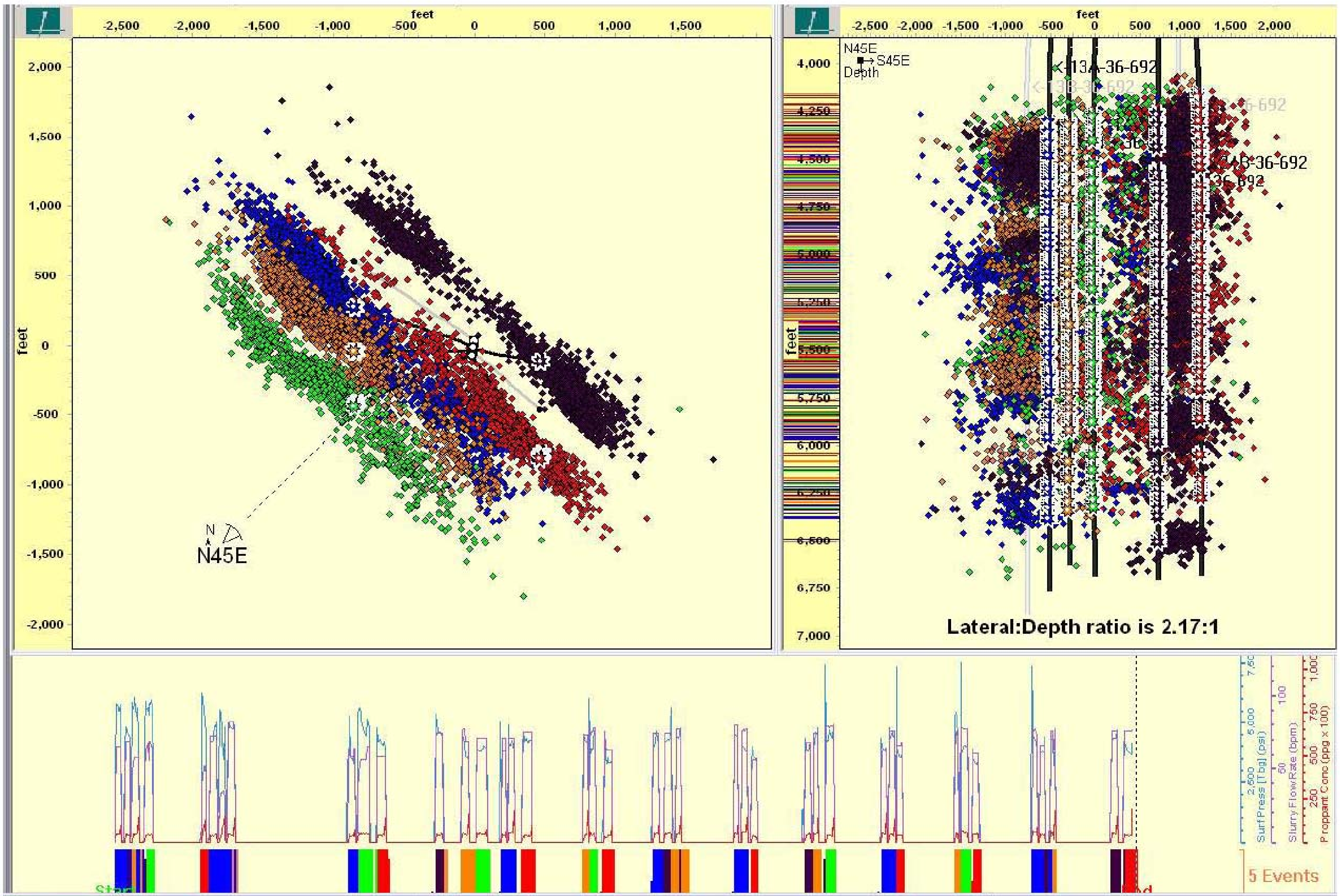

Figure 3. Map view, side view, and treatment timeline for all stages and all wells for the Gibson Gulch project. Events are colored by well.

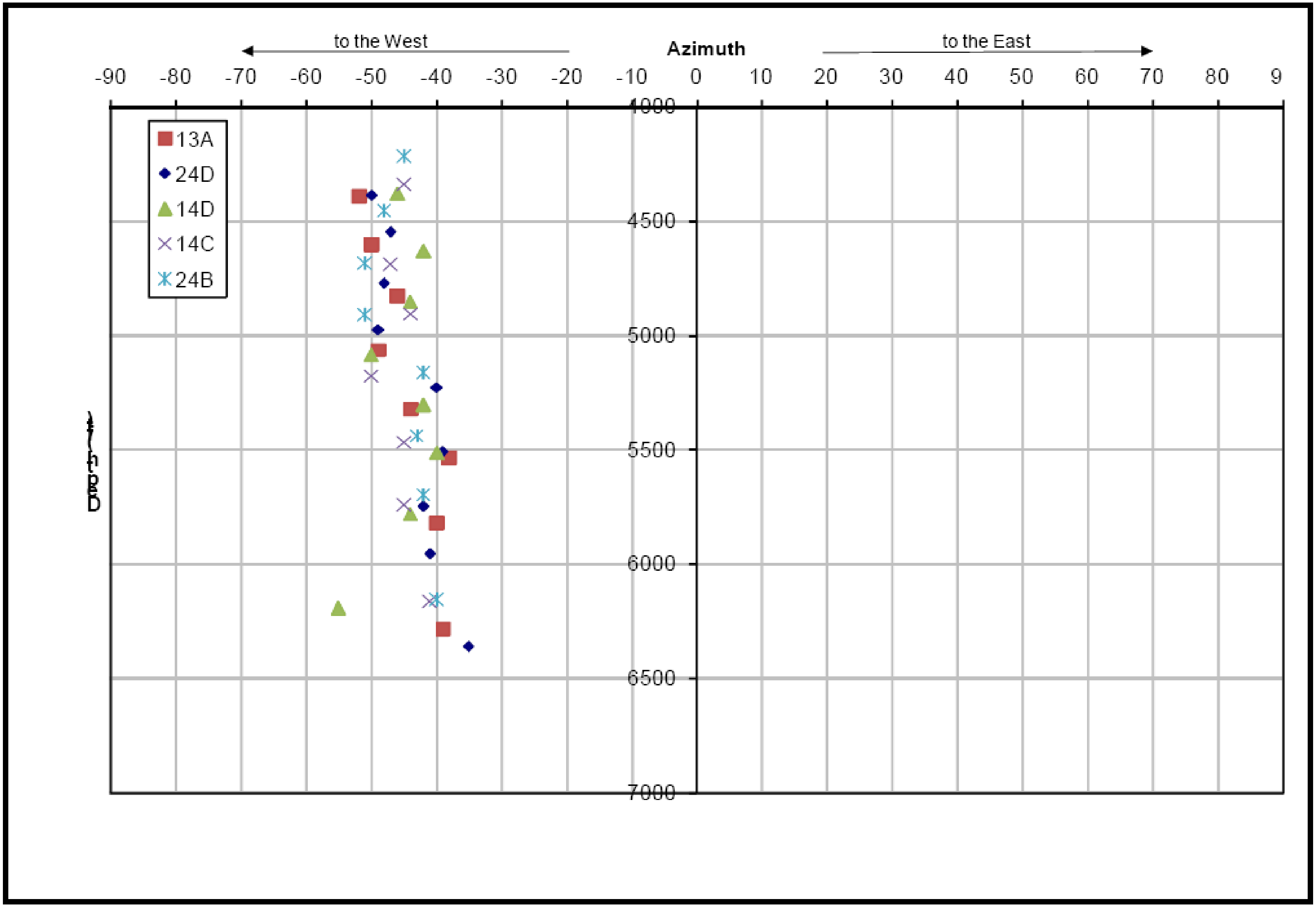

Figure 4. Fracture azimuth as a function of depth for all wells.

