# Surface Tiltmeter Fracture Mapping Results for the Klatt No. 31-14H

## Final Report for Marathon Oil Company

**Project No.: MARA-1677**

**Report Date: November 14, 2007**

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# 1. Summary

Pinnacle Technologies, Inc. provided surface tiltmeter (STM) hydraulic fracture mapping services to Marathon Oil Company for the horizontal well Klatt No. 31-14H Bakken wildcat. The project was located in Dunn County, North Dakota. The objectives of the STM mapping service were to:

- Measure the dominant fracture azimuth in the Klatt No. 31-14H with respect to the existing wellbore lateral, such that decisions may be made regarding optimum placement of new-drills involved in future development
- Evaluate the relative degree of even (or uneven) volume distribution of injected fluid along the lateral wellbore

The STM array, consisting of 80 locations, was constructed and positioned above the Klatt No. 31-14H lateral extent. Surface tiltmeters were installed in 30-ft cased and cemented boreholes for mechanical and thermal stability. The area of interest and each tiltmeter location are shown in **Figure 1, Figure 2**, and **Figure 3**. The specific locations of each tilt site surrounding the drill well are presented in tabular format in **Table 2.**

The Klatt No. 31-14H has an approximately 7,000-ft lateral section at about 10,886 ft TVD, with 4½-inch, 11.6 lb/ft, L80 perforated pipe lying uncemented in the original openhole. Perforations were spread relatively evenly across the horizontal portion in an effort to promote even fluid distribution. The well was fracture-stimulated twice, and tilt response was analyzed both times. Originally a single massive stage was planned, but a wellhead isolation tool failure and casing failure mid-treatment caused premature termination of pumping operations on 7/23/2007. A second stimulation treatment was performed several weeks later on 9/5/2007 after the casing was repaired. For purposes of clarity, the two stimulation efforts have been labeled “Stage 1” and “Stage 2,” even though the second stimulation operation was really intended to replace the first one that was prematurely terminated.

The first treatment consisted of about 4,000 bbl that placed 296,000 lb of 40/70 Ottawa Sand in a high viscosity crosslinked fluid (SilverStim™, intended for moderate to high permeability). The second treatment utilized 6,500 bbl of slickwater to place 193,000 lb of proppant after it became apparent that a lower permeability, naturally fractured scenario in the Lower Bakken might be present. Pumping rates averaged about 60 bpm with surface pressures averaging 7,000 psi. The maximum proppant concentration was 1 ppg.

Fracture mapping results are summarized in **Table 1**. The first stage had a couple of notable changes during pumping, so we have divided it into two parts: the first 40 minutes, and then the treatment as a whole. The wellbore was divided into three sections; heel, middle, and toe.

Volumetric distribution of fluid along the lateral during the first stimulation attempt was uneven. During the first 40 minutes of pumping, most of the fluid exited the lateral close to the toe and middle of the lateral, creating transverse fracture(s) near the toe (of azimuth approximately N87°W), and longitudinal fracturing (of azimuth ~N-S) in the middle portion. As the fracturing operation progressed, some limited transverse activity (of azimuth ~E-W) was noted in the middle portion, with more fluid exiting the toe. Only 30 to 35% of all the fluid in both stages was used to create longitudinal fractures, while 10 to 20% was used to create horizontally oriented fractures. The majority of the fluid in both stages, about 45%, was used to create transverse

fractures, while fractures at an oblique orientation (approximately N45°W) in stage 2 accounted for 15% of the treatment volume.

Volumetric distribution of fluid along the lateral during the second stimulation attempt was also uneven, but a higher percentage exited near the heel than during the stage 1 attempt. **Figure 4** is a side-by-side comparison of the two treatments, where the various induced fracture directions are indicated by the colored shapes: circles represent a horizontal component, and the high-aspect ratio ovals represent vertical fracturing. It is important to note that the lengths [or diameters] of these shapes are not representative of fracture length or half-length. The second stage may have effectively stimulated a portion of the wellbore that was not stimulated the first time around (the heel). The middle portion of the lateral may have been somewhat under-stimulated during both attempts.

## Table 1. Job Summary

| | | | |
|---|---|---|---|
| **Company:** | Marathon Oil Company | **Project No.:** | MARA-1677 |
| **Treatment Well:** | Klatt No. 31-14H | | |
| **Surface Location:** | N47.47164 W102.74444 | **API No.:** | 33-025-005990000 |
| **Field:** | Wildcat | | |
| **County:** | Dunn | **State/Province:** | North Dakota |

| | | | |
|---|---|---|---|
| **Services Provided:** | ☐ Fracture Microseismic | ☐ Downhole Tilt Mapping (☐ TWT / ☐ OWT) | ☒ Surface Tilt Mapping |
| | ☐ Reservoir Monitoring | ☐ Consulting Services (☐ Engr. / ☐ Supv. & QC) | |

| | **Units** | **First 40 min of Stage 1** | **Stage 1** | **Stage 2** |
|---|---|---|---|---|
| **Treatment Date:** | | 7-23-07 | 7-23-07 | 9-5-07 |
| **Observation Time:** | | 08:01 – 08:41 | 08:01 – 09:24 | 15:24 – 17:43 |
| **Formation:** | | Bakken | Bakken | Bakken |
| **Perforated Interval (MD):** | ft | 10,906 – 16,696 | 10,906 – 16,696 | 10,906 – 16,696 |
| **Datum:** | ft | WGS-84 | WGS-84 | WGS-84 |
| Nature of dominant fractures at **heel** of lateral: | | Unknown | Horizontal | Transverse (~N81°W) |
| Nature of dominant fractures in **middle** of lateral: | | Longitudinal (~N-S) | 15% Tranverse (~N87°W), 15% Longitudinal (~N-S), 10% Horz | Longitudinal (~N8°E) |
| Nature of dominant fractures at **toe** of lateral: | bbl | Transverse (N87°W) | 30% Tranverse (~N87°W), 20% Longitudinal (~N-S) | 15% Oblique (~N45°W), 10% Horz |
| Overall volume fraction of fluid exiting at **heel** of lateral: | % | 20 | 10 | 45 |
| Overall volume fraction of fluid exiting in **middle** of lateral: | % | 40 | 40 | 30 |
| Overall volume fraction of fluid exiting at **toe** of lateral: | % | 40 | 50 | 25 |
| Volumetric uncertainty in **heel** of lateral calculations: | % | N/A | 12 | 7 |
| Volumetric uncertainty in **middle** of lateral calculations: | % | N/A | 14 | 11 |
| Volumetric uncertainty in **toe** of lateral calculations: | % | N/A | 2 | 11 |
| Absolute volume pumped: | bbl | 3,892 | 3,892 | 6,553 |
| Pump rate: | bpm | 47 | 48 | 61 |
| **Pinnacle Technologies Personnel:** | | | | |
| Array Installation | | S. Logan | | |
| Tiltmeter Analyst | | D. Astakhov | | |
| Project Manager | | D. Walser | | |
| Documentation | | D. Walser | | |
| Report Review | | L. Weijers | | |

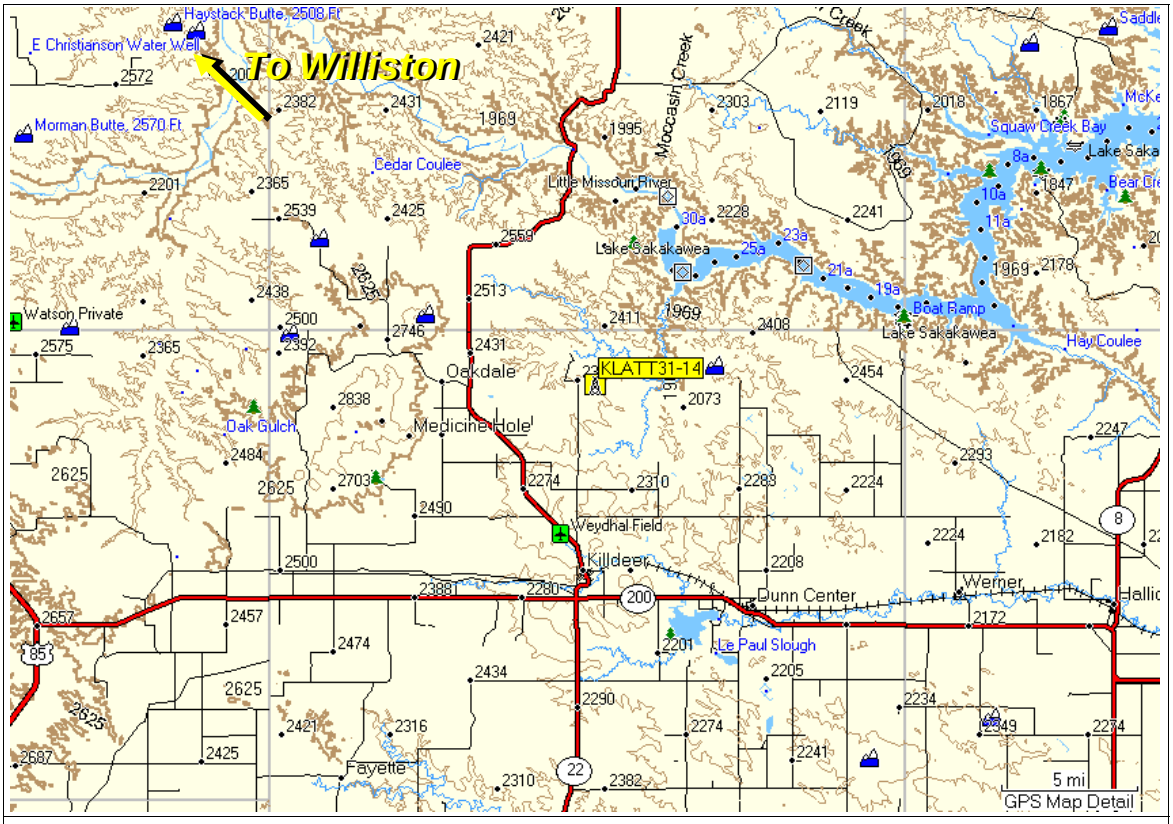



**Figure 1. General area near the Klatt No. 31-14H**

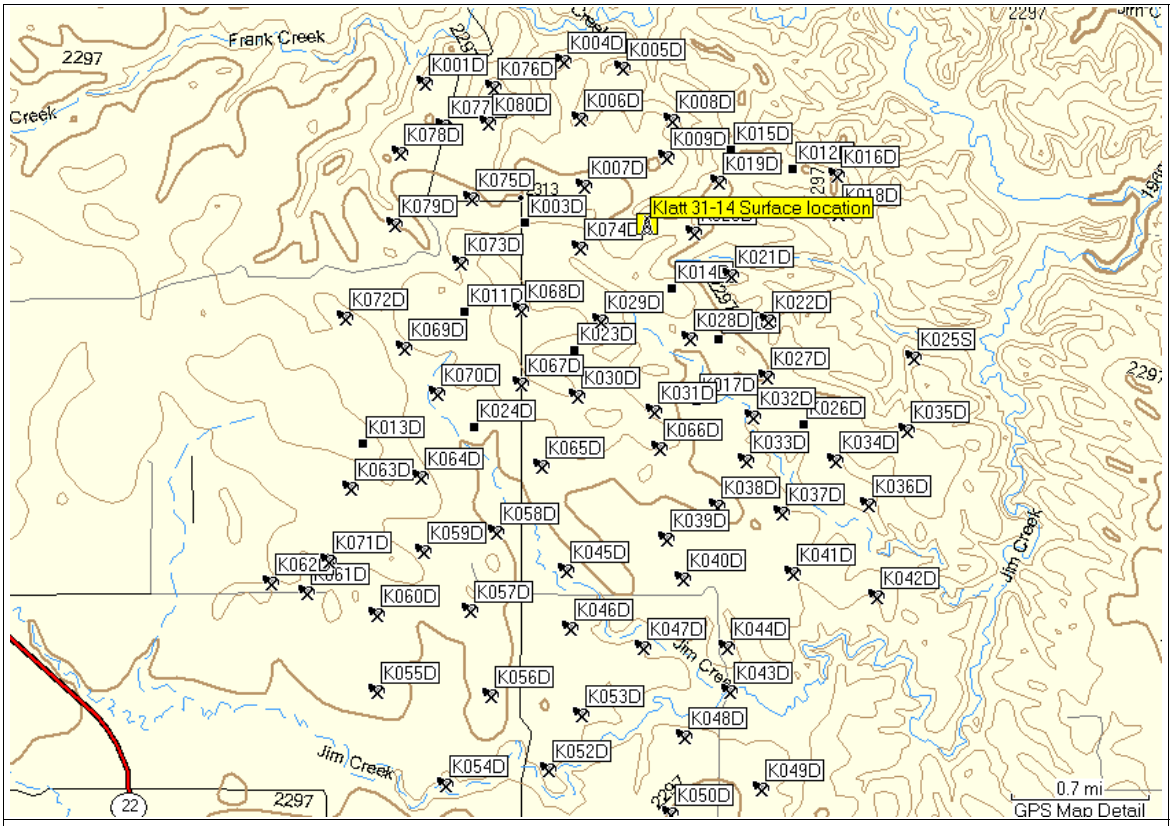



**Figure 2. Surface tiltmeter locations**

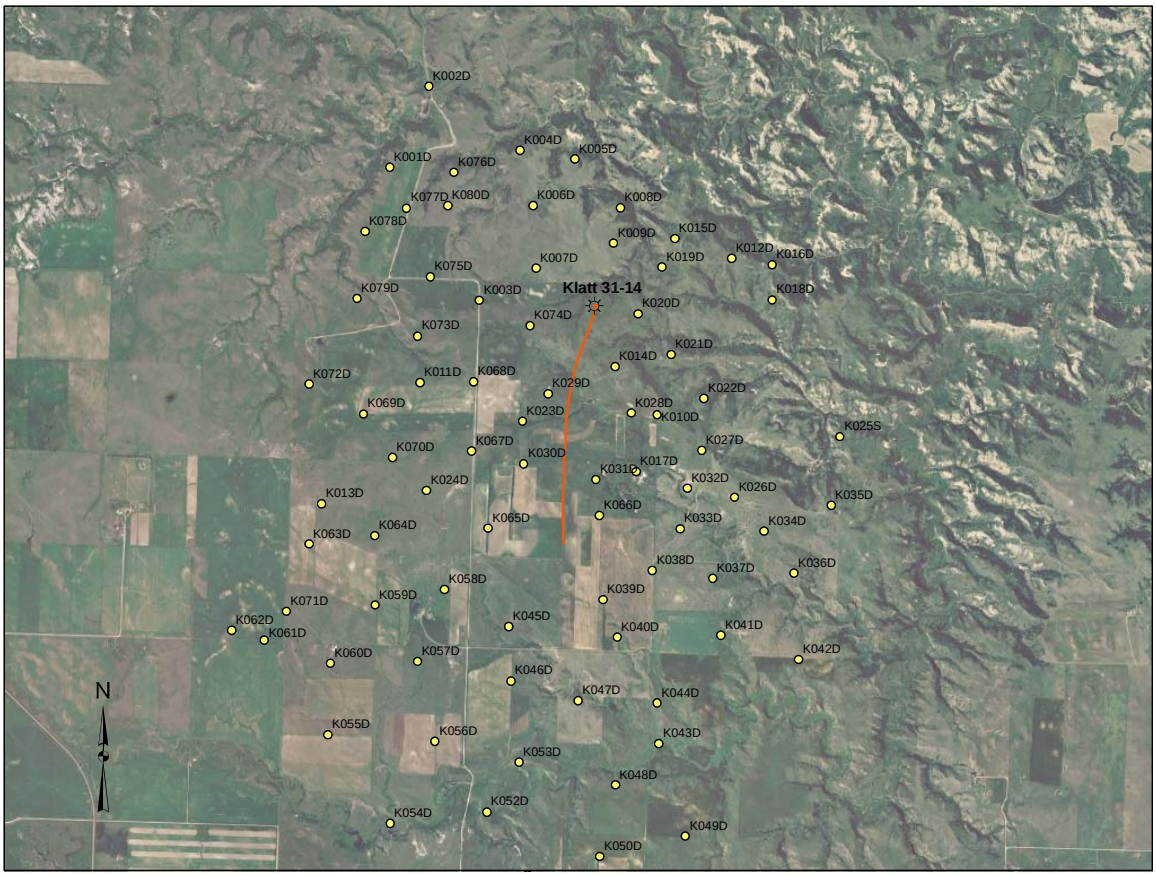



**Figure 3. Surface tiltmeter locations overlaid on area photo**

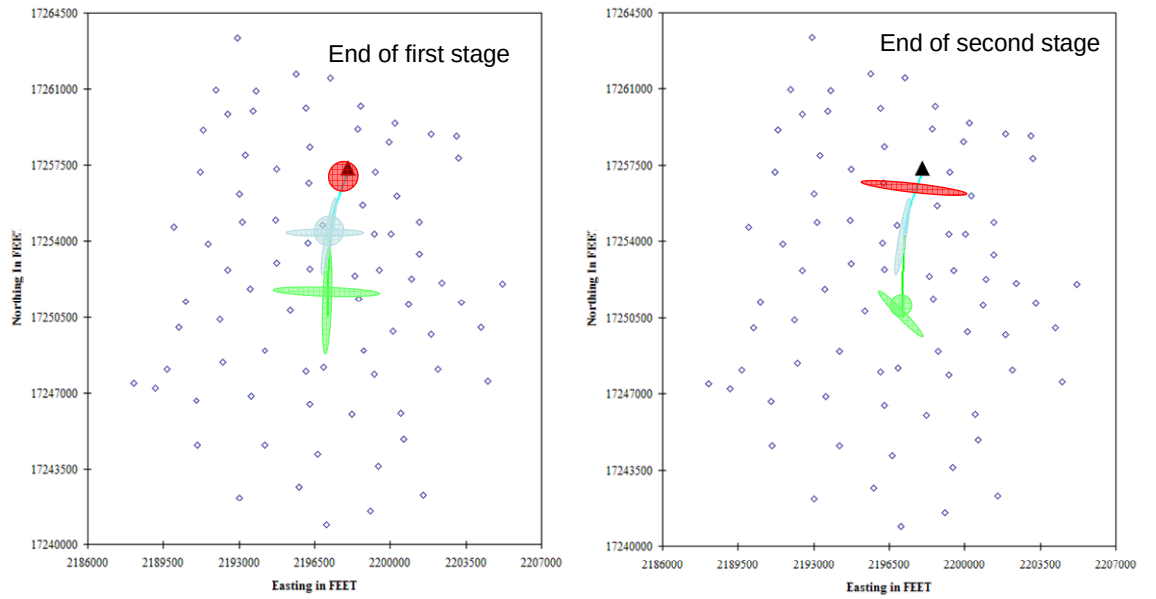



**Figure 4. Comparison of results for both stages**

# 2. Recommendations

The following recommendations are presented for consideration and discussion:

1. **Utilize the results of the tilt measurements for future lateral positioning decisions.** Offset development of low permeability reservoirs should keep the approximate N-S lateral orientations to take advantage of the potential of transverse fracturing. There exists a permeability cut-off value above which effective permeability to oil at the appropriate confining stress would dictate that promoting longitudinal fractures (via an E-W lateral) would be more appropriate. Though the exact value of that cut-off is unknown, there are other basins and lithologies that suggest that oil reserves with k greater than 0.1 to 0.4 md by historical production transient analysis (or 10 to 30 md by core to air) fall into this category. It follows that there exists a similar permeability cut-off for gas reservoirs, and again, the value for k (or kh) is unknown, but out-of-area studies with k > 0.05 md would generally be considered permeable enough to warrant longitudinal fracturing, therefore laterals should be placed along the maximum principle stress. The ±N87°W induced fracture azimuth is also useful in that stimulated completion overlap may be avoided in tight spacing scenarios where fluid exit out of casing is controlled.