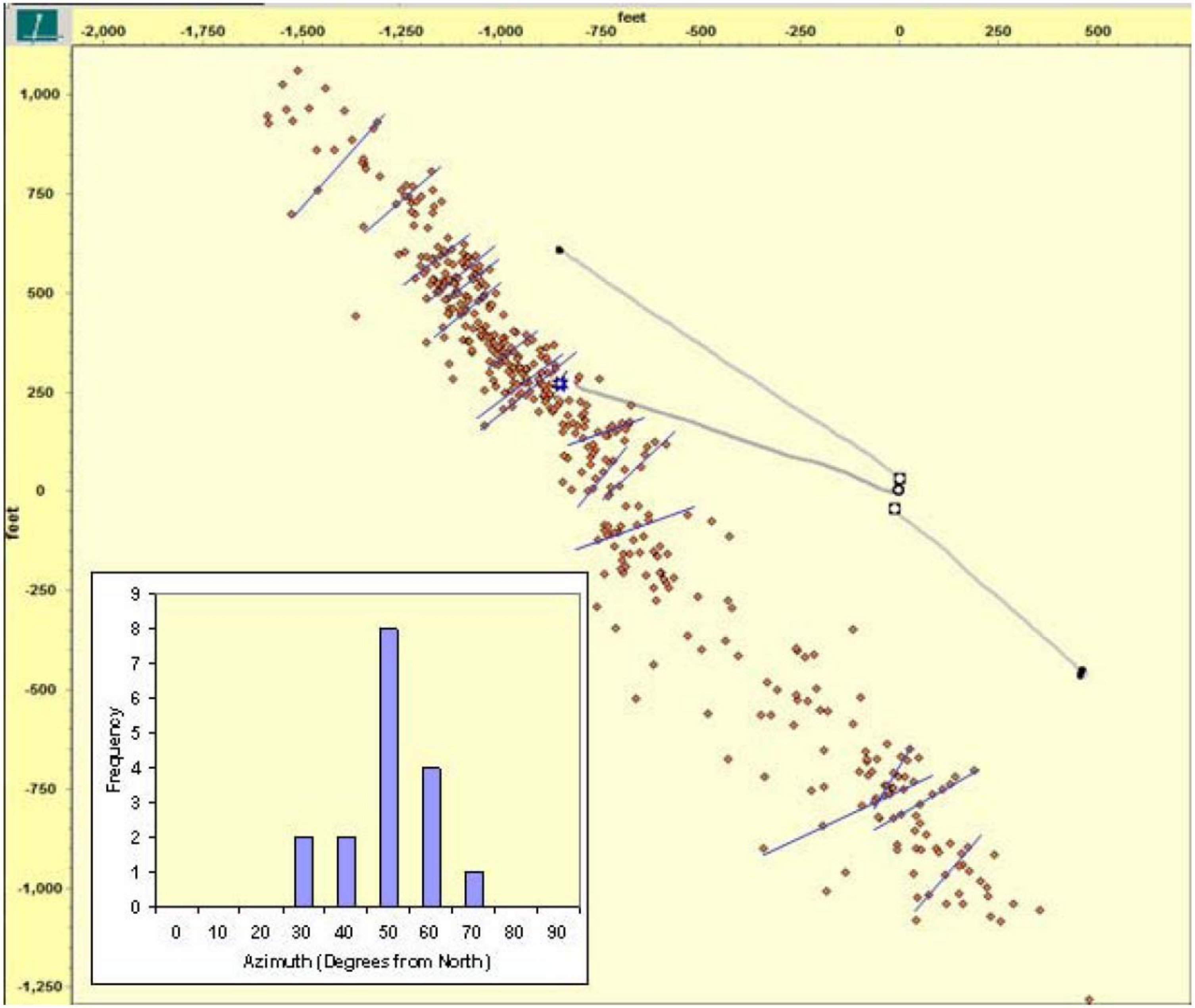

Figure 5. Fracture azimuth as a function of depth for all mapped fracture-treatment stages in all wells.

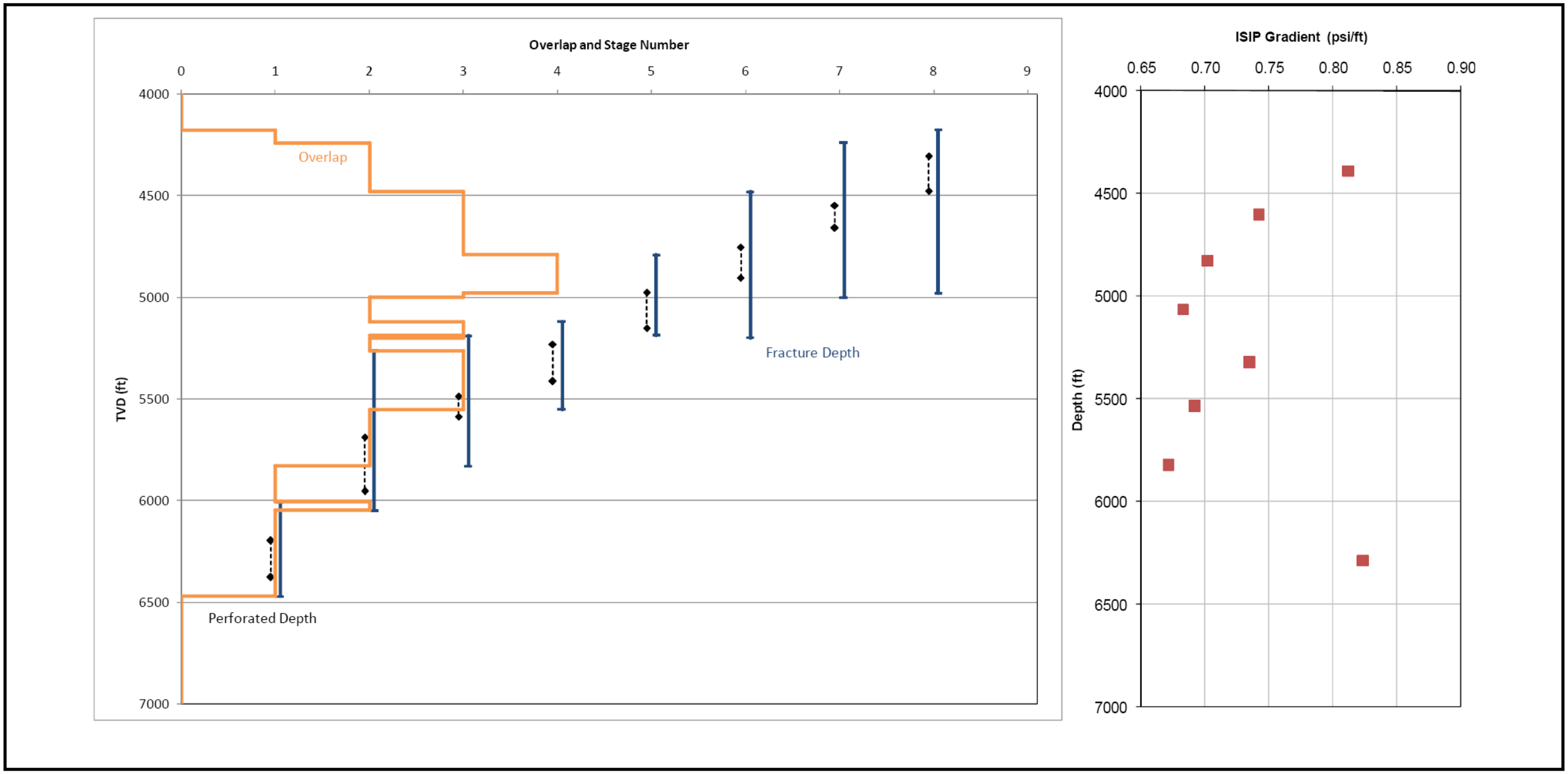

Figure 6. Height coverage and overlap for well 13A-36-692, all stages.

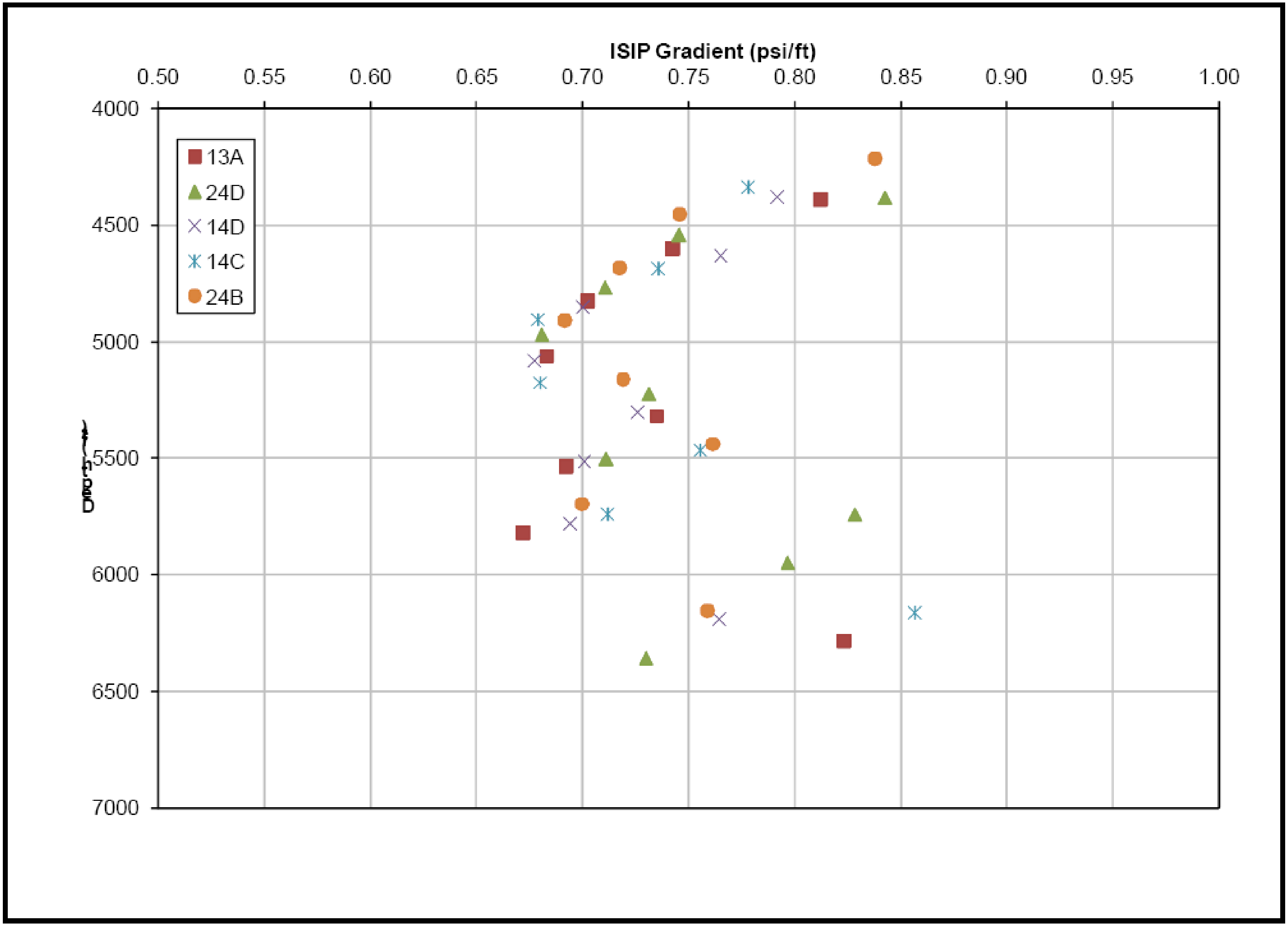

Figure 7. ISIP gradients vs. depth.