2. **Maximize exposed reservoir surface area and, consequently, maximize Stimulated Reservoir Volume (SRV).** There is some evidence that in ultra-low permeability reservoirs, the rock volume that produces the EUR is only slightly larger than the volume that is stimulated. It is not known exactly how SRV may be impacted by process, but it is thought that high pump rate, low viscosity fluids, and high fluid volumes are often major contributing factors.

3. **Encourage fracture development far from the wellbore.** Often, Bakken completion laterals targeting the two shale members with acceptable vitrinite reflectance ($R_o$) and Total Organic Carbons (TOC) are placed along a relatively thin silty arenaceous limestone or dolomite section between the two, in order to promote wellbore stability and prevent a host of drilling problems. There are large areas in the basin where prominent vertical natural fracturing is sufficiently limited that stimulation efforts must penetrate excessively long distances from the wellbore in order to promote commercial production rates. One method to accomplish this is with large volumes of low-viscosity fluids.

4. **Re-examination of the decision to stimulate via uncemented laterals might be warranted.** It is possible that total SRV is being sacrificed for "ease of completion." Though other wells in this play have encountered extreme difficulty in terms of operationally placing fluid and proppant into perforations in cemented laterals, we would suggest that methods to overcome most or all of these difficulties have been developed and refined to the point that they are worth study and consideration. Cementing a lateral could promote:

    a. Relatively even placement of fluids along the lateral extent

    b. Increased SRV (if fluids and proppant are successfully placed)

5. **Consider microseismic monitoring of future wells in the play**. Microseismic monitoring delivers fracture height, length, azimuth, and an indication of the relative degree of complexity of the induced fracture network. It may be that knowledge of fracture height and length could impact decisions with respect to pump rate, lateral placement, and cluster placement along the lateral. For cases where there are no suitable observation wells present, Treatment Well Microseismic Monitoring (TWMM) is a technology that can be useful, in that it is applicable in both vertical and horizontal wellbore geometries. The cost of horizontal TWMM is about the same as the cost of an 80-site STM array.

6. **Consider third-party consulting for situations where "difficult" cemented laterals need to be stimulated.** Pinnacle Technologies has extensive domestic experience in working with engineering and operations associated with hard-rock completions in "difficult" situations, and is available for contract.

# 3. Discussion

## 3.1 Background

The target formation is the Mississippian/Devonian Bakken, and consists of three overlapping members: a lower organic-rich black shale, a middle porous, silty arenaceous limestone or dolostone section, and an upper organic-rich black shale. The Bakken Formation overlies the Upper Devonian Three Forks Formation, and underlies the Lower Mississippian Lodgepole Formation.

Dolostones and siltstones in the middle member typically consist of fine grained to very fine grained, matrix-rich rocks that exhibit permeabilities commensurate with grain size and sorting regimes. Most grains are well rounded to rounded, but in lower permeability reservoirs, the finer grained material is subrounded or subangular. Common lithic fragments in the siltstones include detrital carbonate (limestone and dolomite) grains and deformed mudstone clasts. The matrix in the sandier portions of the Middle Bakken also contains a variable mix of carbonate mud and allo-genic clay.

Multiple fracture types occur on a macroscopic and microscopic scale, and are most abundant in the lower and middle members. In siltstones, sandstones, and dolostones of the middle member, the vast majority of these fractures (when they occur) are open and nonmineralized, discontinuous features oriented subparallel (horizontal) to bedding. Resinous or vitreous pods of carbonaceous material ("dead oil") are present locally along some horizontal fractures. Fractures in the lower member typically are open bedding plane type, or open hair-like vertical features.

It is thought that hydraulically stimulating the middle Bakken member results in the opening of microfractures or naturally occurring planes of weakness in the two shale members above and below, and that if the induced fractures are propped, then these two organically rich members may contribute substantially to production, especially when the TOC numbers are high and the shale is reasonably thermally mature ($R_o$ moderate or high). In most portions of the basin, the middle Bakken itself may not hold reserves substantial enough to warrant commercial extraction; it follows that efforts to adequately stimulate the shales are likely important in maximizing EUR's.

For the case of the Klatt No. 31-14H, it was deemed important to know whether or not transverse fracturing was possible with a generally N-S lateral, since it was suspected in advance that the middle Bakken member would not have sufficient permeability, porosity, or total reserves to be commercial on its own. The degree of natural fracturing was unknown, but it was suspected that it might be low, and planning efforts proceeded under the assumption that induced fracturing would be necessary to make the project fiscally viable.

## 3.2 Fracture Mapping Results

The surface tiltmeter array, consisting of 80 locations, was constructed in May of 2007 and centered about the Klatt No. 31-14H in a "rounded rectangle" shape that generally followed the planned lateral path. Most sites were located in a "racetrack" configuration around the lateral of interest, with the internal radius approximately 10% of the drill depth, and the outer radius approximately 75% of the drill depth TVD. **Figure 2** and **Figure 3** are map views of this, and it is apparent that high relief and extreme topography prevented a few sites from being constructed on the NW of the array. Surface tiltmeters were installed in 30-ft PVC 4-inch nominal diameter

cased and cemented boreholes for mechanical and thermal stability, and allowed to settle for several weeks to stabilize and record localized earth tide movement. The specific locations of each tilt site surrounding the drill well are presented in **Table 2**. Staking and drilling of the sites was performed in a manner that was minimally invasive, and wherever possible, existing roads, rights-of-way, and ATV paths were utilized for access to the tilt sites.

Two days prior to each fracture stimulation, measurements from the tilt sites were analyzed for earth tide patterns, and recommended windows of time for fracture-stimulation were presented to Marathon Oil Company. Earth tides are elastic deformations of the earth's crust due to rotation in the gravitational fields of the sun and moon. Although the actual movement associated with the tides is small, when a change of direction occurs, the tilt is quite easily measured with tiltmeters. Though the curves associated with this process are generally sinusoidal in nature, the actual change in tilt is relatively linear over short periods of time, as long as a "rollover" does not happen during that same period of time. **Figure 5** is an example of tilt associated with earth tides off STM site SU002, measured prior to the attempted fracture stimulation on the Klatt No. 31-14H that was used to forecast the optimum start times.

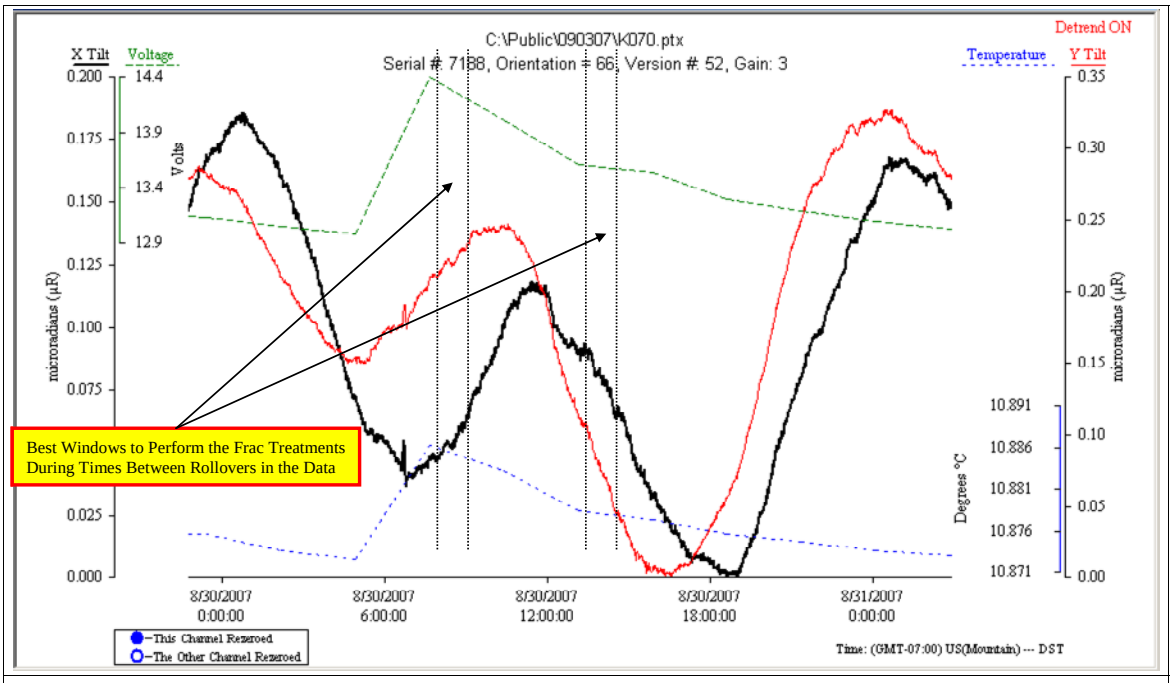



**Figure 5. Earth tides from site K070 and proposed stimulation windows prior to stimulation**

## Table 2. Actual Surface Locations of Each Site

| Site Name | WGS-84 Location | Elevation | Site Name | WGS-84 Location | Elevation |
|---|---|---|---|---|---|
| K001D | N47.48207 W102.76872 | 2298 ft | K042D | N47.44422 W102.71953 | 2262 ft |
| K002D | N47.48853 W102.76445 | 2131 ft | K043D | N47.43728 W102.73552 | 2209 ft |
| K003D | N47.47179 W102.75784 | 2380 ft | K044D | N47.44048 W102.73582 | 2281 ft |
| K004D | N47.48372 W102.75363 | 2253 ft | K045D | N47.44618 W102.75337 | 2326 ft |
| K005D | N47.48314 W102.74720 | 2211 ft | K046D | N47.44188 W102.75291 | 2289 ft |
| K006D | N47.47939 W102.75192 | 2275 ft | K047D | N47.44049 W102.74501 | 2281 ft |
| K007D | N47.47445 W102.75138 | | K048D | N47.43391 W102.74043 | 2296 ft |
| K008D | N47.47938 W102.74176 | 2268 ft | K049D | N47.43004 W102.73210 | 2291 ft |
| K009D | N47.47660 W102.74242 | | K050D | N47.42824 W102.74200 | 2296 ft |
| K010D | N47.46318 W102.73681 | 2357 ft | K051D | N47.42664 W102.75036 | 2304 ft |
| K011D | N47.46517 W102.76448 | 2420 ft | K052D | N47.43151 W102.75529 | 2277 ft |
| K012D | N47.47567 W102.72866 | 2264 ft | K053D | N47.43551 W102.75168 | |
| K013D | N47.45542 W102.77552 | 2464 ft | K054D | N47.43038 W102.76647 | 2244 ft |
| K014D | N47.46688 W102.74187 | 2404 ft | K055D | N47.43723 W102.77400 | 2339 ft |
| K015D | N47.47710 W102.73534 | 2292 ft | K056D | N47.43696 W102.76153 | 2329 ft |
| K016D | N47.47526 W102.72392 | 2306 ft | K057D | N47.44319 W102.76384 | |
| K017D | N47.45864 W102.73906 | 2284 ft | K058D | N47.44894 W102.76095 | 2296 ft |
| K018D | N47.47248 W102.72377 | 2202 ft | K059D | N47.44754 W102.76896 | 2341 ft |
| K019D | N47.47482 W102.73669 | 2310 ft | K060D | N47.44287 W102.77395 | 2319 ft |
| K020D | N47.47108 W102.73936 | 2344 ft | K061D | N47.44455 W102.78171 | 2352 ft |
| K021D | N47.46795 W102.73539 | 2289 ft | K062D | N47.44525 W102.78556 | 2367 ft |
| K022D | N47.46458 W102.73141 | 2269 ft | K063D | N47.45220 W102.77686 | 2386 ft |
| K023D | N47.46236 W102.75242 | 2388 ft | K064D | N47.45302 W102.76922 | |
| K024D | N47.45670 W102.76337 | | K065D | N47.45386 W102.75607 | 2331 ft |
| K025S | N47.46185 W102.71545 | 2125 ft | K066D | N47.45511 W102.74318 | |
| K026D | N47.45685 W102.72753 | | K067D | N47.45990 W102.75826 | 2439 ft |
| K027D | N47.46047 W102.73147 | 2296 ft | K068D | N47.46535 W102.75824 | 2462 ft |
| K028D | N47.46326 W102.73982 | | K069D | N47.46257 W102.77095 | |
| K029D | N47.46457 W102.74954 | 2442 ft | K070D | N47.45922 W102.76743 | |
| K030D | N47.45902 W102.75214 | 2455 ft | K071D | N47.44685 W102.77926 | |
| K031D | N47.45793 W102.74371 | 2343 ft | K072D | N47.46480 W102.77739 | 2399 ft |
| K032D | N47.45745 W102.73306 | 2274 ft | K073D | N47.46883 W102.76492 | 2389 ft |
| K033D | N47.45424 W102.73375 | | K074D | N47.46991 W102.75188 | 2403 ft |
| K034D | N47.45424 W102.72398 | | K075D | N47.47355 W102.76364 | 2314 ft |
| K035D | N47.45644 W102.71626 | 2266 ft | K076D | N47.48180 W102.76124 | 2285 ft |
| K036D | N47.45101 W102.72035 | 2295 ft | K077D | N47.47889 W102.76664 | |
| K037D | N47.45043 W102.72980 | 2267 ft | K078D | N47.47695 W102.77139 | 2307 ft |
| K038D | N47.45091 W102.73683 | 2316 ft | K079D | N47.47165 W102.77209 | 2316 ft |
| K039D | N47.44850 W102.74249 | 2295 ft | K080D | N47.47917 W102.76185 | |
| K040D | N47.44557 W102.74070 | | Klatt No. 31-14 surface | N47.47164 W102.74444 | |
| K041D | N47.44595 W102.72866 | 2293 ft | Klatt No. 31-14 BH | N47.44656 W102.75011 | |

To provide an accurate average and standard deviation (or uncertainty) for the volumetric fluid distribution, a Monte Carlo analysis was performed. The existing background noise level in the data was calculated by estimating the signal during a "quiet" period of time prior to or after the fracture treatment when no fracturing was occurring in the area. The measured tilt at each site was then modified by randomly introducing a noise vector based on the calculated background noise level. The tilt at each site was modified, and an inversion routine found the fracture parameters that best fit the modified tilt data set. The original measured tilt at each site was then randomly modified again and re-inverted to find the best fit solution. This step was repeated many times (a minimum of 100) until the mean and standard deviations stabilized. **Figure 6** is a graphical representation of this process. Error analyses for the two stages along the toe, middle and heel of the lateral are presented in **Table 1**.

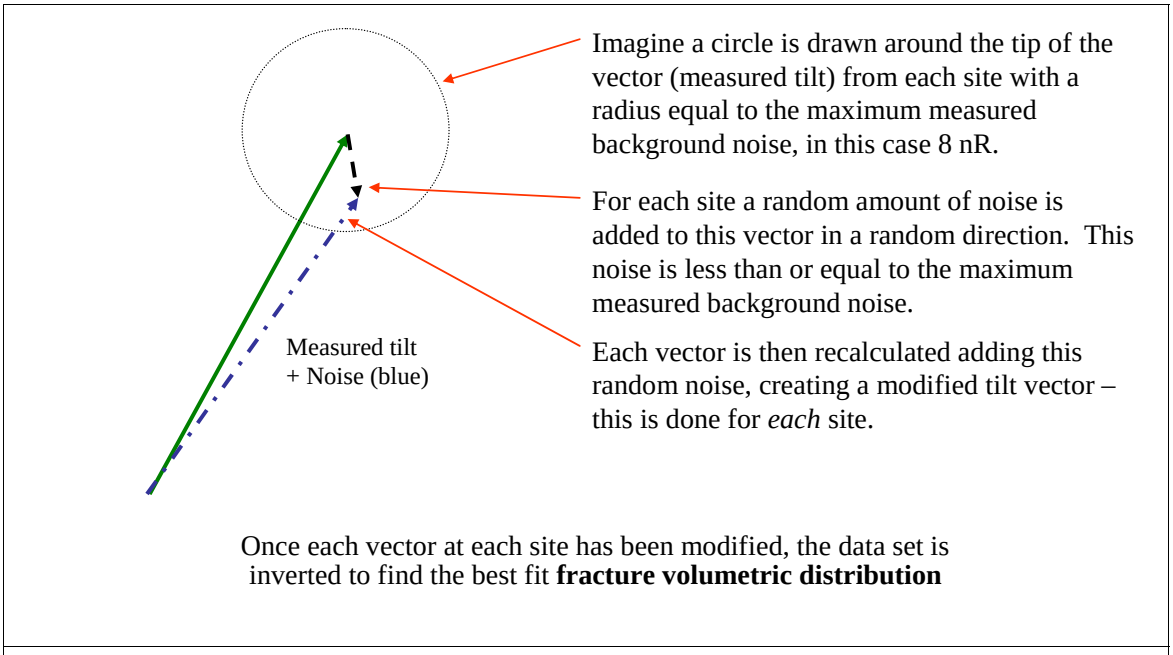



**Figure 6. Monte Carlo analysis visualization for best fit of fracture volumetric distribution**

### 3.2.1 Stage 1, First 40 Minutes (Injection on 7/23/2007)

The frac on the Klatt No. 31-14H produced a tilt response substantial enough that the confidence in the analysis associated with it was high. **Figure 7** and **Figure 8** are examples of raw tilt data from two of the sites surrounding the stimulated well. There was uneven, immediate and substantial fluid exit at the toe of the lateral in a transverse direction, approximately N88°W. By the end of the first 40 minutes of the treatment, about 40% of the fluid had exited at the heel – 40% in the middle (longitudinally) and the 20% balance at the heel. **Figure 9** presents a surface deformation visualization for the first 40 minutes of the treatment. Note that the deformation diagram represents the theoretical best-fit smoothed tilt from all the sites that were analyzed, and not the actual tilt measured from each of the individual sites. **Figure 10** and **Figure 11** are representations of the approximate positioning of the dominant transverse activity at the heel. The lengths of the various ellipses do not necessarily correspond to fracture half-length, as this parameter is not easily estimated by surface tilt technology.

A crosslinked fluid was pumped on this stage. Historically, the use of crosslinked fluids has produced a stronger tilt response for a given depth and pump rate than lower rate.

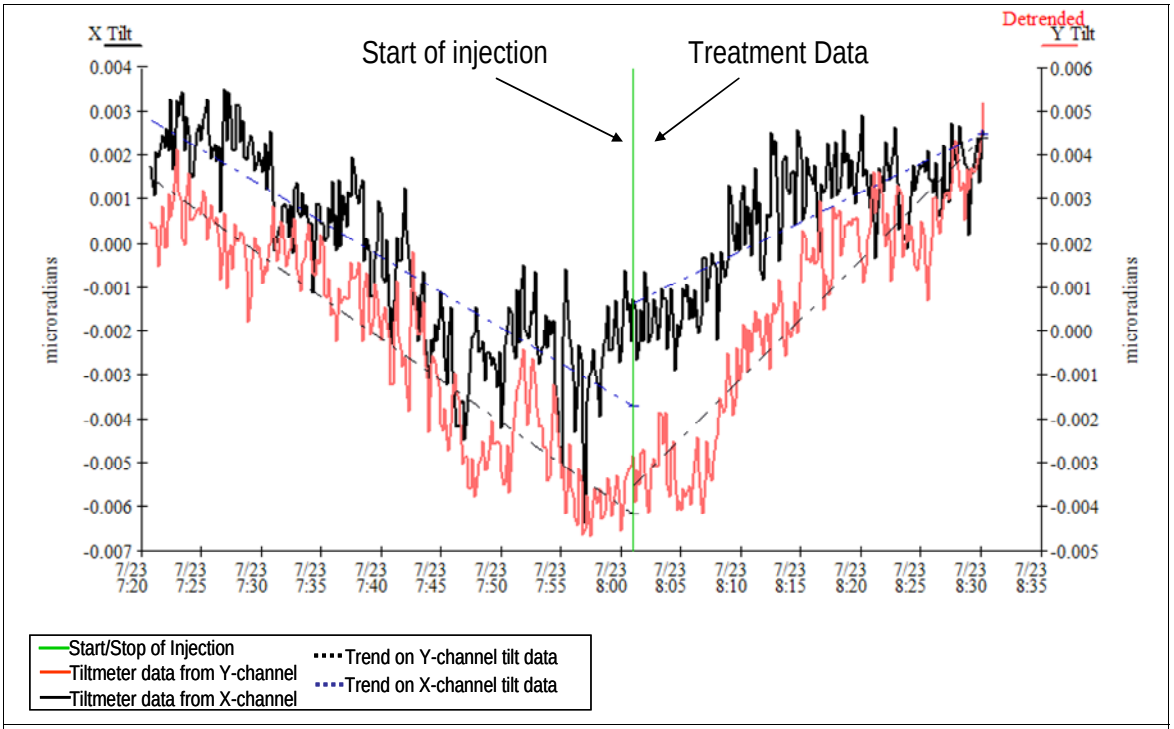



**Figure 7. Klatt No. 31-14H example of raw tilt data from site K016, stage 1**

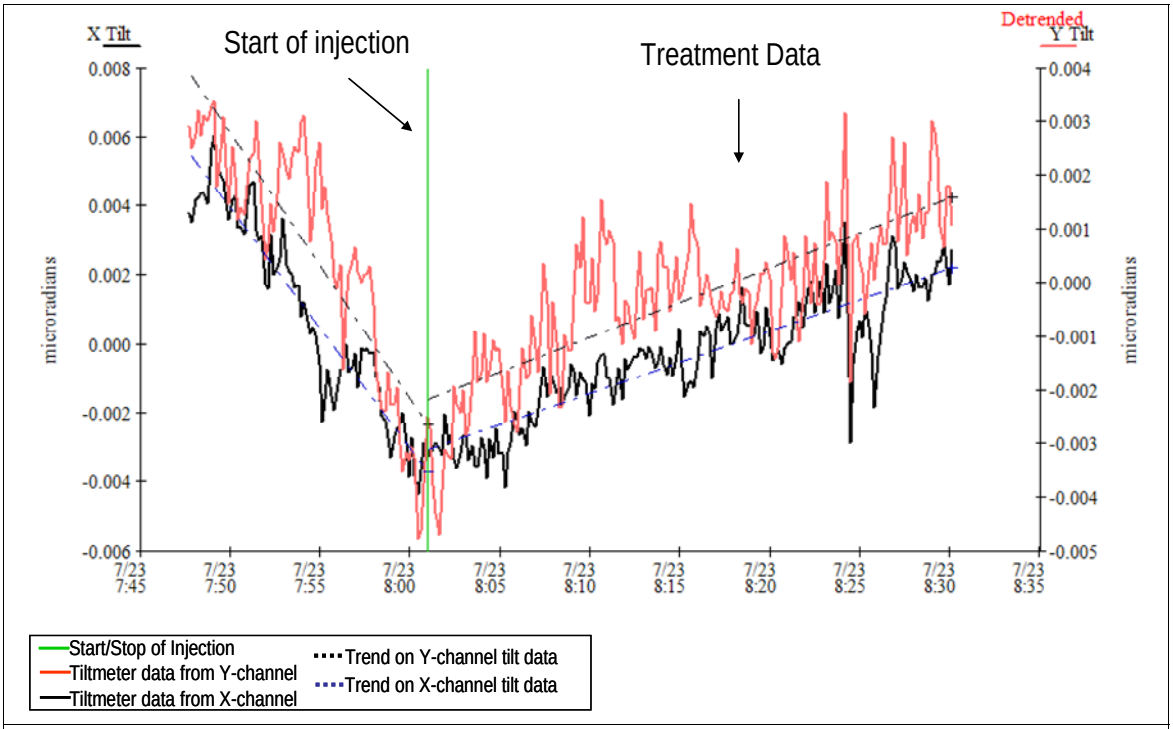



**Figure 8. Klatt No. 31-14H example of raw tilt data from site K031, stage 1**

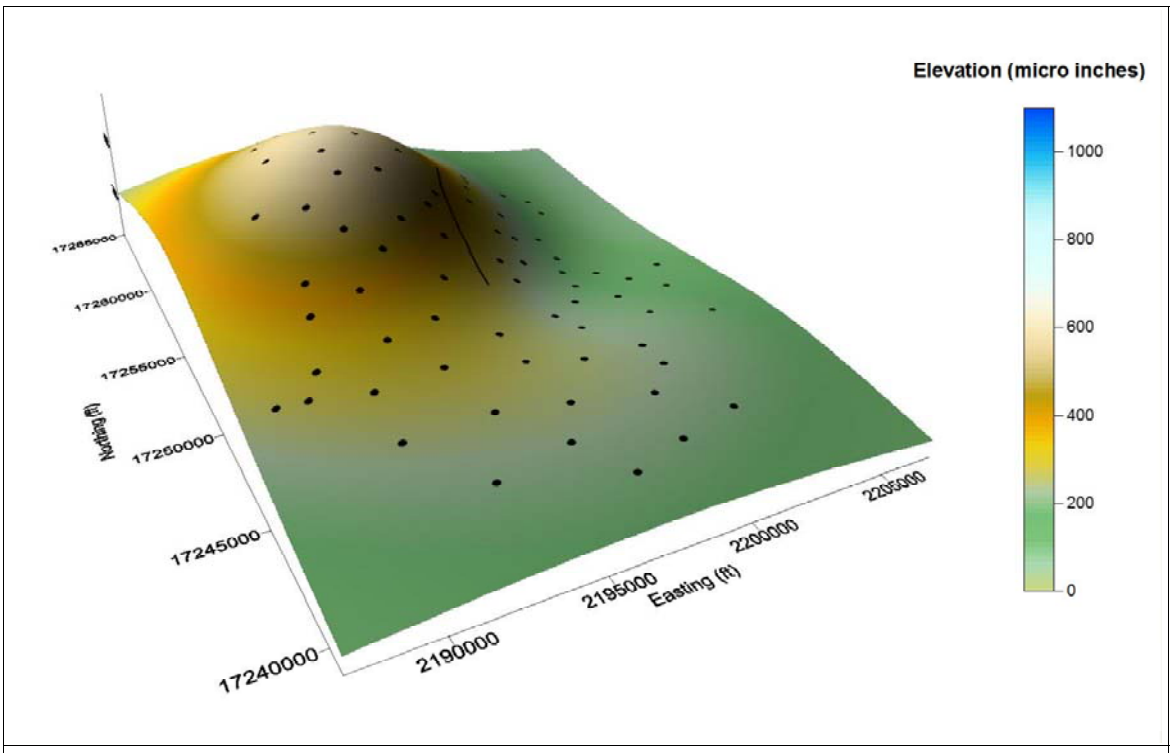



**Figure 9. Klatt No. 31-14H surface deformation diagram, first 40 minutes, stage 1**

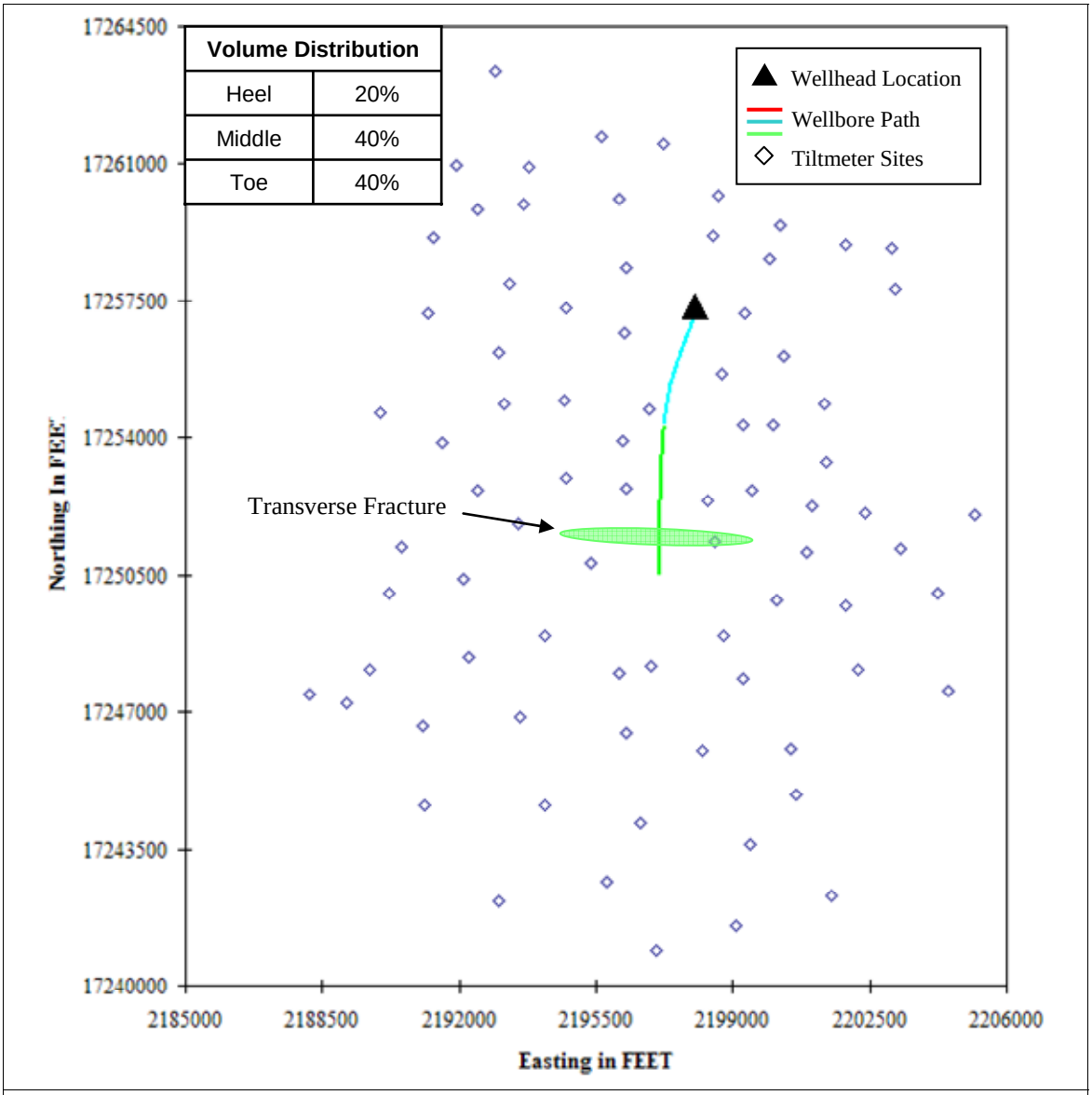



**Figure 10. Klatt No. 31-14H map view visualization, first 40 minutes, stage 1**

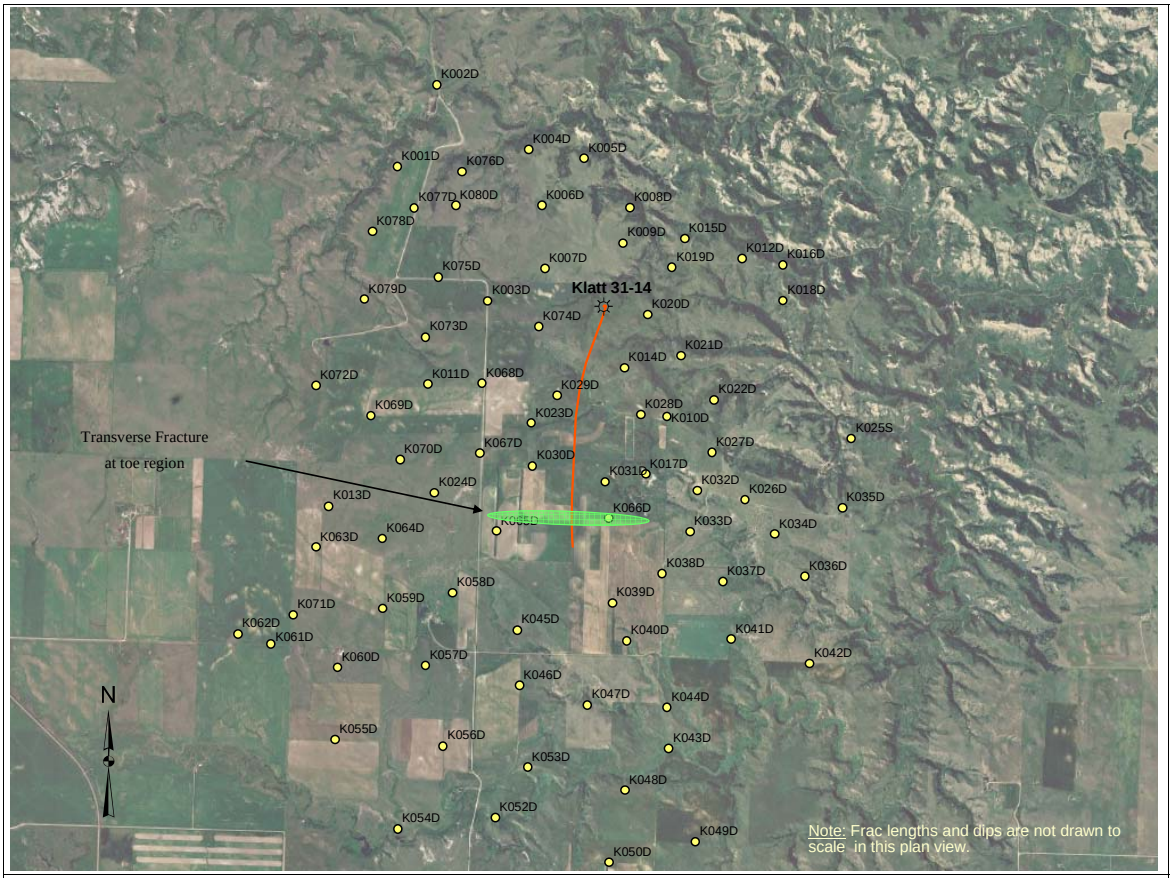



**Figure 11. Klatt No. 31-14H map view visualization overlaid on area photo, first 40 minutes**

### 3.2.2 Stage 1 from Start to Casing Failure (Injection on 7/23/2007)

The change in tilt was measured again, this time at the end of the treatment, and the volume distribution across the entire treatment was analyzed. An example of raw data off site K036 shows that the change in tilt from beginning to end was substantial, resulting in a relatively high degree of confidence in the results (**Figure 12**). **Figure 13** is a surface deformation image that takes into account the entire treatment, and again, is a representation of the theoretical tilt calculated from a smoothing of the actual tilt from the individual sites.

The toe portion of the lateral accepted 50% of the total stage fluid volume. Of that 50%, 30% were transverse and 20% were longitudinal. The middle section of the lateral accepted 40% of the fluid (15% transverse, 15% longitudinal, and about 10% horizontal). The heel portion accepted about 10% of the fluid, most of which had characteristics consistent with horizontal fractures. Overall, 45% were transverse, 35% were longitudinal, and 20% were horizontal.

Classical fracturing theory proposes that cylindrical openholes exposed to pressures higher than the maximum principle stress initiate fracturing in the longitudinal direction, regardless of the direction of maximum and least principle stress. The presence of both longitudinal and transverse fractures in the same wellbore, then, could suggest that even though the direction of maximum principle stress is likely perpendicular to the Klatt No. 31-14H, the magnitude of that stress could have been somewhat greater in the middle portion of the lateral than on either end.

A crosslinked fluid (Halliburton's SilverStim™ was pumped on this stage. Historically, the use of crosslinked fluids has produced a stronger tilt response for a given depth and pump rate than lower viscosity fluids. It has also been noted that, for cases where natural fracturing or planes of weakness are present, crosslinked fluids tend to create "simpler" fracture networks than do low-viscosity systems.

**Figure 14** and **Figure 15** are map-view representations of the approximate volumetric distribution of fluids as measured by surface tilt response over the entire first stage, from start of pumping until the casing failed, and the stage was prematurely terminated.