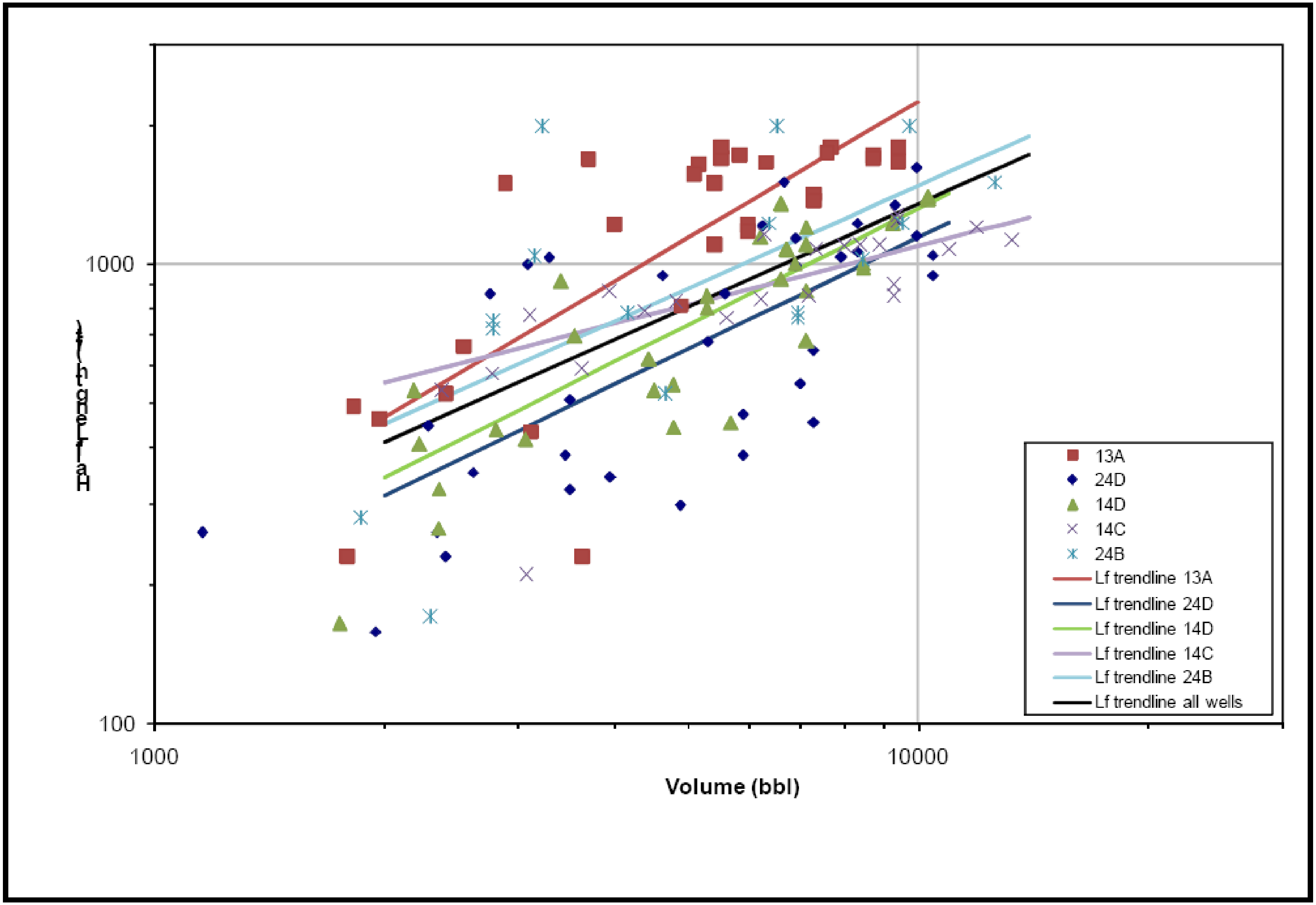

Figure 8. Half-length vs. injected volume.

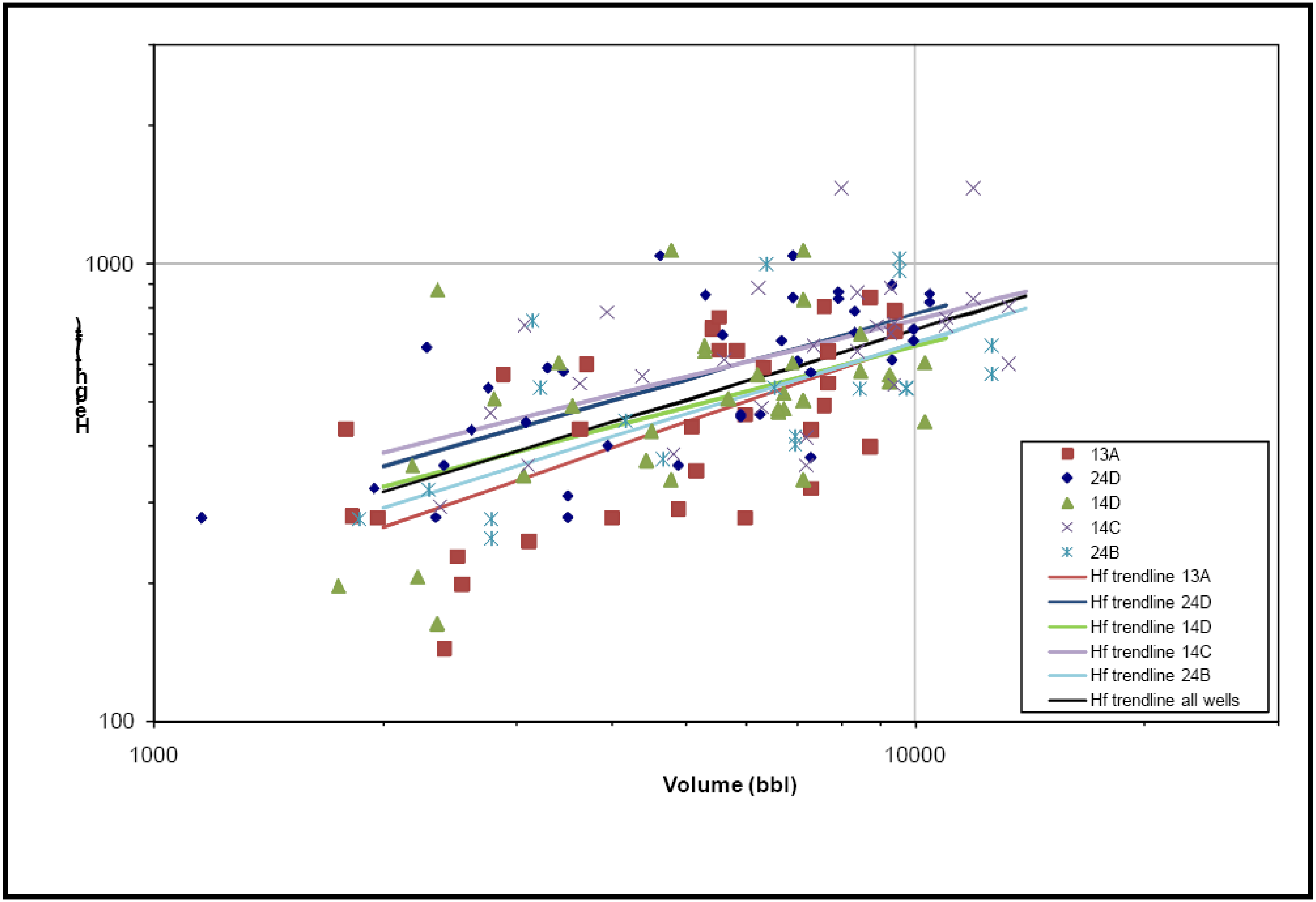

Figure 9. Height vs. injected volume.