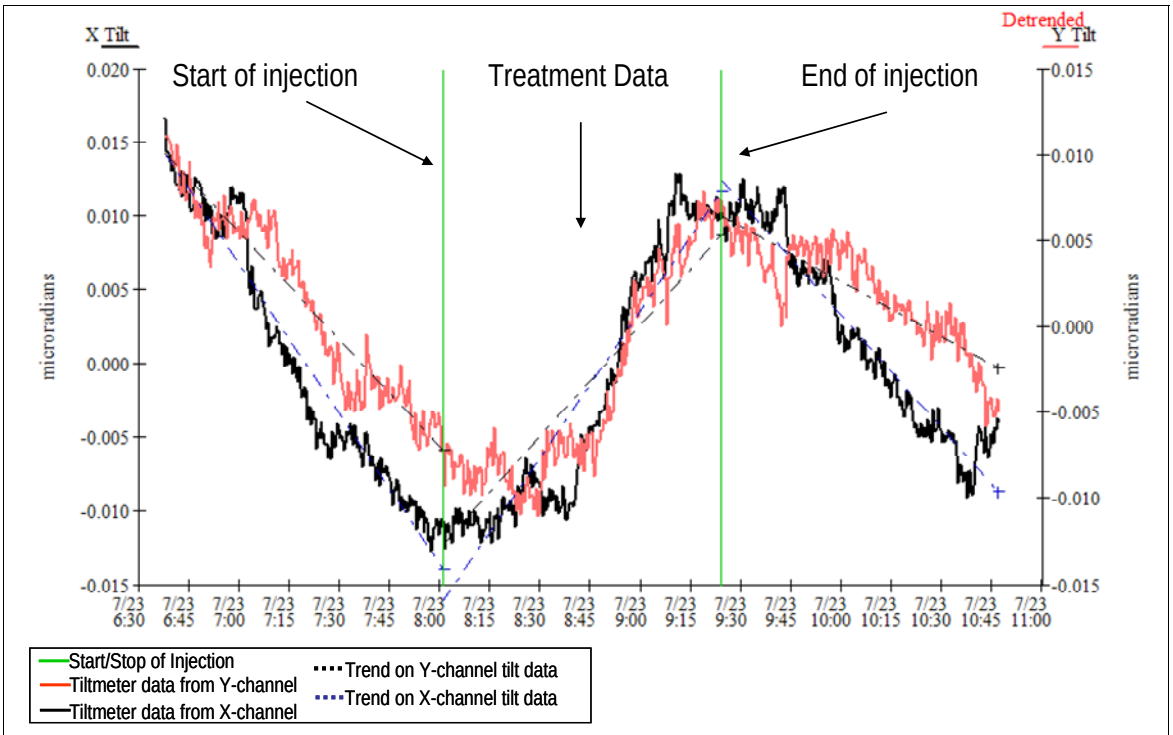



**Figure 12. Klatt No. 31-14H example of raw tilt data from site K036, stage 1**

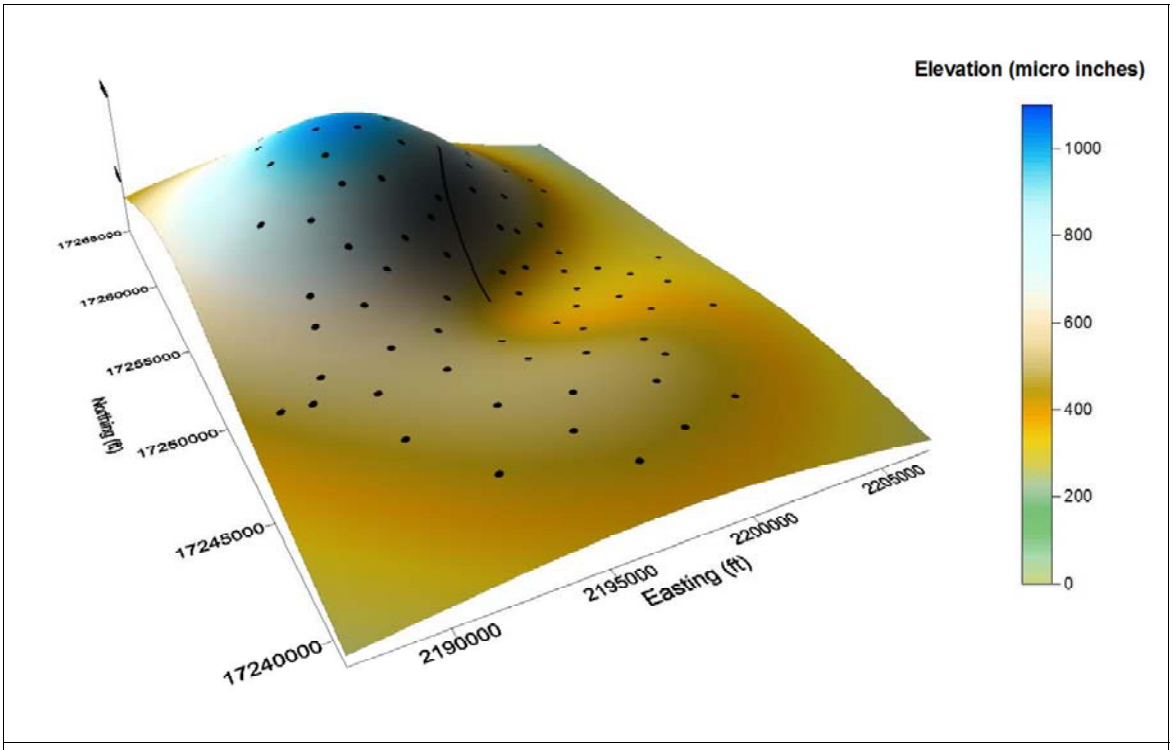



**Figure 13. Klatt No. 31-14H surface deformation diagram, entire first stage**

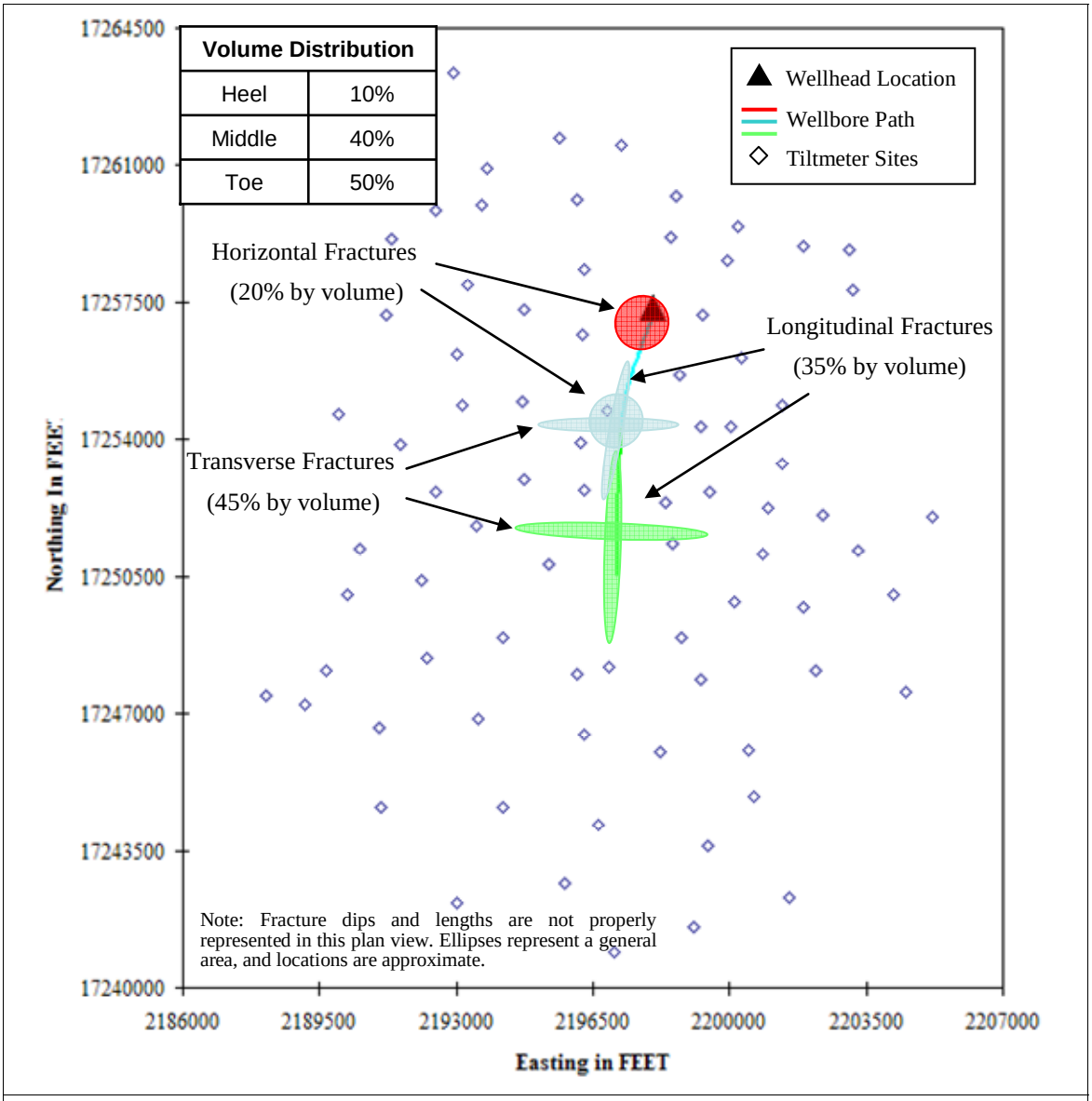



**Figure 14. Klatt No. 31-14H map view visualization, entire first stage**

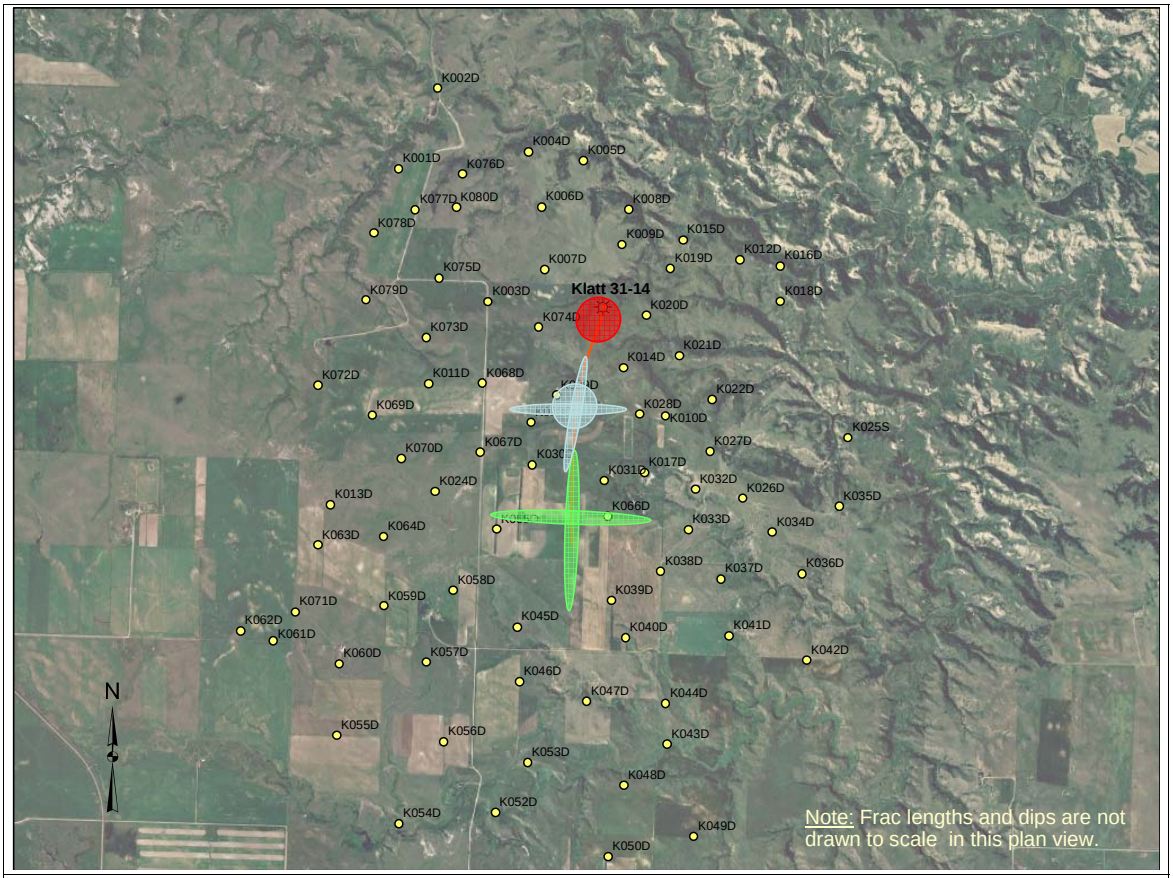



**Figure 15. Klatt No. 31-14H map view visualization overlaid on area photo, entire first stage**

### 3.2.3 Stage 2 from Initiation to Flush (Injection on 9/5/2007)

Stimulation philosophy was altered substantially on the second attempt. Instead of a [high apparent viscosity] crosslinked fluid, the stage was designed for slickwater, (average about 2 to 3 cps) in order to potentially promote more induced fracture complexity and therefore expose more total reservoir to the lateral via propped fractures. More volume was pumped (6,553 bbl vs. 3,892 bbl during stage 1), and higher rate was employed (61 bpm vs. 48 bpm).

**Figure 16** and **Figure 17** are examples of raw data off sites K023 and K029, and these again indicate that the change in tilt from beginning to end was substantial, resulting in a relatively high degree of confidence in the results. **Figure 18** is a surface deformation image that takes into account the entire treatment, and like stage 1, is again a representation of the theoretical tilt, calculated from a smoothing of the actual tilt from the individual sites.

Though fluid distribution was still uneven along the lateral, it is evident that substantially more total reservoir was treated during this stage. The potential root causes for this are several, but it is probable that radically lower fluid viscosity, higher pump rate, and stress shadowing associated with the higher total volume are all at, or near, the top of the list.

The toe portion of the lateral accepted 25% of the total stage fluid volume. Of that, 15% were oblique (N45°W) and 10% were longitudinal. The middle section of the lateral accepted 30% of the fluid; all fracture(s) appeared to be longitudinal. The heel portion accepted about 45% of the fluid, all of which had characteristics consistent with transverse fracture(s).

**Figure 19** and **Figure 20** are map-view representations of the approximate volumetric distribution of fluids as measured by surface tilt response over the entire first stage.