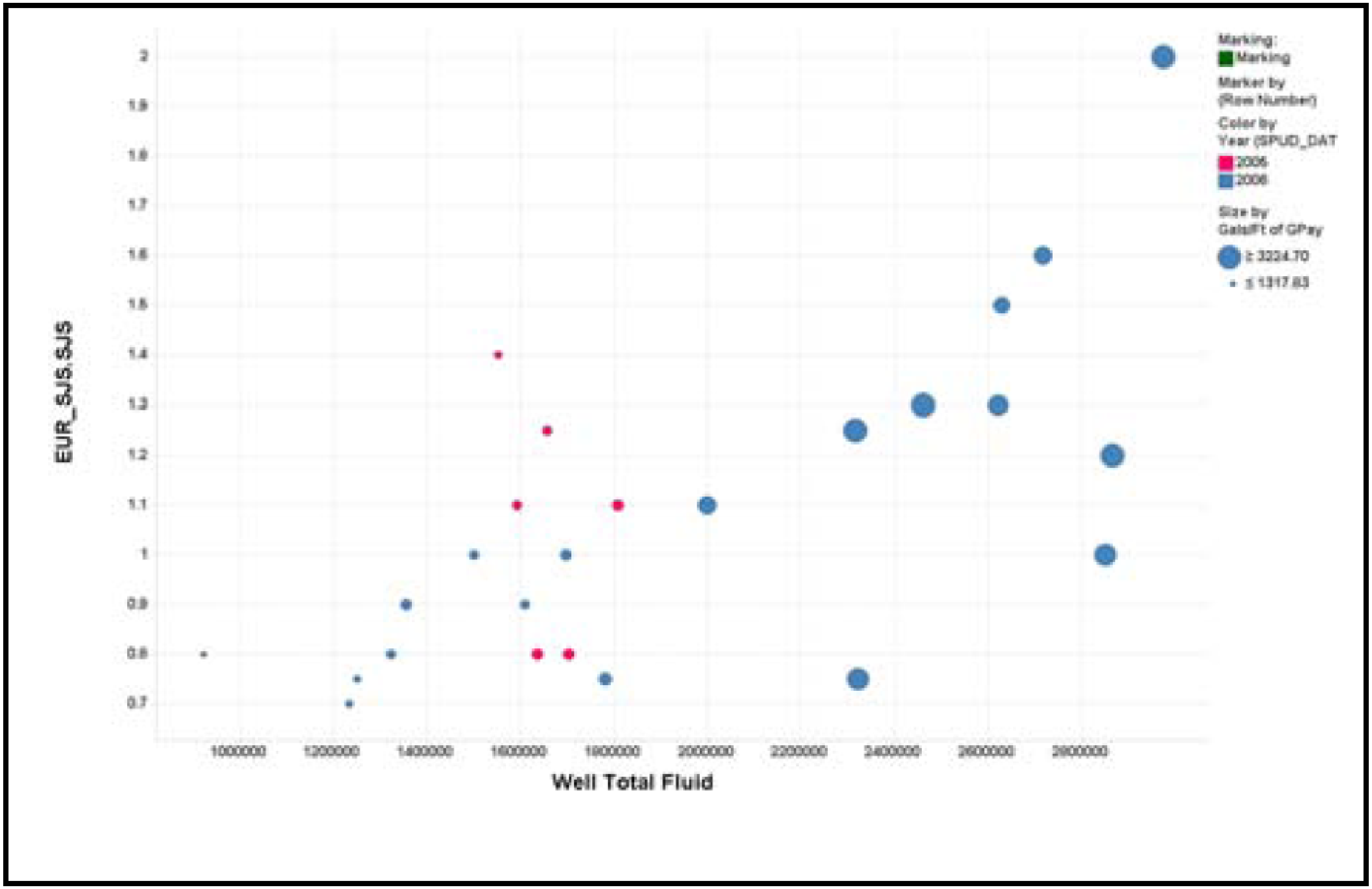

Figure 10. EUR vs. total injected fluid per well.

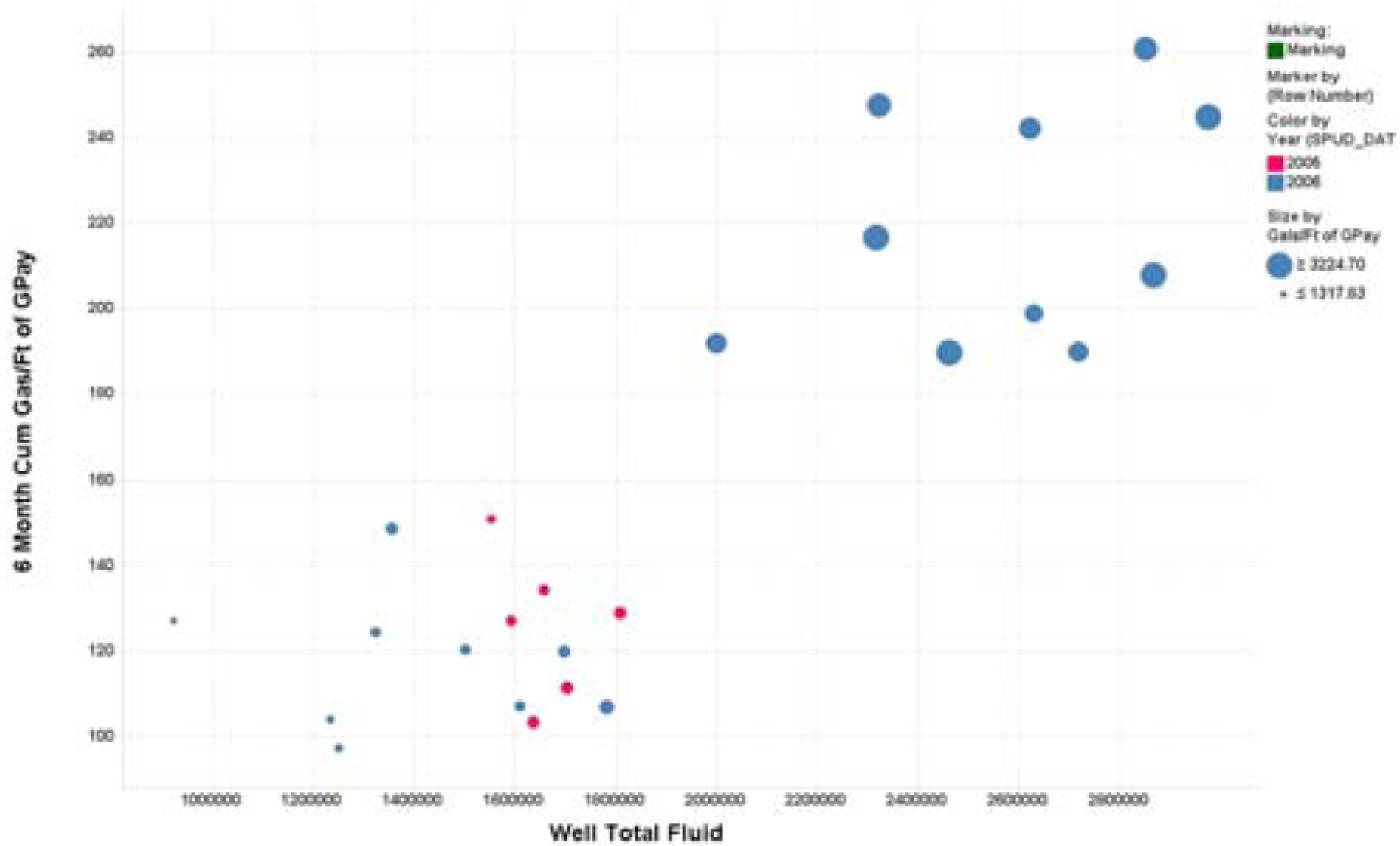

Figure 11. 6-Month cumulative gas per net foot of pay vs. total injected fluid per well (Salas et al., 2008).

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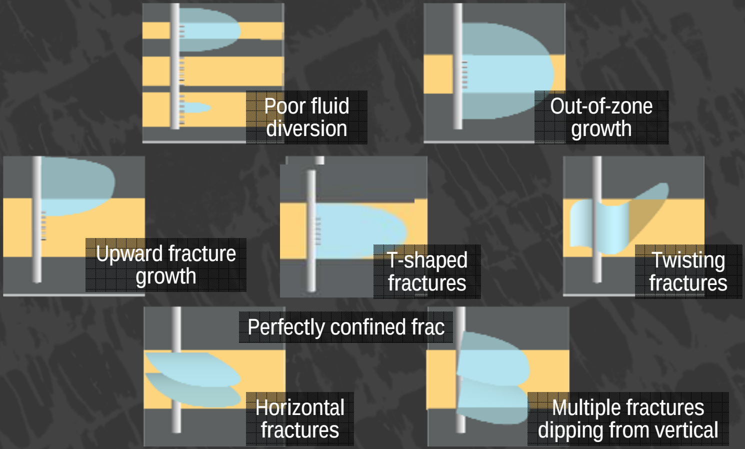
Bigger is Better – Hydraulic Fracturing in the Mesaverde Formation in the Piceance Basin

Leen Weijers, Yusuf Kama, Julie Shemeta and Steve Cumella
Pinnacle/Halliburton and MEQ Geo, Inc., Bill Barrett Corporation
AAPG Annual Convention & Exhibition
"Image the Past – Imagine the Future"
Denver, Colorado
June 9, 2009

We Know Everything About Our Fracs Except . . .

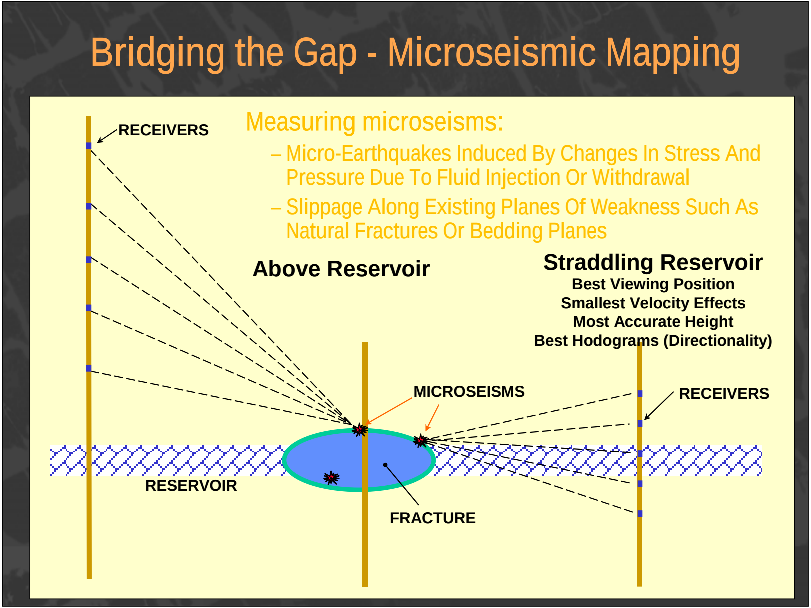


The Science – Engineering Gap

Various measurements are required to optimize production through hydraulic fracture stimulation

Let’s just frac that son-of-a-bitch*

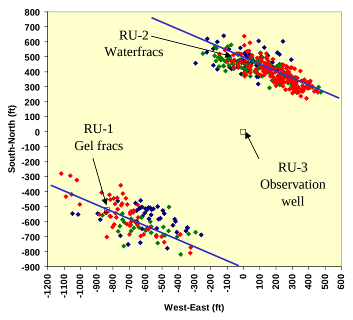
*Phrase originally coined by SPE President Steve Holditch

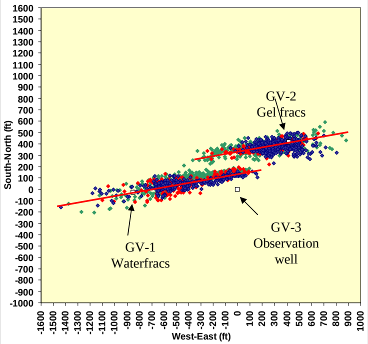


Bridging the Gap - Microseismic Mapping
Measuring microseisms:
– Micro-Earthquakes Induced By Changes In Stress And Pressure Due To Fluid Injection Or Withdrawal
– Slippage Along Existing Planes Of Weakness Such As Natural Fractures Or Bedding Planes
RECEIVERS
Above Reservoir
Straddling Reservoir
Best Viewing Position
Smallest Velocity Effects
Most Accurate Height
Best Hodograms (Directionality)
MICROSEISMS
RECEIVERS
RESERVOIR
FRACTURE

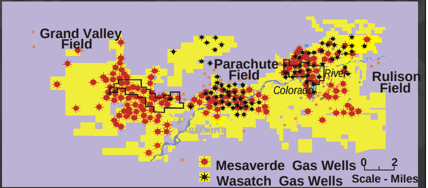
Rockies Fracture Stimulation Issues

- Fracture Azimuth & Length
  - Well placement for infill drilling



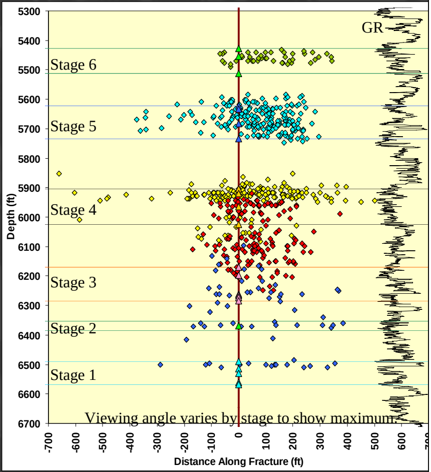


SPE 95637 (Williams Prod. Co)



Rockies Fracture Stimulation Issues

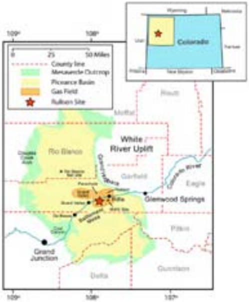
- Fracture Height Coverage of Large Pay Intervals
  - Is diversion appropriate in stage 1?
  - Why can't I break down stage 2?
  - Why does stage 3 grow upward?
  - Should I skip stage 4?
  - Can I combine stage 5 and 6?
  - Was sufficient length created in stage 6?



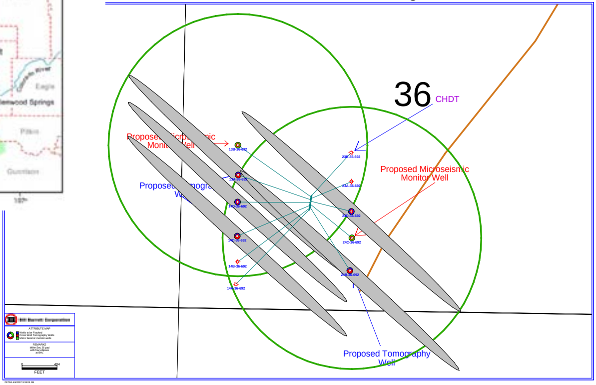
Engineering Uses of Mapping Data

- Determine Azimuth
  - Optimize well location to maximize recovery
  - Optimize horizontal well azimuth for best fracture geometry
- Determine Fracture Height
  - Optimize perforating strategy
  - Reduce out of zone growth, potentially increase half-length
- Determine Fracture Half-Length
  - Optimize well location to maximize recovery
  - Optimize frac stage volume
- Determine Fracture Coverage in Horizontal wells
  - Optimize Completion Design, Stage size, spacing etc.
  - Maximize Stimulated Reservoir Volume (SRV) and production

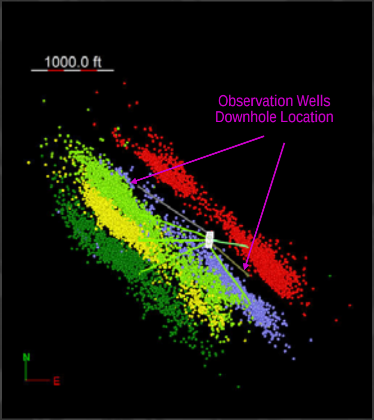
Piceance Basin - Mamm Creek Project Setup