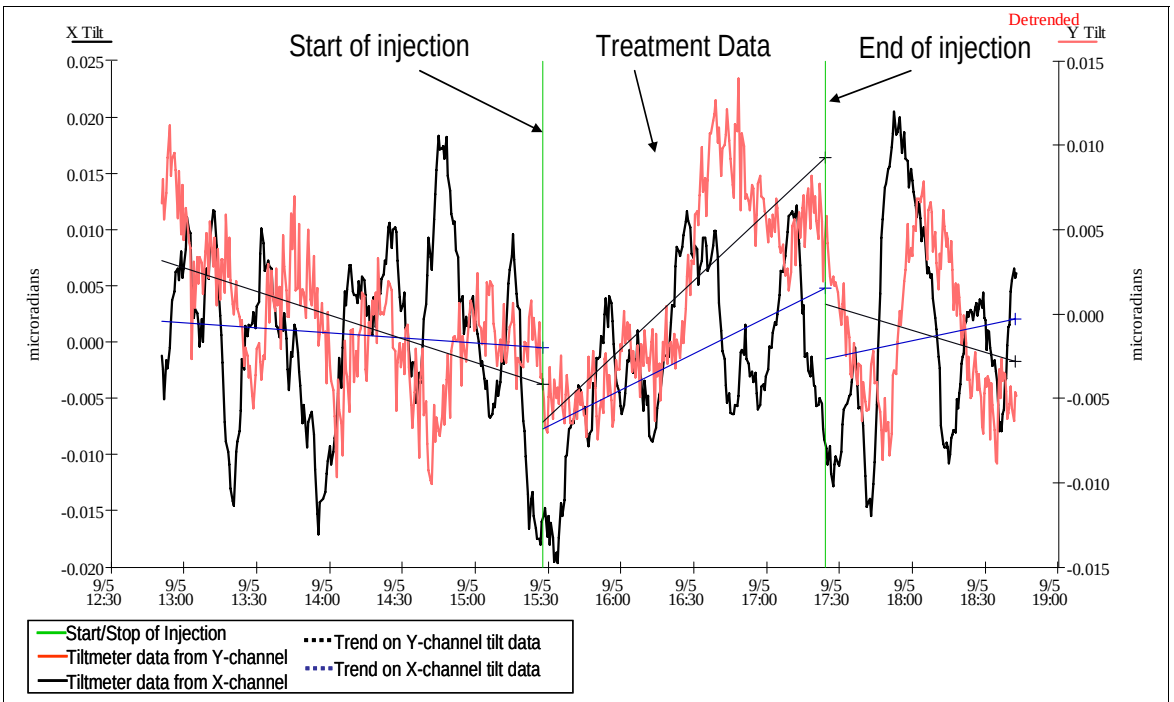



**Figure 16. Klatt No. 31-14H example of raw tilt data from site K023, stage 2**

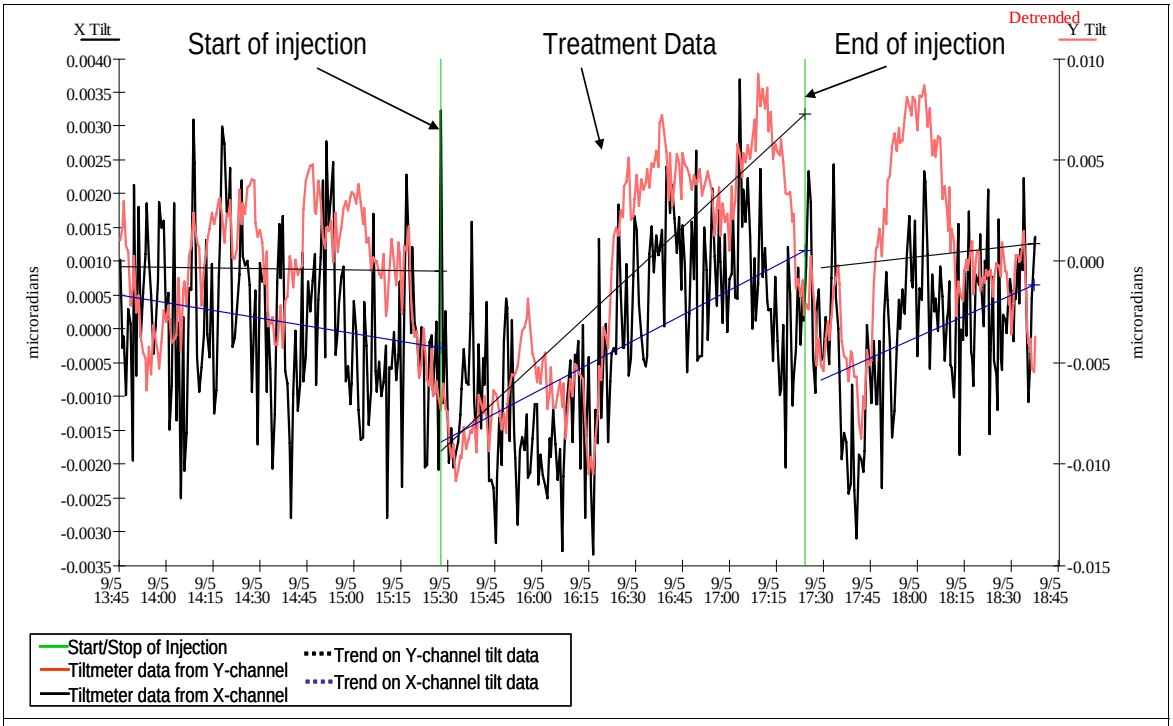



**Figure 17. Klatt No. 31-14H example of raw tilt data from site K029, stage 2**

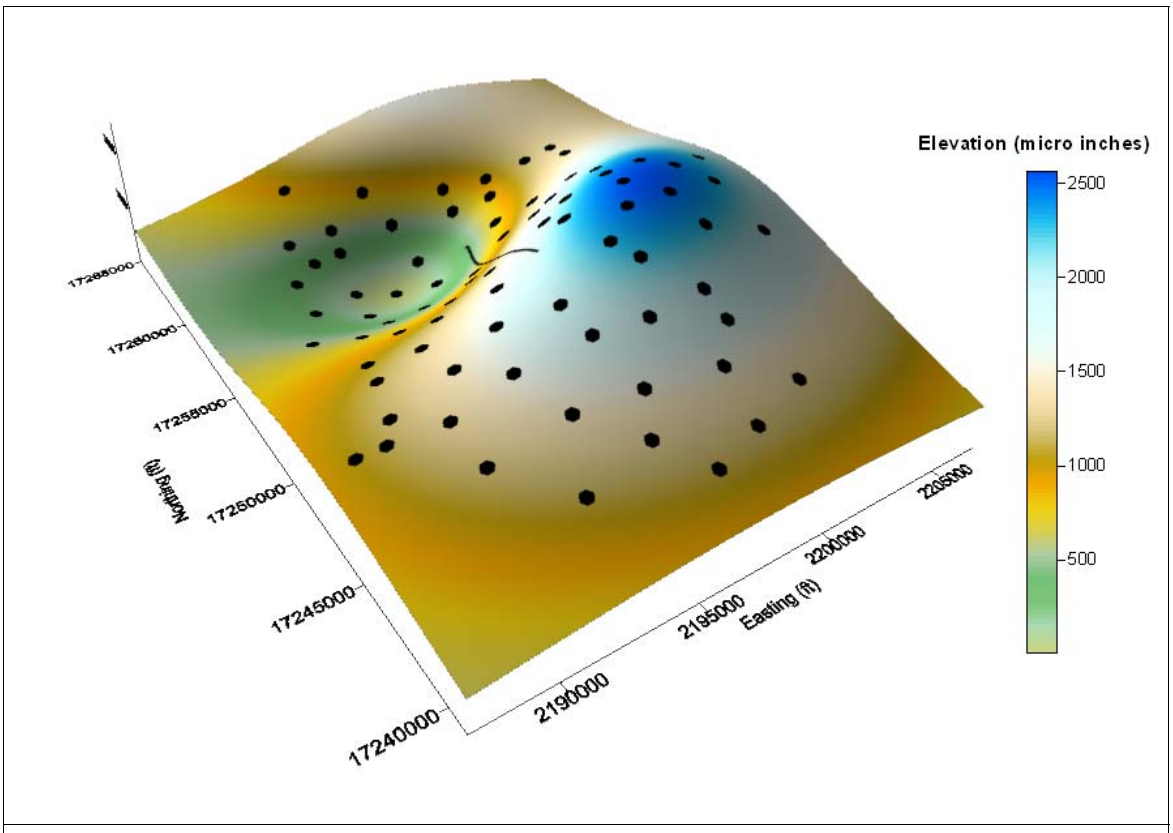



**Figure 18. Klatt No. 31-14H surface deformation diagram, stage 2**

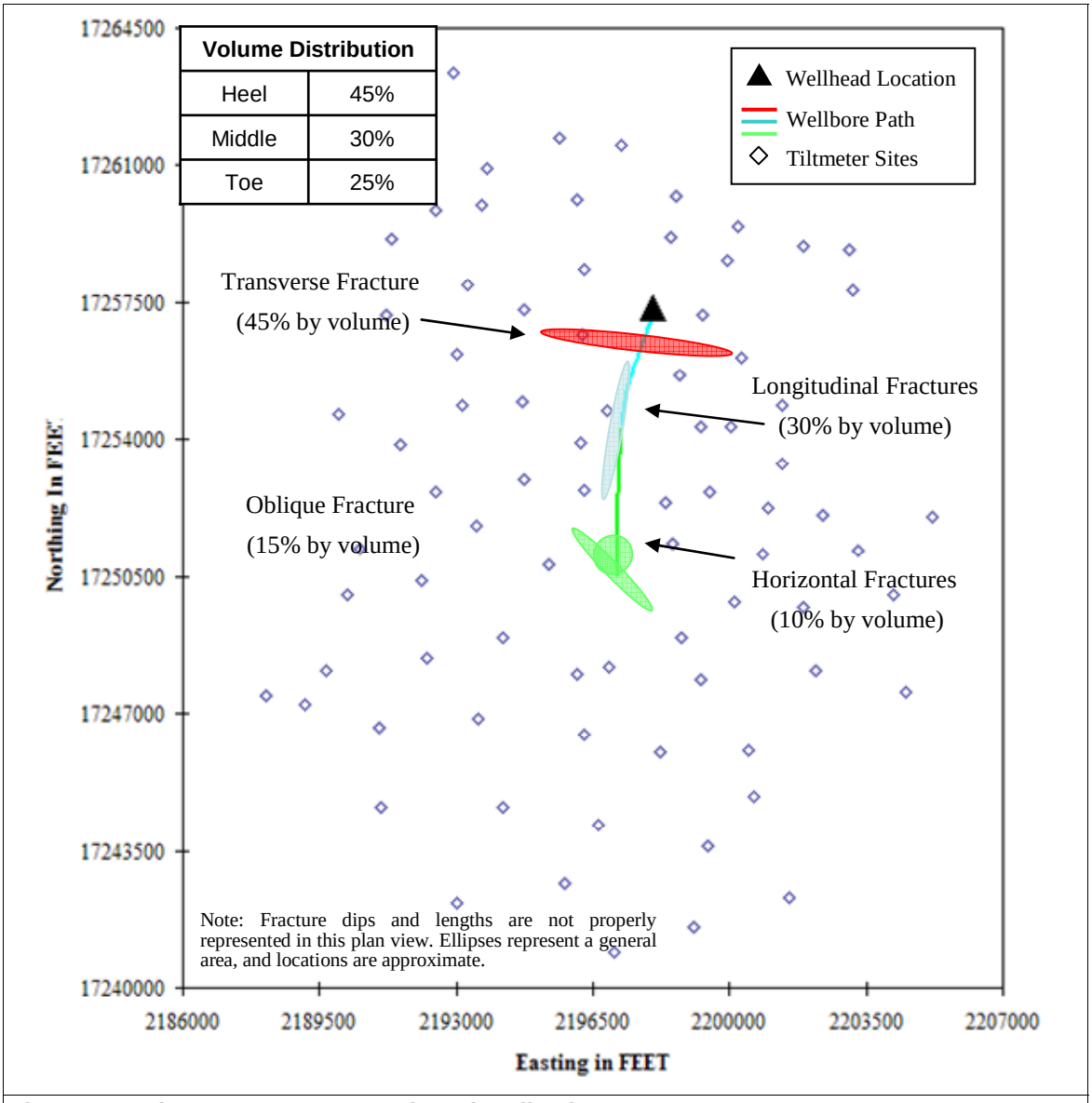



**Figure 19. Klatt No. 31-14H map view visualization, stage 2**

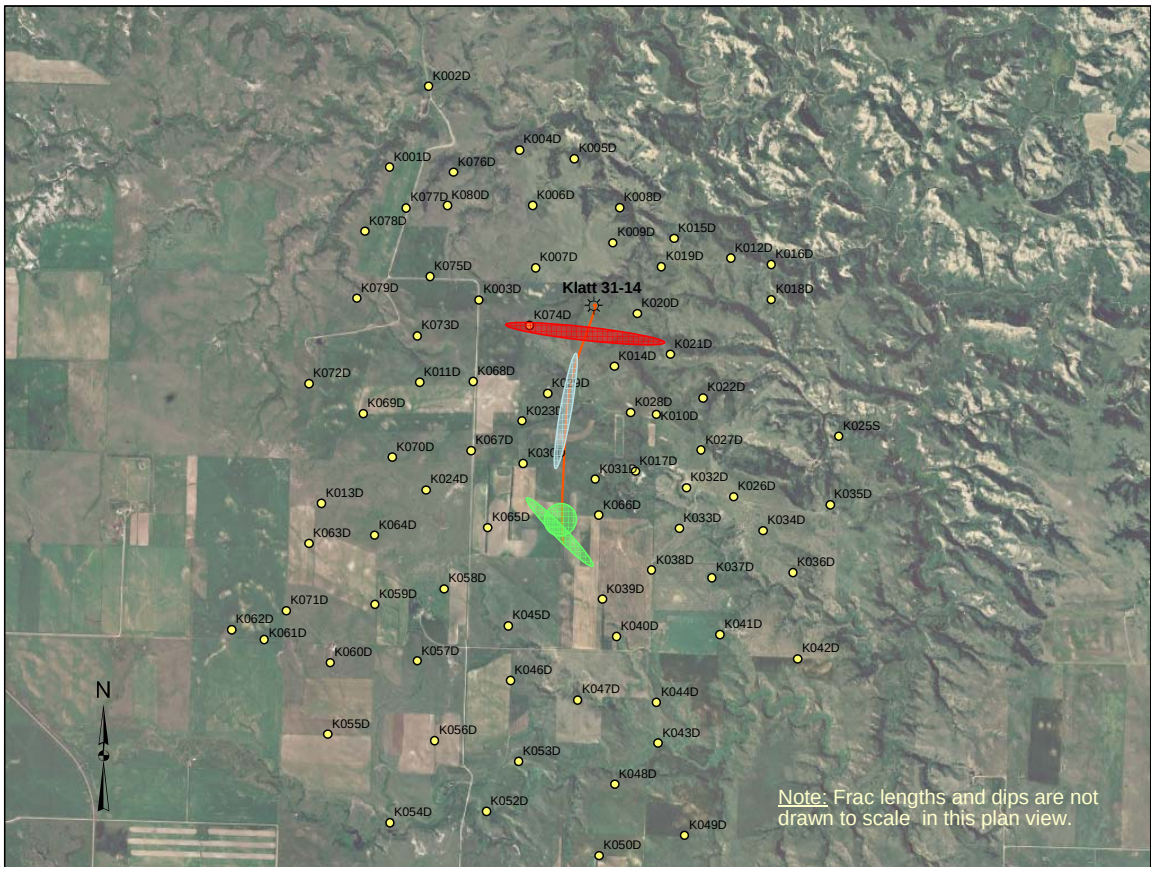



**Figure 20. Klatt No. 31-14H map view visualization overlaid on area photo, stage 2**

## 3.3 Fracture Treatment Data

### 3.3.1 Treatment Record, Stage 1

On 7/23/2007, Halliburton pumped the first stimulation attempt. The treatment was designed consistent with other Bakken play treatments, but assumed a relatively high permeability in the middle section of the column between the two shales. The design included a very conductive fracture, in anticipation of extreme pressure drops down the fracture pack itself, and concentrations of up to 10 ppg were actually pumped.

The treatment was terminated early, when either the wellhead isolation tool failed or the casing failed at or below the hanger. A total of 3,892 bbl and 296,000 lb of proppant was pumped, at about 48 bpm. Surface treating pressures, rates, and concentrations are shown as functions of treating time in **Figure 21.**

After discussion of STM results and the obvious low permeability to fracturing fluid associated with this operation, a new treatment was designed that was intended to create longer fractures, more network complexity, and possibly treat new reservoir that was not treated on this stage.

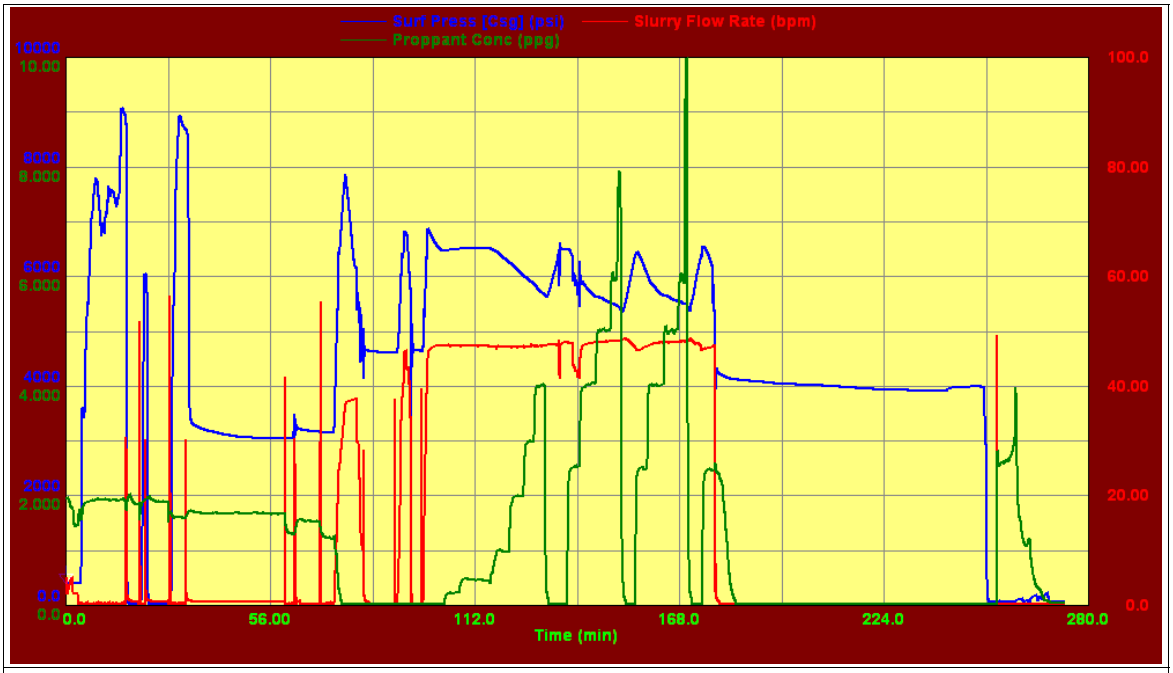



**Figure 21. Klatt No. 31-14H treatment record, stage 1**

### 3.3.2 Treatment Record, Stage 2 (9/5/2007)

Stage 2 (the second stimulation attempt across the same completion) was performed on 9/5/2007 by Halliburton Services. After discussion regarding the first stage leakoff and STM results, it was decided that a stimulation design more appropriate for an ultra-low-permeability scenario would be attempted on the re-frac. Though the treatment was designed for more than was actually pumped, and did screenout, it was reasonably close to design. Average rate was 61 bpm, and a total of 6,553 bbl and 193,000 lb of proppant was pumped, this time at an average rate of about 0.63 ppg. The treatment was pumped to completion without any major mechanical failures. Surface treating pressures, rates, and concentrations are shown as functions of treating time in **Figure 22**.

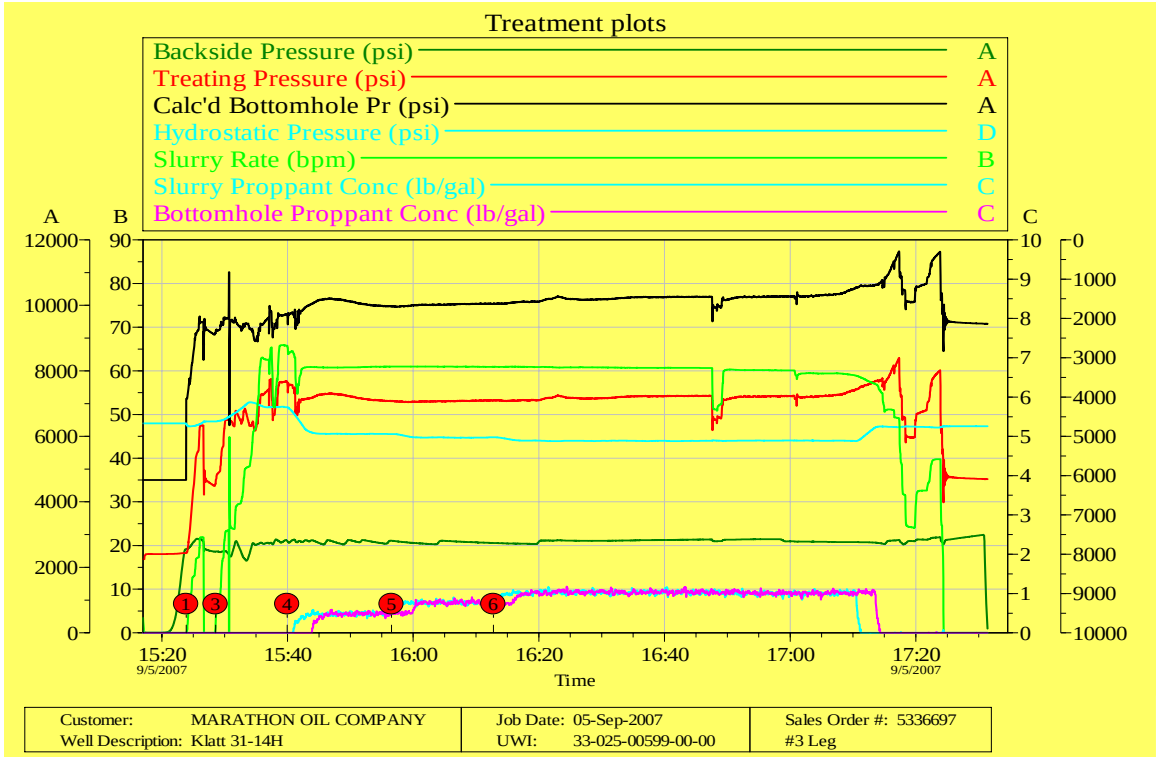



**Figure 22. Klatt No. 31-14H treatment record, stage 2**

# Appendix A—Surface Tiltmeter Fracture Mapping

## Tiltmeter Fracture Mapping

Creation of a hydraulic fracture, by definition, involves parting of the rock and displacing the fracture faces to create fracture width. The principle of tiltmeter fracture mapping is simply to infer hydraulic fracture geometry by measuring this fracture-induced rock deformation. The induced deformation field radiates in all directions and can be measured either downhole with wireline-conveyed tiltmeter arrays or with a surface array of tiltmeters. **Figure 23** shows a schematic diagram of the induced deformation field from a vertical fracture as seen both downhole and at the surface. As shown, measuring the deformation field at the surface with a two-dimensional array gives a very different view of the deformation field than a one-dimensional (line) array downhole in an offset wellbore.

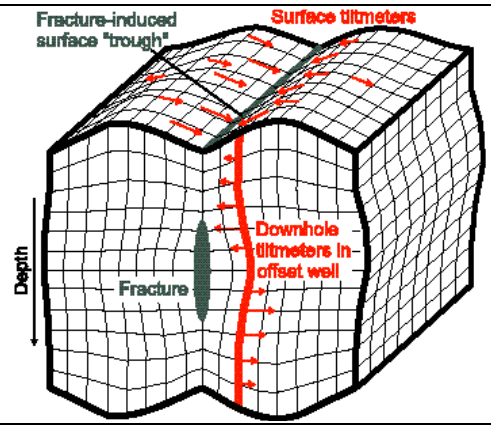



**Figure 23. Principle of tiltmeter fracture mapping**

At the surface, the induced deformation magnitudes are so small – typically of order one ten-thousandth of an inch – that they are impossible to measure. Fortunately, measuring the gradient of the displacement field, or the tilt field, is far easier. The induced deformation field at the surface is primarily a function of fracture azimuth, dip, depth to fracture center, and total fracture volume (**Figure 24**). The induced deformation field is almost completely independent of reservoir mechanical properties and *in situ* stress state. For example, a north-south growing vertical hydraulic fracture of a given size yields the same surface deformation pattern whether the fracture is in low modulus diatomite, extremely hard carbonate, or even unconsolidated sandstone. The deformation pattern is simply a north-south trending trough surrounded by symmetrical ridges (the ridges are asymmetrical if the fracture is dipping) whose magnitude depends on the created fracture volume and whose separation depends on the depth-to-fracture-center.

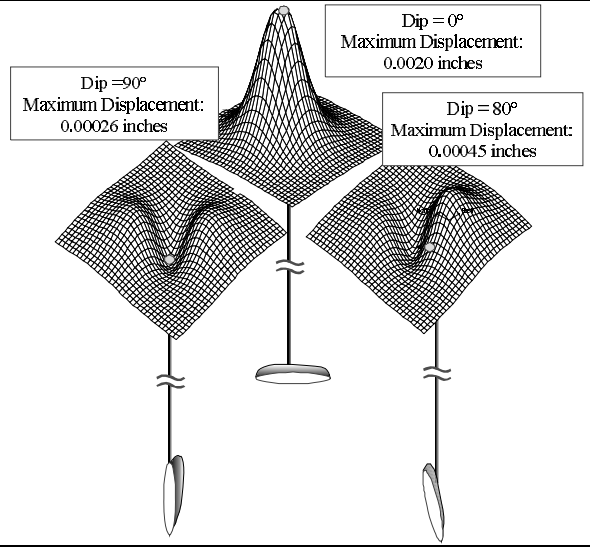



**Figure 24. Surface deformation for hydraulic fractures of different orientations at 3,000 feet depth**

The simplicity of the concept allows robust and unambiguous determination of a few primary fracture parameters like fracture azimuth and dip and, with somewhat less precision, created fracture volume, depth-to-fracture-center and fracture offset due to asymmetric growth. The characteristic shape and orientation of the tilt field is not altered with increasing fracture depth. The magnitude of the tilt is, of course, attenuated with increasing fracture depth, which serves to limit the practical surface mapping depth.

The greatest limitation of surface tilt mapping is that some critical details, like individual fracture dimensions, cannot be resolved at fracture depths far greater than the created fracture dimensions. This is because at greater depth not only do the induced surface tilts get smaller, but there is also an inherent blurring of the fracture source "edges" as the measurement distance gets large compared to the separation of the fracture edges (i.e., fracture dimensions). Downhole tiltmeter mapping was developed to get around the fracture dimension resolution limitation by bringing the measurement distance down to the same order of magnitude as the created fracture dimensions.

## How Surface Tilt Mapping Works

Surface tiltmeter mapping involves measuring the fracture-induced tilt at many points above a hydraulic fracture, and then solving the geophysical inverse problem to determine the fracture parameters that must have been created in order to produce the observed deformation field. While the concept is simple, the magnitudes of the induced surface deformations are quite small and require highly sensitive measurement. A typical hydraulic fracture treatment at 7,000 ft depth results in induced surface tilts of only about ten nanoradians – or about ten parts in a billion. These minute tilts are measured with highly sensitive tiltmeters that operate on the same principle as a carpenter's level. Tiltmeters are metal cylinders roughly 30 inches long and 2 inches in diameter, which measure their own tilt on two orthogonal axes. As the instrument tilts, a gas bubble contained within a conductive liquid-filled glass casing moves to maintain its alignment with the local gravity vector. Precision electronics detect changes in resistivity between electrodes mounted on the glass sensor that are caused by motion of the gas bubble. The latest generation of high-resolution tiltmeters, developed jointly by Pinnacle Technologies and

Lawrence Livermore National Laboratory, were awarded a prestigious *R & D 100 Award* in 1997 and can detect tilts of less than one nanoradian.

For fracture mapping purposes, an array of 12 to over 24 tiltmeters is placed around the well to be fractured at radial distances from 15% to 75% of the fracture depth, as this is the region of maximum induced surface tilt. Fortunately, the exact layout of the monitoring array is not critical. Fracture mapping resolution is primarily dependent on the number of tiltmeter sites employed and the signal-to-noise ratio of the measurements. Resolution of fracture orientation is typically better than +/- 5 degrees at depths less than 5,000 feet and can drop to +/- 10 degrees as depth approaches 10,000 feet. Resolution of fracture center location ranges from 20 to 200 feet for fractures shallower than 3,000 feet and drops to many hundreds of feet for fractures approaching 10,000 feet.

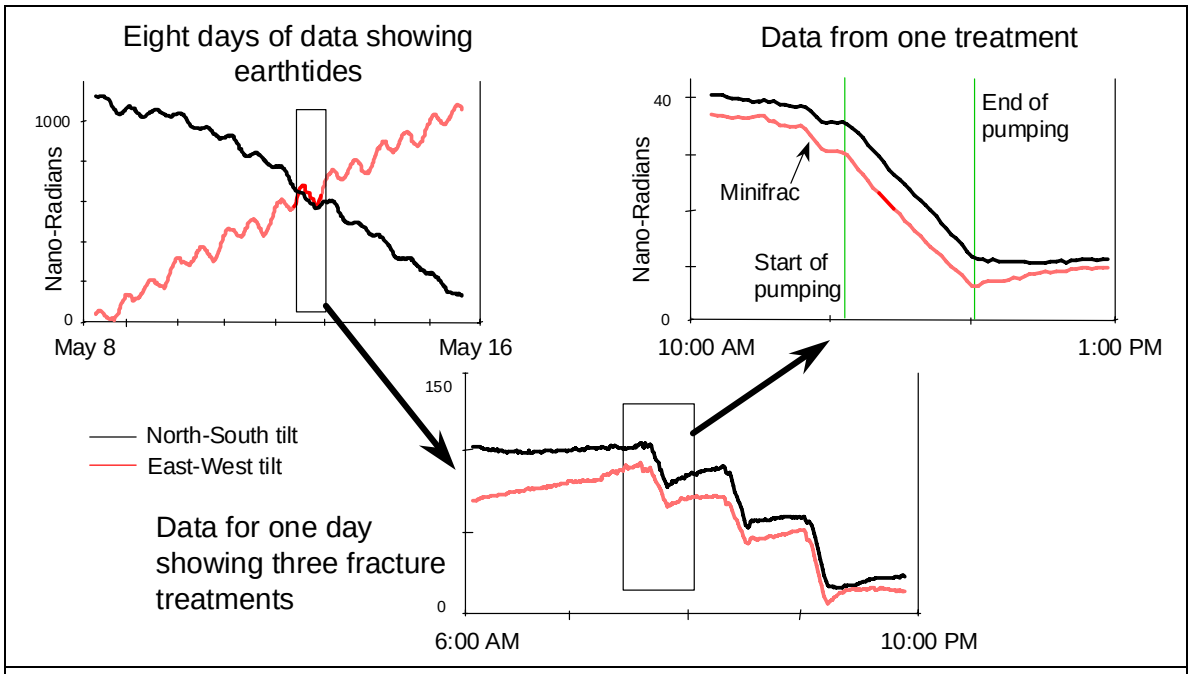
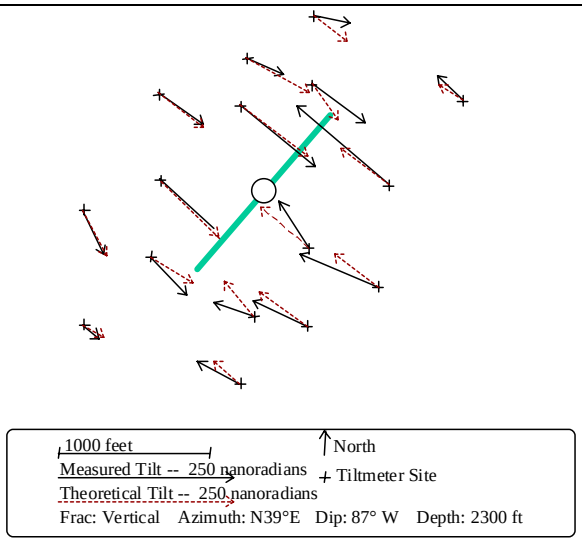



**Figure 25. Three pictures of raw tiltmeter data on different time scales, ranging from one week with clear earth tides to a few hours around a fracture treatment**

Each tiltmeter site has an instrument surrounded by sand within PVC pipe (3" to 9" diameter) that is cemented in a relatively shallow (10 to 40 feet deep) borehole. **Figure 25** shows a sample record of tilt data versus time on many different time scales. The first view shows the daily swings of the tilt data in response to the solid earth tides caused by the earth's rotation with respect to the sun and moon, and a long-term drift due to surface subsidence. The next zoom-in shows an 18-hour time period when three hydraulic fracture treatment stages (seen clearly in the data) were pumped in the well being monitored. The final zoom-in shows a two-hour time period that clearly shows the recording of fracture-induced tilt from one of the propped fracture treatments. The three fracture treatments shown were in a relatively shallow depth range of approximately 3,000 feet and hence yielded induced tilts of order 100 nanoradians. The fracture-induced tilt is then extracted at each instrument site to yield an array of observed surface tilt vectors.

The observed tilt data is inverted to find the hydraulic fracture parameters that yield the best fit to the observed data, and a Monte Carlo technique is employed to estimate parameter uncertainty. The upper portion of **Figure 26** compares the observed and theoretical fracture-induced tilt vectors from a best-fit fracture solution and shows a tabular listing of the mapped fracture orientation and depth. Note how a careful visual inspection of the observed tilt vectors alone reveals a trough that runs roughly northeast-southwest (fracture azimuth of N45°E) and that both ridges are of roughly equal magnitude implying a fracture dip that is almost perfectly vertical (90 degrees). In simple single-plane fracturing cases like this, visual inspection alone reveals the essential results.

The lower part of **Figure 26** shows another overlay of observed and theoretical tilt vectors for the case of a horizontal fracture. Note the dramatic difference in the induced surface tilt patterns. Curiously, the mapped horizontal hydraulic fracture is in the same field as the vertical frac shown, and the horizontal fracture is created in a structurally deeper part of the reservoir.



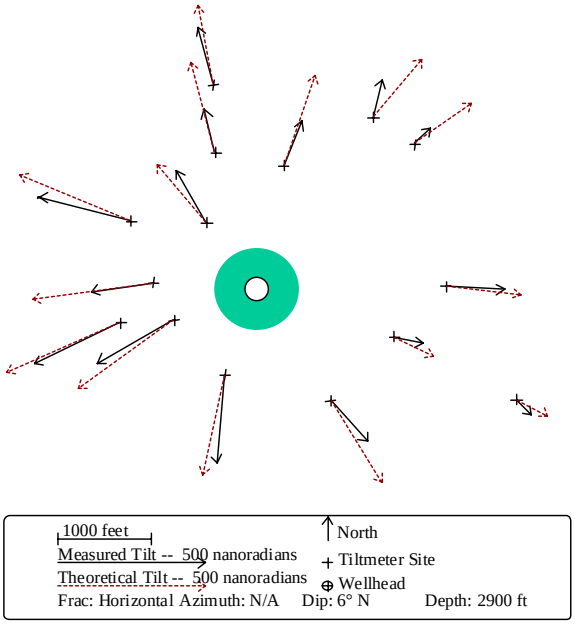




**Figure 26. Observed and theoretical fracture-induced tilt vectors for a vertical (top) and horizontal (bottom) fracture; Curiously, the mapped horizontal fracture is in the same field as the vertical fracture shown, and the horizontal fracture is created in a structurally deeper part of the reservoir**

As the fracture-induced tilt is measured as a function of time, fracture mapping can be performed throughout the course of the treatment (and soon, in real-time). In some cases, fractures may initiate in one plane and then twist into another orientation, or initiate secondary fracture growth in another plane at some point in time during a treatment. Other parameters like depth-to-fracture-center may also change significantly during a treatment if, for example, the fracture breaks through a barrier and begins rapid upward (or downward) height growth.

# Appendix B—Conventions Used in Describing Fracture Orientation

Conventions for describing fracture azimuth orientation are shown in **Figure 27**. In this example, azimuth is measured in degrees from due north. The last letter (E or W) specifies the direction of rotation from north (E is clockwise towards the east; W is counter clockwise toward the west).

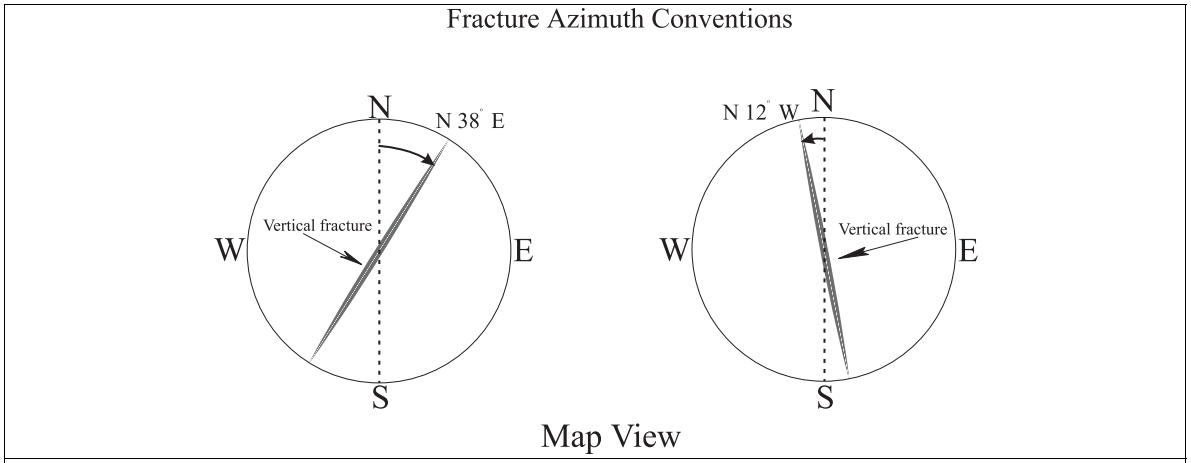



**Figure 27. Conventions for describing fracture azimuth orientation**

Conventions for describing fracture dip are shown in **Figure 28**. A horizontal fracture has a dip of zero degrees. A vertical fracture has a dip of 90°. The last letter designates which direction the fracture is dipping towards. For example, a fracture dip of 55°E should be understood as a fracture dipping 55° down towards the east. The range of possible dips (0° to 90°) has been divided into three descriptive groups – horizontal, dipping and vertical. This nomenclature helps describe fractures in Pinnacle reports. For example, a fracture with a dip of 82°E would be understood as a vertical fracture dipping 82° down towards the east.

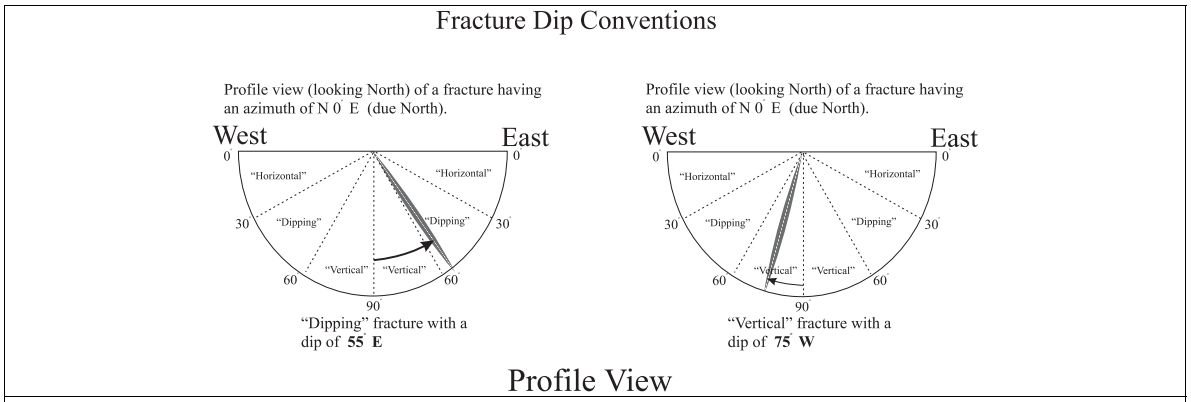



**Figure 28. Conventions for describing fracture dip**

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# Surface Tilt Fracture Mapping

## Real -Time Engineering Solutions

Fracture Mapping Reservoir Monitoring Engineering Services Modeling Software

# Principle of Tilt Fracture Mapping

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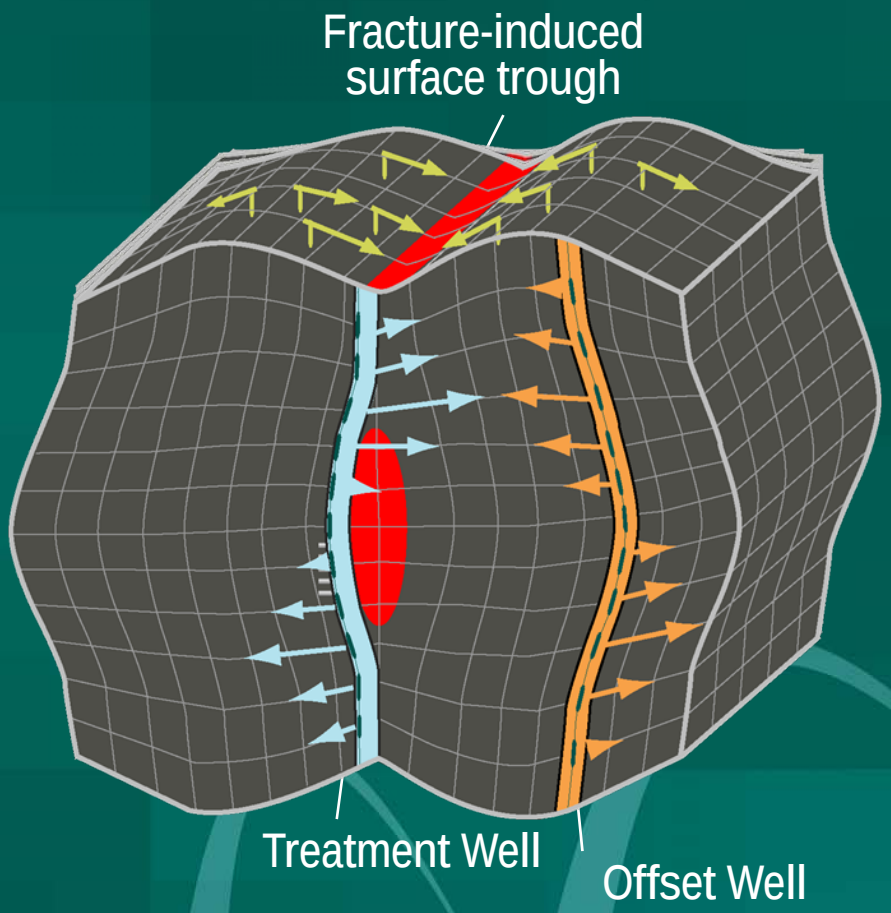
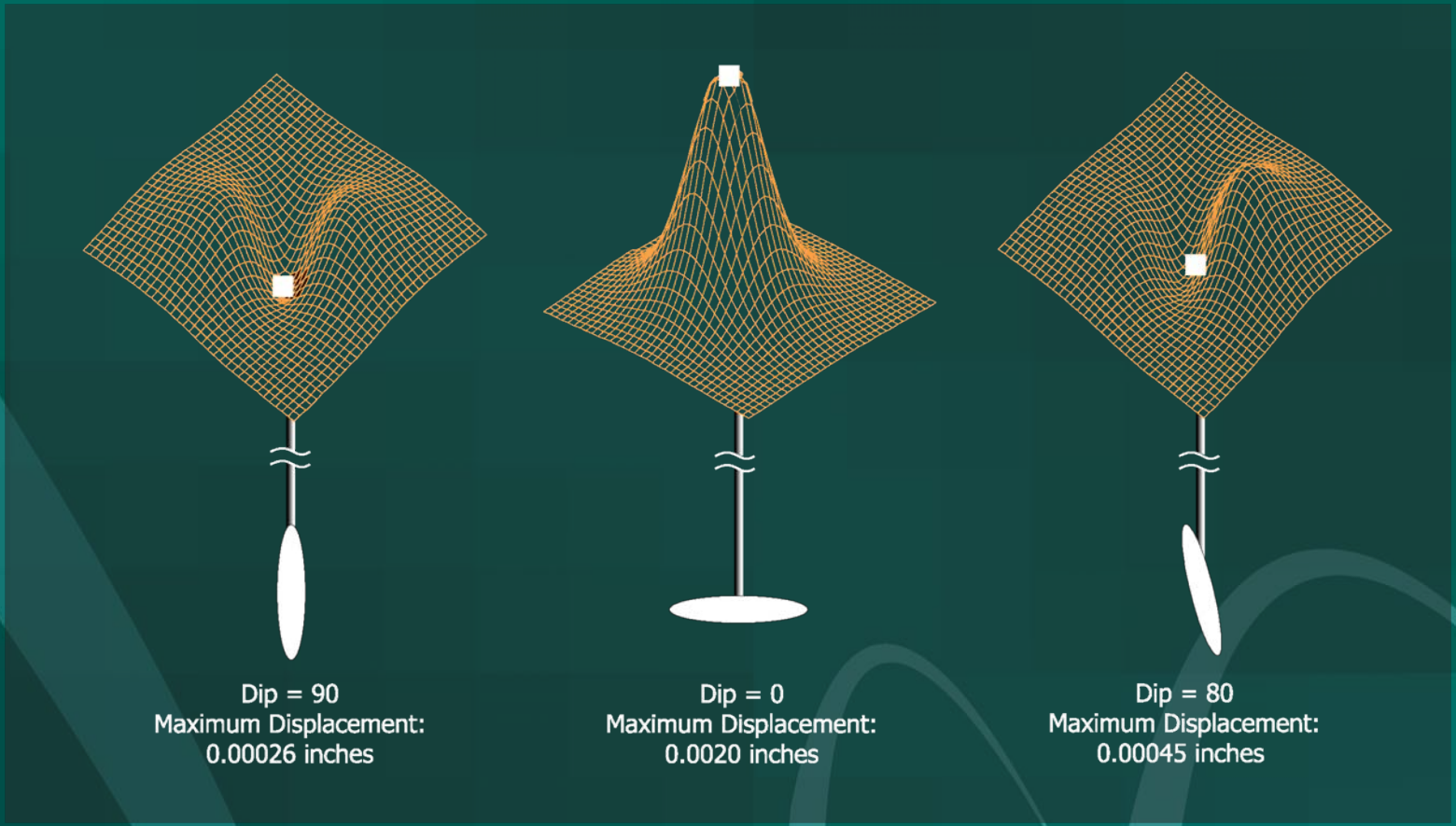
Hydraulic fracture induces a characteristic deformation pattern

Induced tilt reflects the geometry and orientation of created hydraulic fracture




**Surface and Treatment Well Tilt are Hart's Meritorious Award Winners

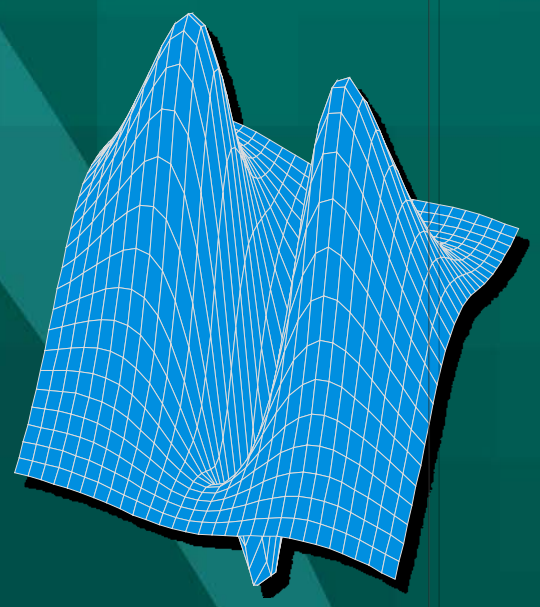
# Frac Orientation Easy to Visualize Even on Deep Reservoirs