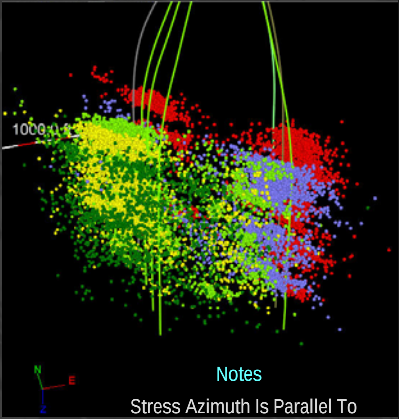


- Microseismic data from fracture treatment in five wells
  - Multiple stages (40 total)
  - Two monitoring wells



Microseismic Mapping Data





Notes

Stress Azimuth Is Parallel To Natural Fracture Azimuth

Linear Features Can Be Observed In The Data – Even At This Scale

Areal Coverage At This spacing

Note of Presenter: The data that we want to focus on is the microseismic data from a five-well monitoring project. The two plots show plan-view and side-view images of all of the microseismic data taken from up to seven stages in each of the five wells. There is an enormous amount of engineering information in here, but the focus of this presentation is on the information that can be gleaned about the reservoir and how it reacts to stimulation.

Need to note that some of the apparent curvature in plan view is due to rotating stress azimuth and some is due to changing velocity structure.

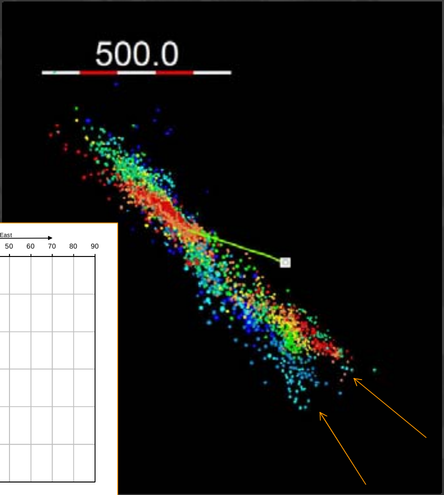
Typical Piceance Completion & Stimulation

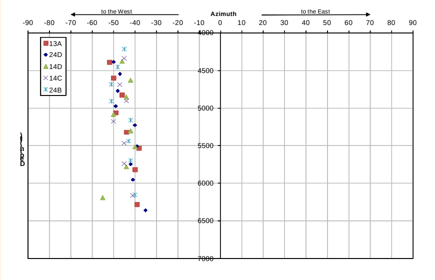
- Slickwater
  - 2,000 – 13,000 bbl/treatment
- Limited Entry
- Rate: 25-80 bpm
- Sand: 50 – 500 klbs
  - Ottawa 20/40 & 30/50
- 4 – 10 Stages
  - Up To 7 Perforation Clusters Per Stage
- Often Designing On A Set Volume Of Fluid Per Foot Of Zone & Weight Of Sand Per Foot Of Zone
  - 500 – 4,000 gal/ft net

- Variable Reservoirs Stimulated
  - Limited Cozzette/Corcoran
  - Widespread Cameo Production
  - Widespread Williams Fork Fluvial

Fracture Azimuth

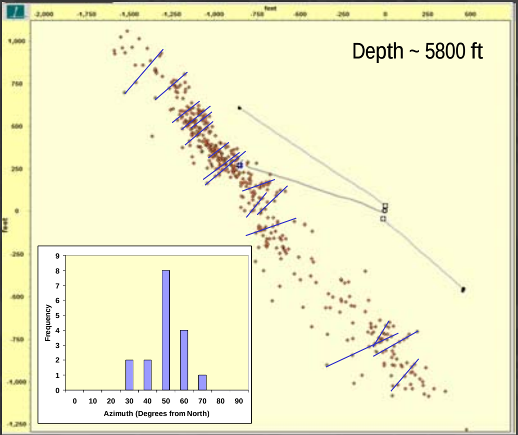
- Stress Rotation With Depth
  - 10° Rotation With Depth





Fracture Complexity Possible

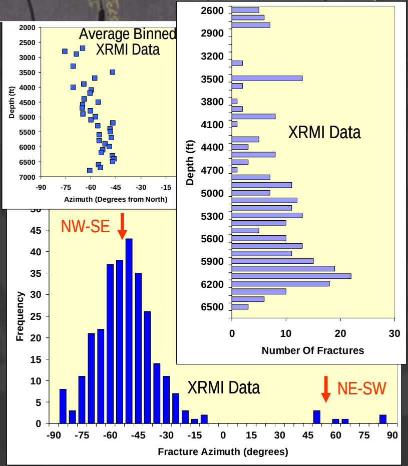
- Single Stage Of One Well's Stimulation
  - Long Fracture Length
  - Noticeable Linear Features
    - Aligned With Stress Azimuth & Primary Natural Fracture Azimuth
      - 2 Or 3 Subparallel Hydraulic Fractures
    - Aligned With Secondary Set Of Natural Fractures?
      - Roughly Orthogonal To Primary Natural Fracture Azimuth
    - Varying Width Of Microseismic Cloud
      - Related To Flow Into/Through Natural Fractures?



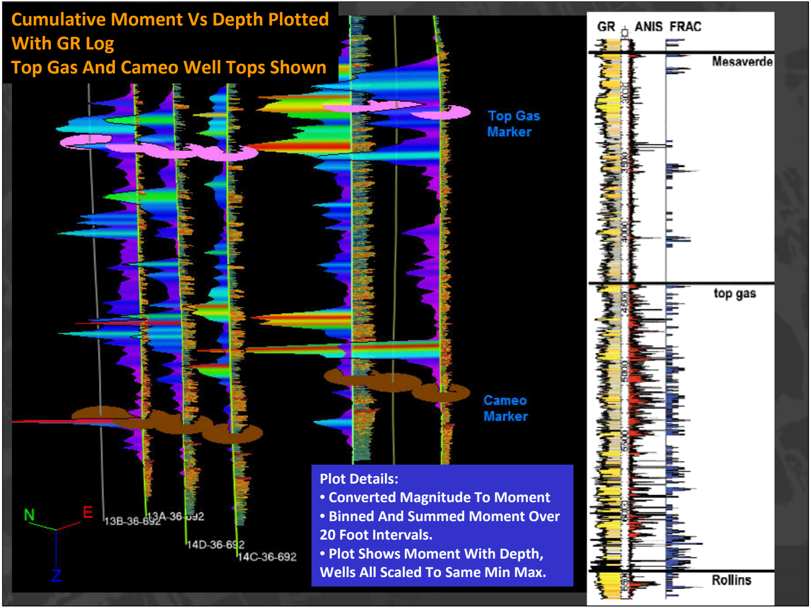
Note of Presenter: Most importantly, when we begin to look carefully at the microseismic data, we see the fracture running in the stress azimuth direction, which is parallel to the natural fractures, and even some indications of multiple parallel fractures. Could it be opening natural fractures as it propagates? There are also many linear features aligned northeast-southwest. These appear to be natural fractures undergoing shear in response to fluid movement orthogonal to the hydraulic fracture. Some of the planes are highlighted (ones that can be seen at the end of the treatment), but there are many more that can be identified by stepping through time. The inset shows the azimuths of the ones highlighted in the figure. There were only a few natural fractures observed in XRMI log that have this orientation, but these may be the most important fractures for effective drainage.