# Unique Tilt Vector Patterns Reflect The Unique Deformation Patterns

Pinnacle

- Tilt vectors show “twin peaks” and “trough” characteristic of vertical fractures.



oblique view

map view

legend

1000 ft

Frac: Vertical

Azimuth: N39˚E

Dip: 87˚W

North

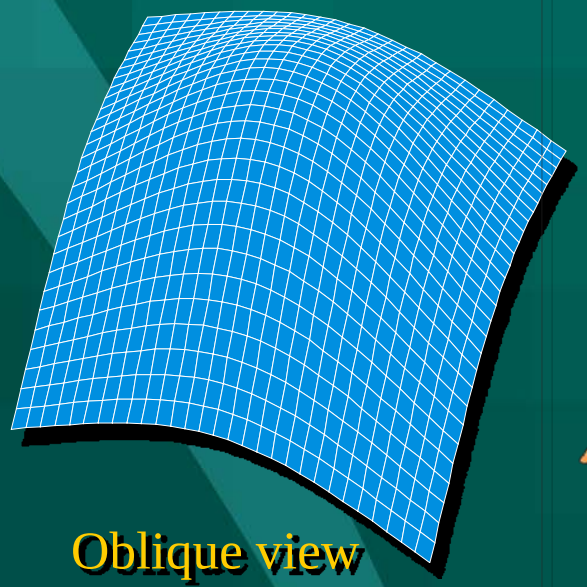
Measured Tilt – 250 nanordians

Theoretical Tilt – 250 nanordians

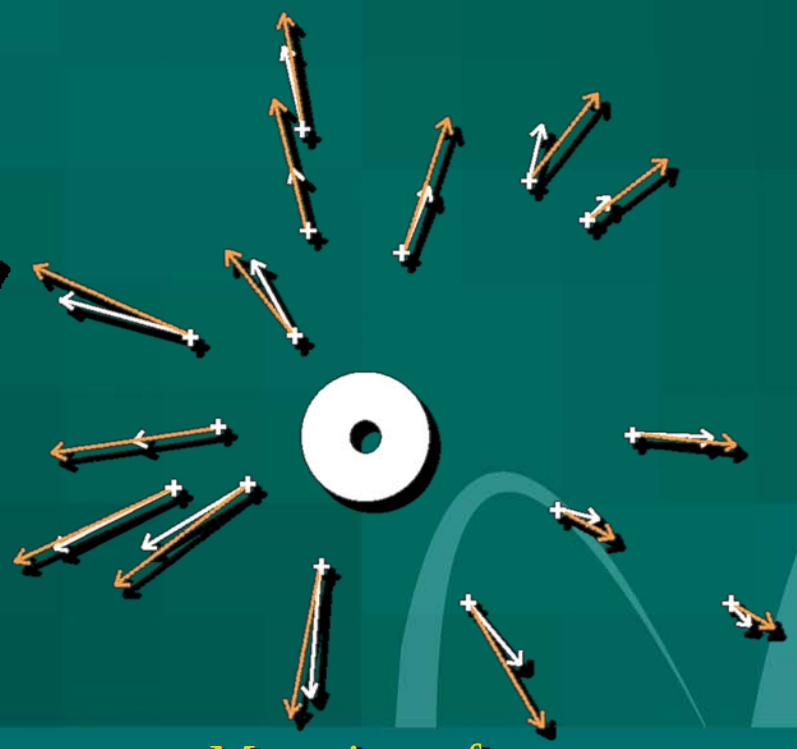
Tiltmeter Site

# Unique Vector Patterns Reflect The Unique Deformation Patterns

- Tilt vectors show “starburst” pattern characteristic of horizontal fractures.



Oblique view
of surface deformation



Map view of
tilt response

legend

1000 ft

Frac: Horizontal

Azimuth: N/A

Dip: 6°W

Depth: 2900 ft

North

Measured Tilt – 500 nanordians

Theoretical Tilt – 500 nanordians

Tiltmeter Site

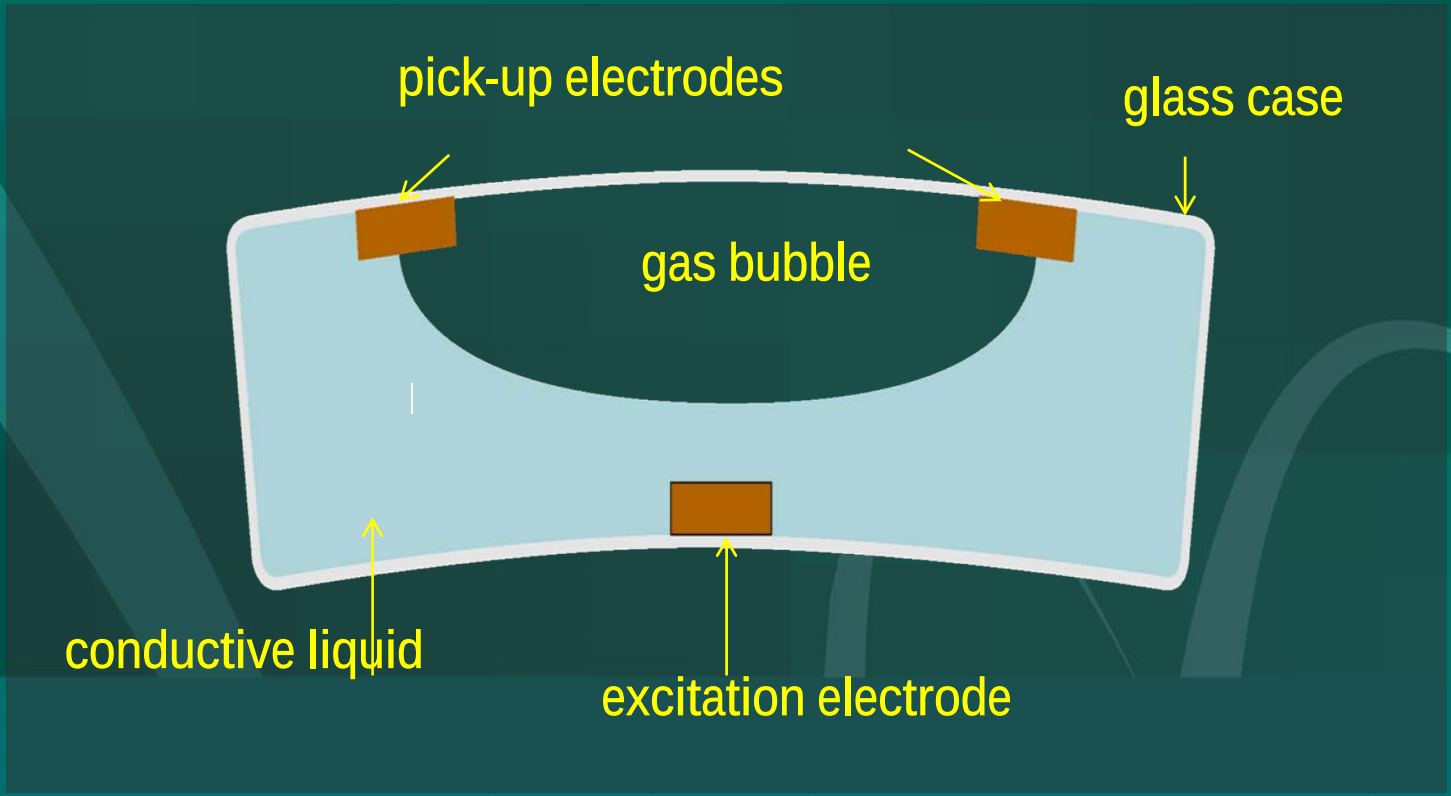
+ Wellhead

# Tiltmeters Are Essentially Deformation Gauges

Pinnacle

**Tiltmeter Contains Two Orthogonal Electronically Amplified "Carpenter's Levels" Of Extreme Precision.**

**Can Measure Tilt Down To ~1 Nano-radian (1 Billionth Of A Radian; Equivalent To Lifting One End Of A Beam Between New York And San Francisco By 1/4 Inch)**



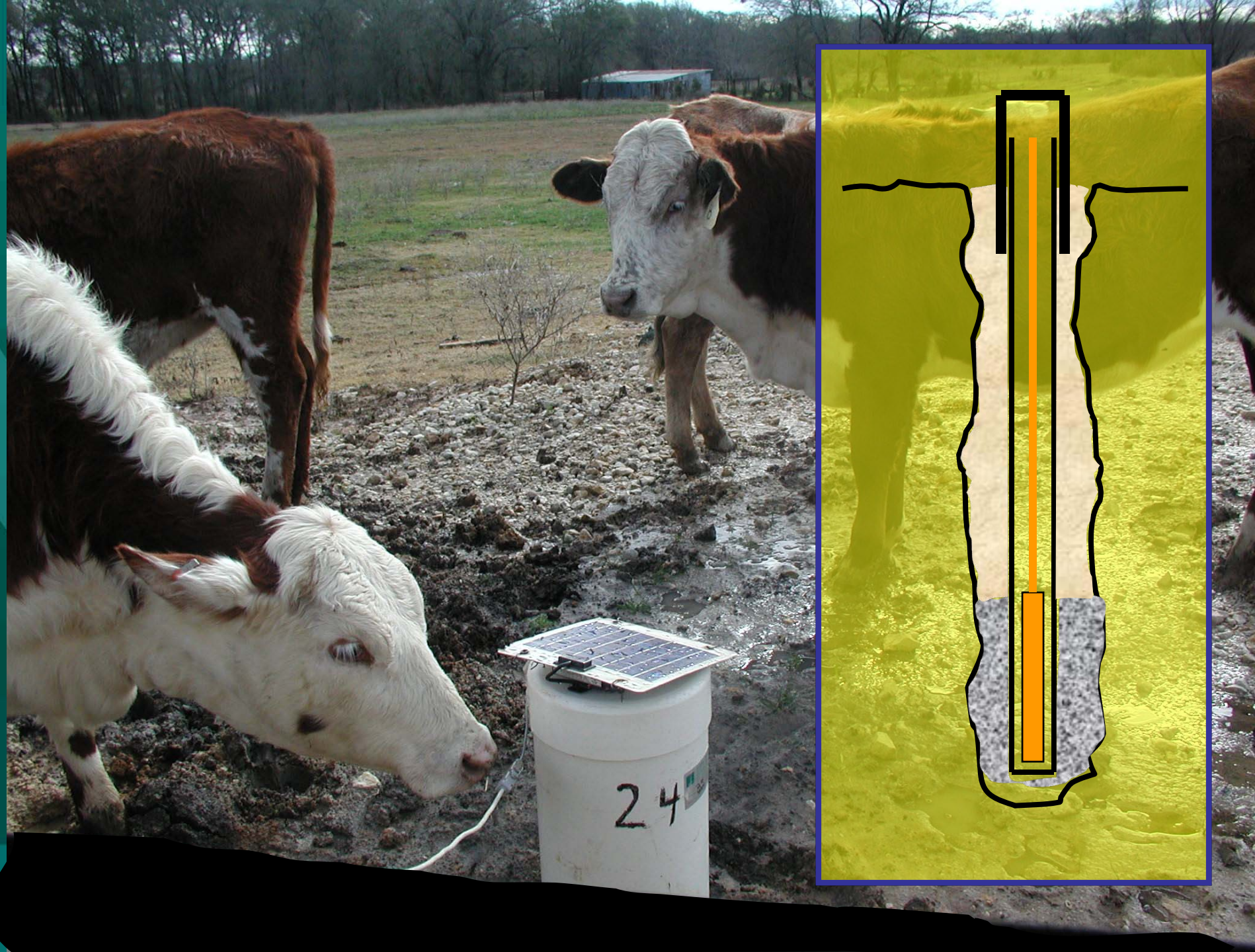
## 5500 Series Pinnacle Tiltmeter

## Automatic (Radio) Data Download Configuration

## Installation

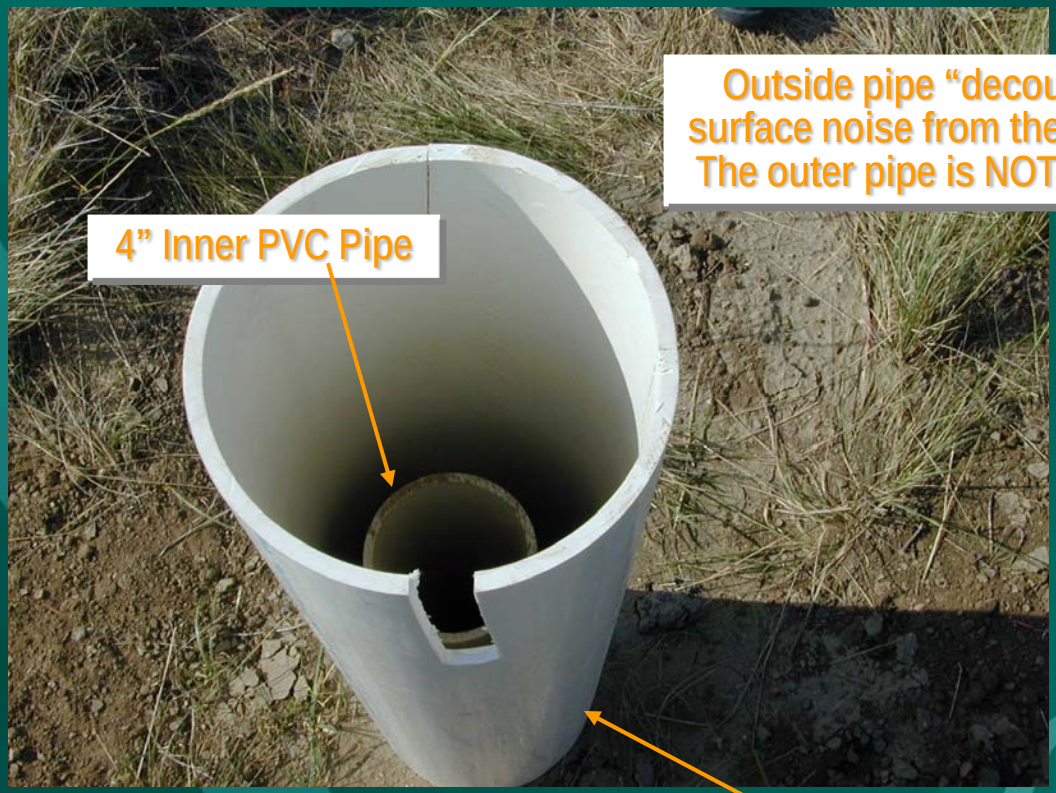
## Manual Data Download Configuration

* Pipe can be cut-off lower to ground if needed

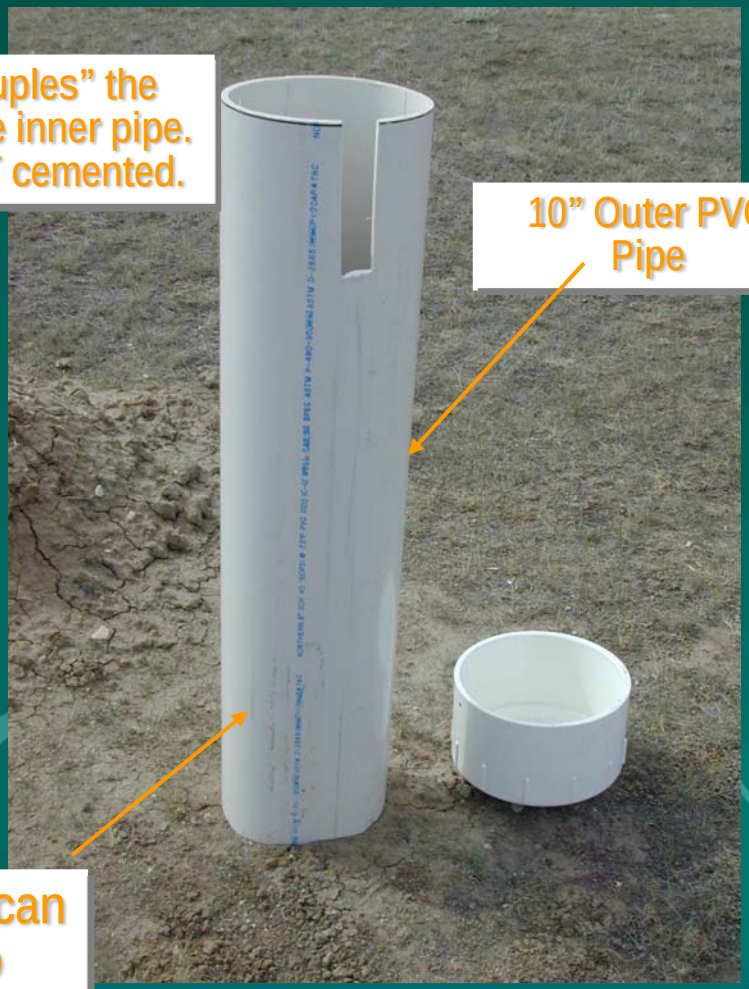

24

# Surface Tiltmeter Site

Pinnacle



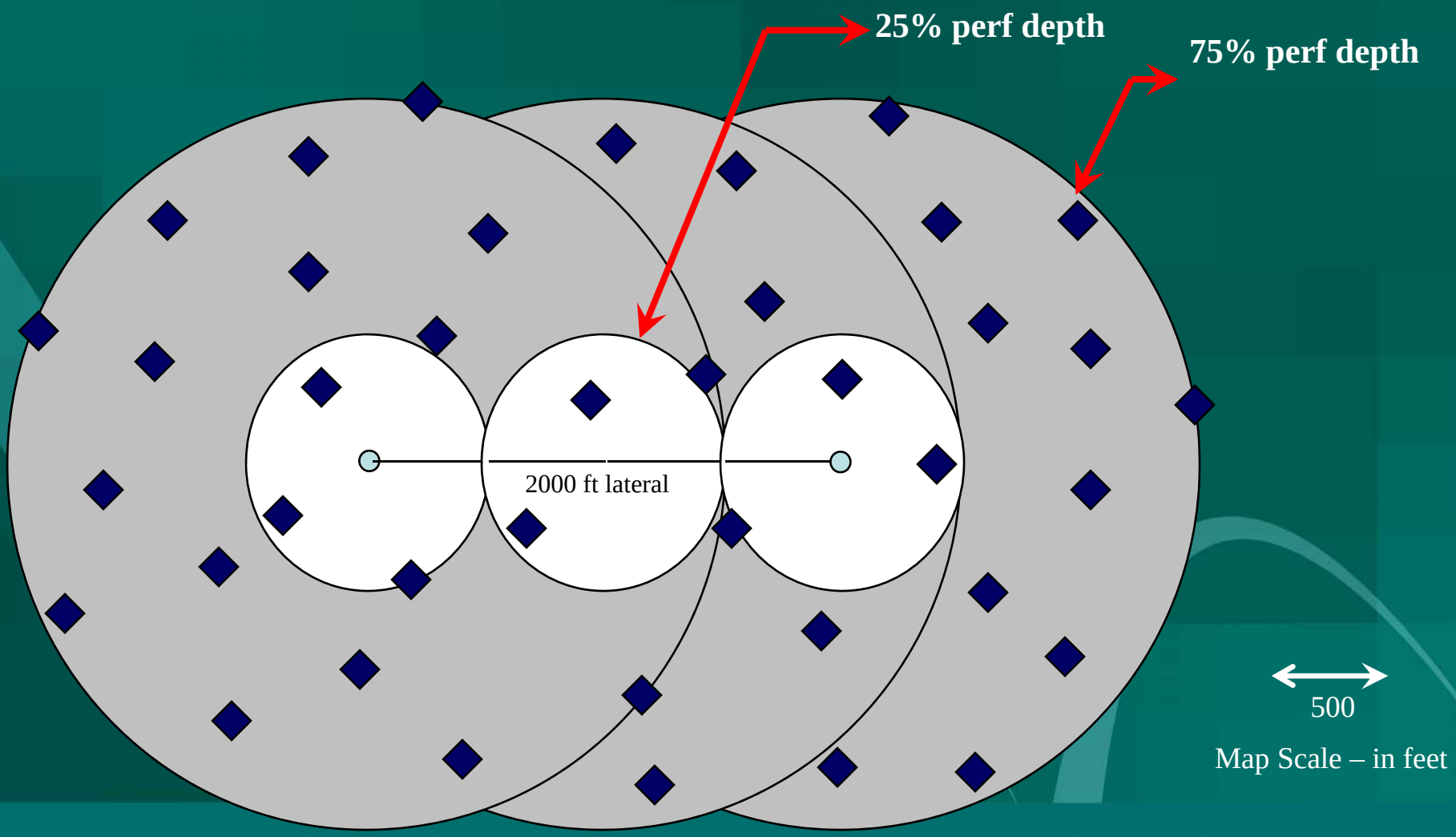

Outside pipe “decouples” the surface noise from the inner pipe. The outer pipe is NOT cemented.