Natural Fractures From Image Logs & Core

- Natural Fractures Observed In Close Offset Well
  - Maximum Frequency At ~4800 – 6400 ft
  - Dominant Azimuth Of NW-SE
    - Wide Spread Of Azimuths
    - Primarily In -70° To -35° Range
  - Rotation With Depth
    - ~35° From 2,500 To 6,500 ft
  - Minor Secondary Fracture Set NE-SW
    - Important For Interconnection



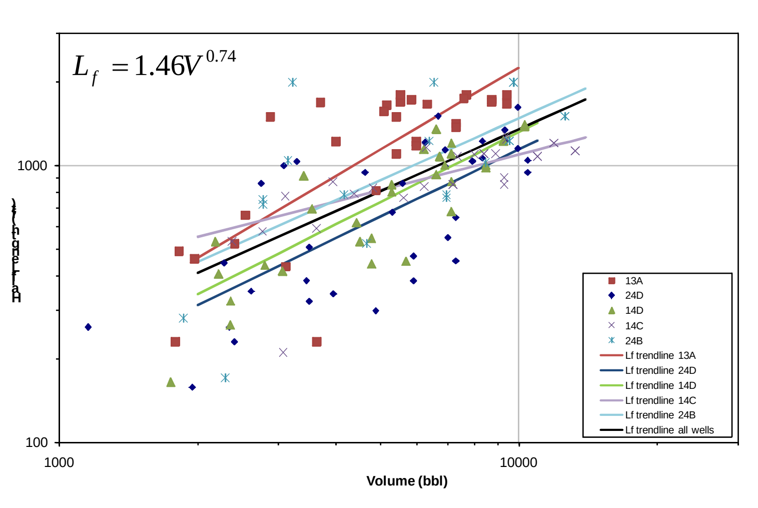
Note of Presenter: Natural fractures seen in core are open, partially cemented, and cemented. There is a wide range of fracture azimuths in the FMI data, but some of this is due to a rotation of the natural fractures with depth, as seen in the binned average azimuth. The dominant natural fracture azimuth is NW, which is parallel to the Grand Hogback



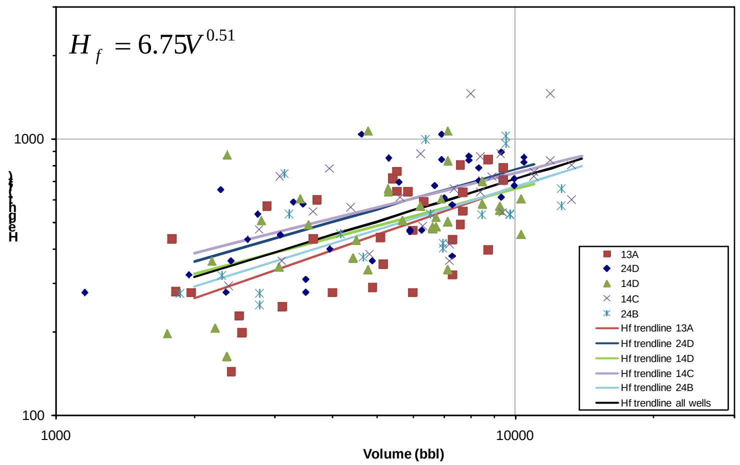
Note of Presenter: Summing the seismic moments for all of the data allows us to determine where the greatest shear behavior is occurring. Interestingly, more occurs at the top where there are fewer natural fractures.

One possible explanation could be that the natural fractures near the top of the section are rotated somewhat off of a principal stress plane, providing more shear stress and easier activation. Another explanation might be changing stress conditions, which can be observed in the treatment data.

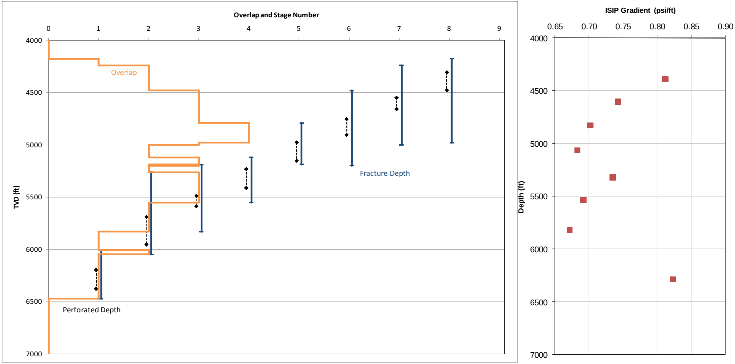
Correlation between Half-Length and Volume



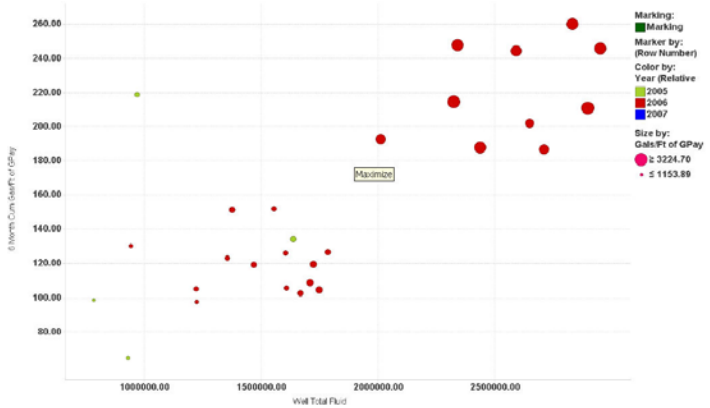
Correlation between Height and Volume



Height Overlap in Intervals with Low ISIPs



Correlation between Production and Volume



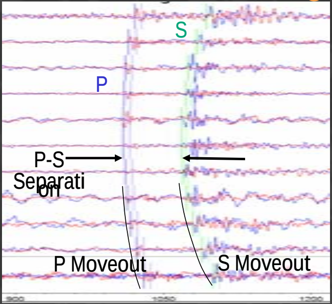
From: Salas et al., SDSM&T 2008

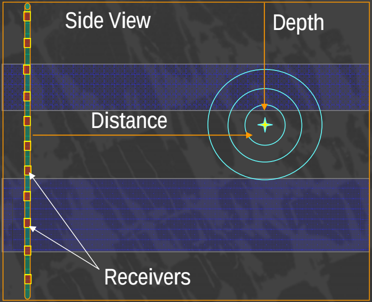
Conclusions

- Microseismic fracture mapping data can help determine critical engineering parameters such as fracture azimuth, complexity, height coverage, half-length and production response
- Larger fracture treatments in Mamm Creek lead to longer half-lengths, which in turn result in higher production and EURs
- Out-of-zone fracture height growth is observed in many stages, resulting in large areas of height overlap, especially at depths with low ISIPs

Thank you

Locating Microseisms





- Distance Obtained Primarily From P-S Separation
- Depth Obtained Primarily From Moveout
- Direction Obtained From Wave Particle Motion (Vibration)
  – P-Wave: Always Pointed In Direction Of Wave Propagation (Back To Source)
  – S-Wave: Orthogonal To P Wave