Outer Pipe can be cut to desired height

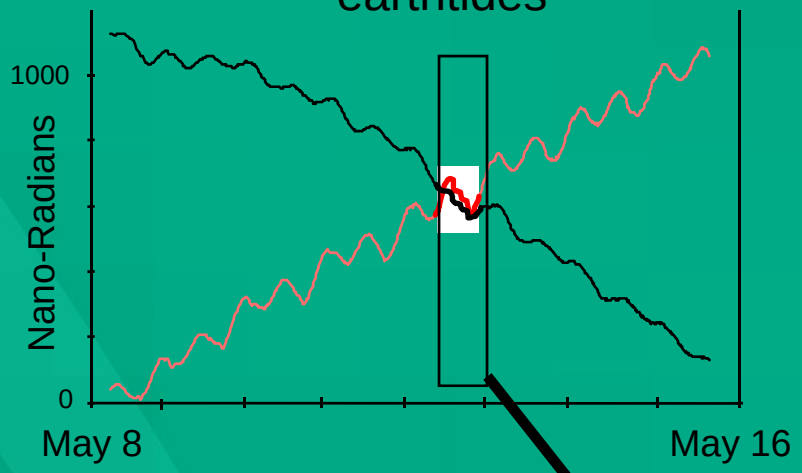
# Example of an Array for a Horizontal well

## Depth of Perfs = 2,000 ft with 2,000 ft lateral – 40 sites

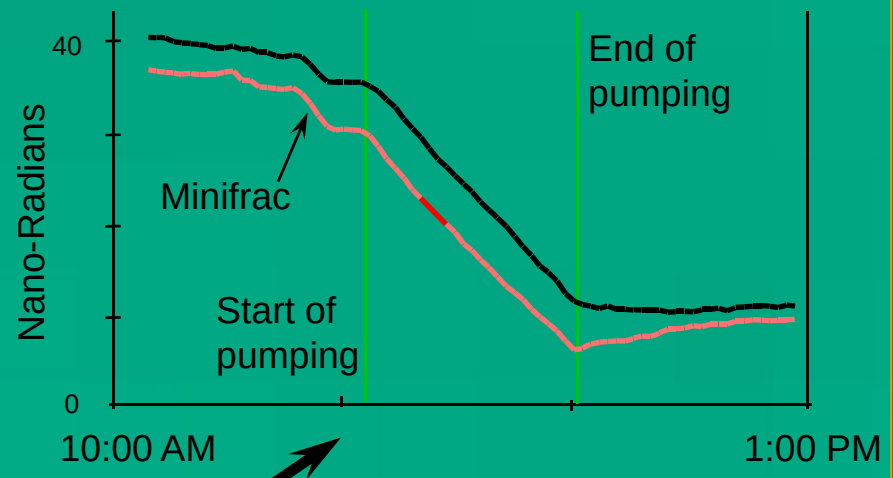


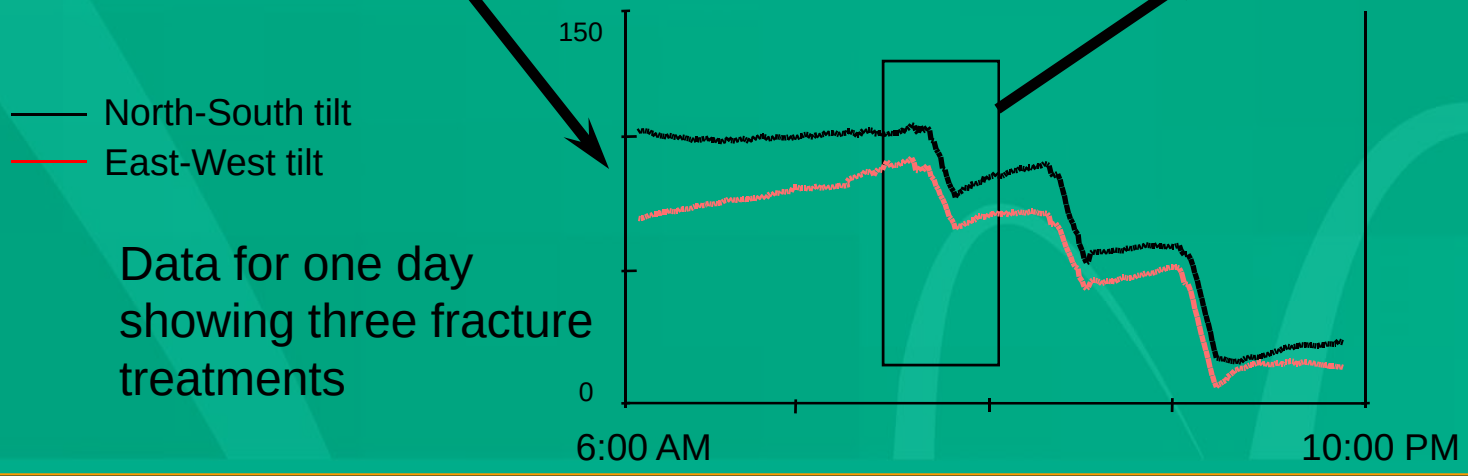
# RAW TILTMETER DATA ON 3 DIFFERENT TIME SCALES

Eight days of data showing earthtides



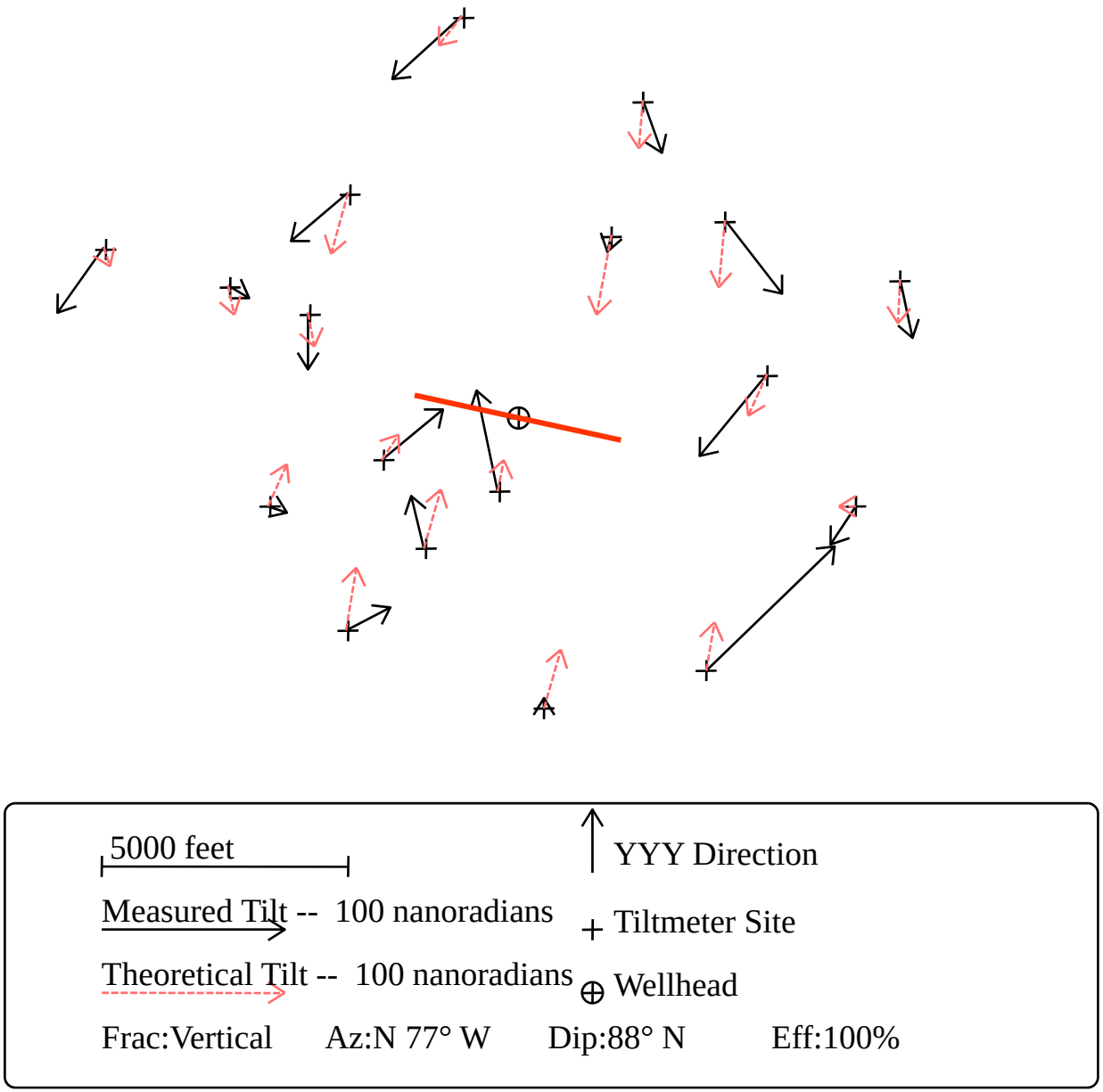

Data from one treatment



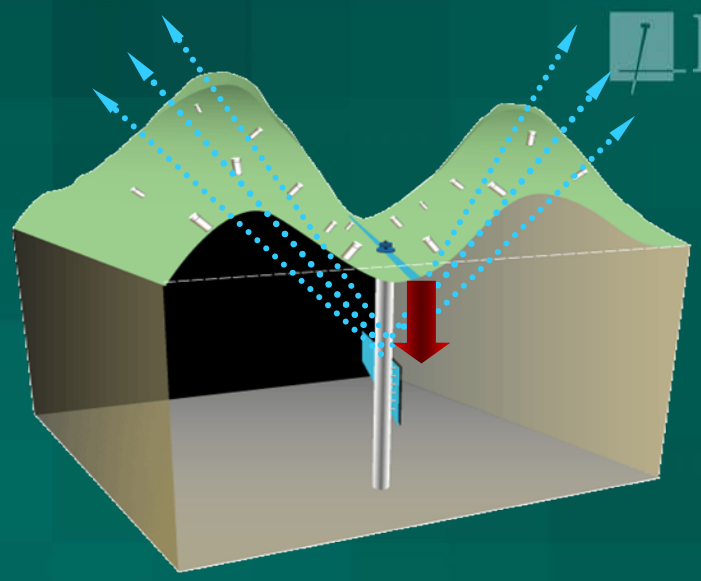

Data for one day showing three fracture treatments

# SURFACE TILT VECTORS FOR 16,000' FRAC

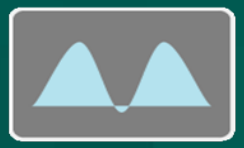


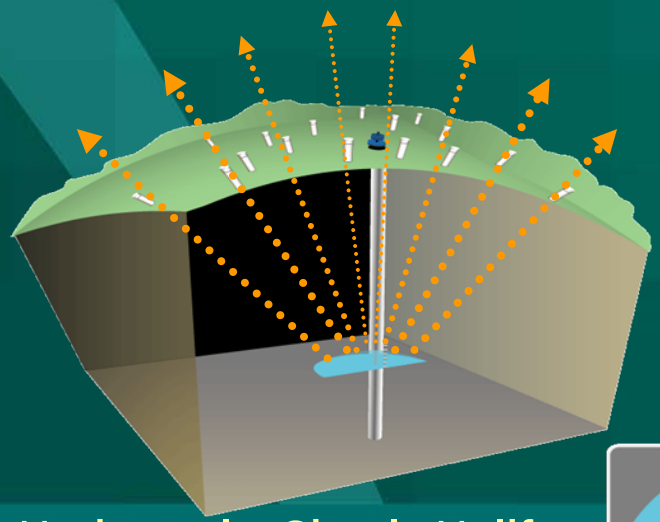
- ***Surface Tiltmeter Response***

- ***Surface Deformation From Individual Components Add Together***

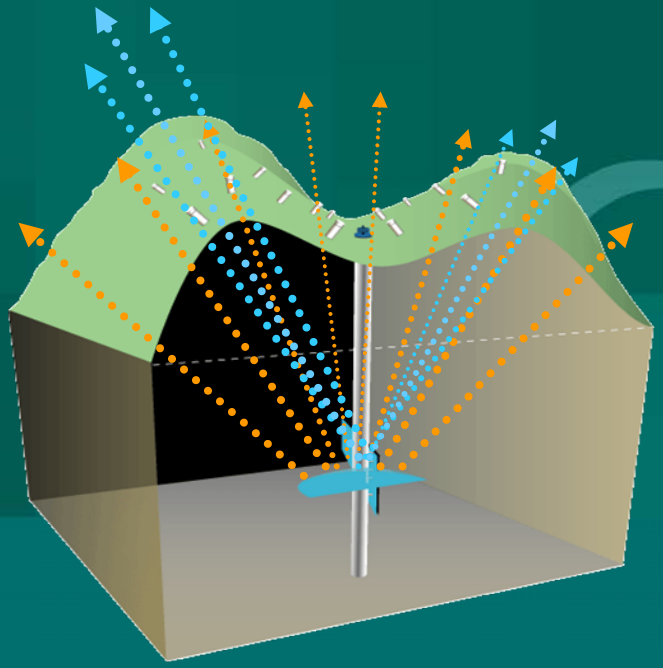


Vertical-Trough & Uplifts



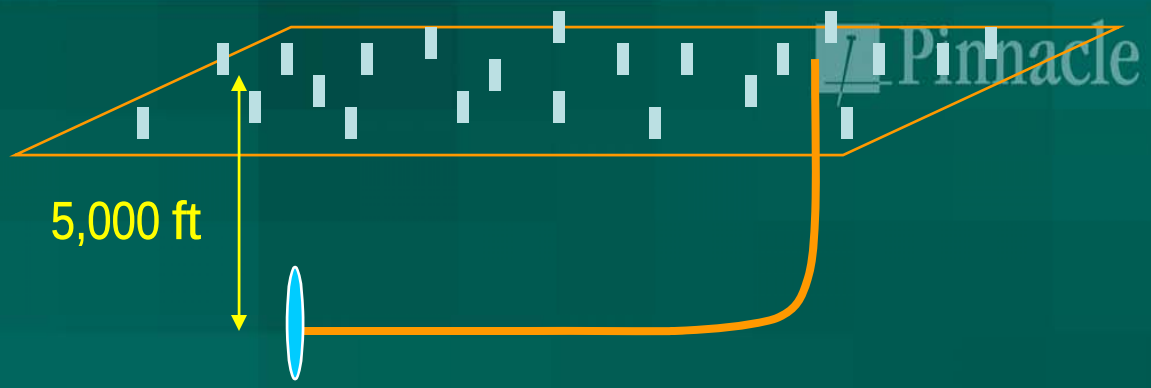


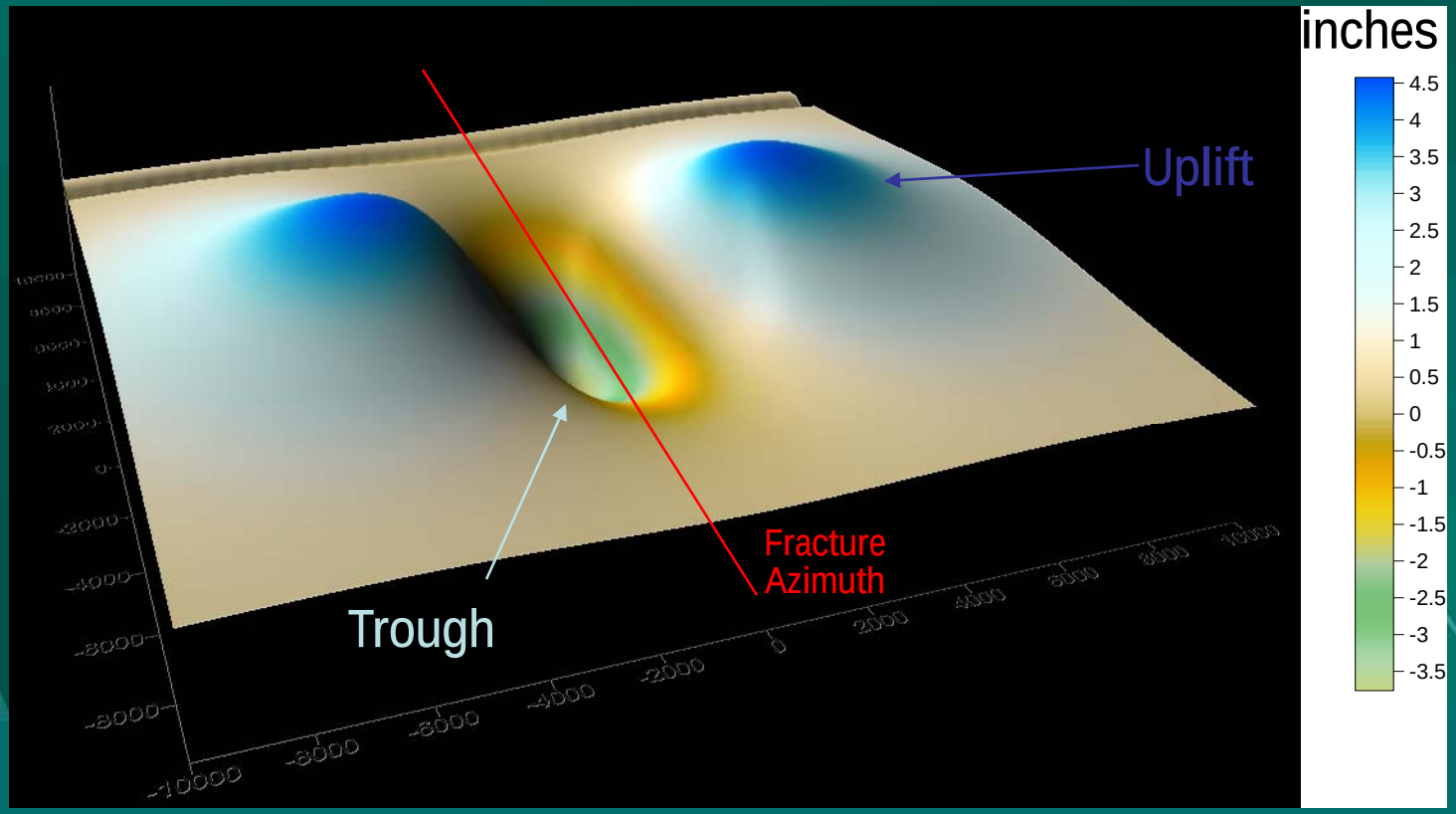
Horizontal – Simple Uplift



Combined-Trough On Top Of Uplift

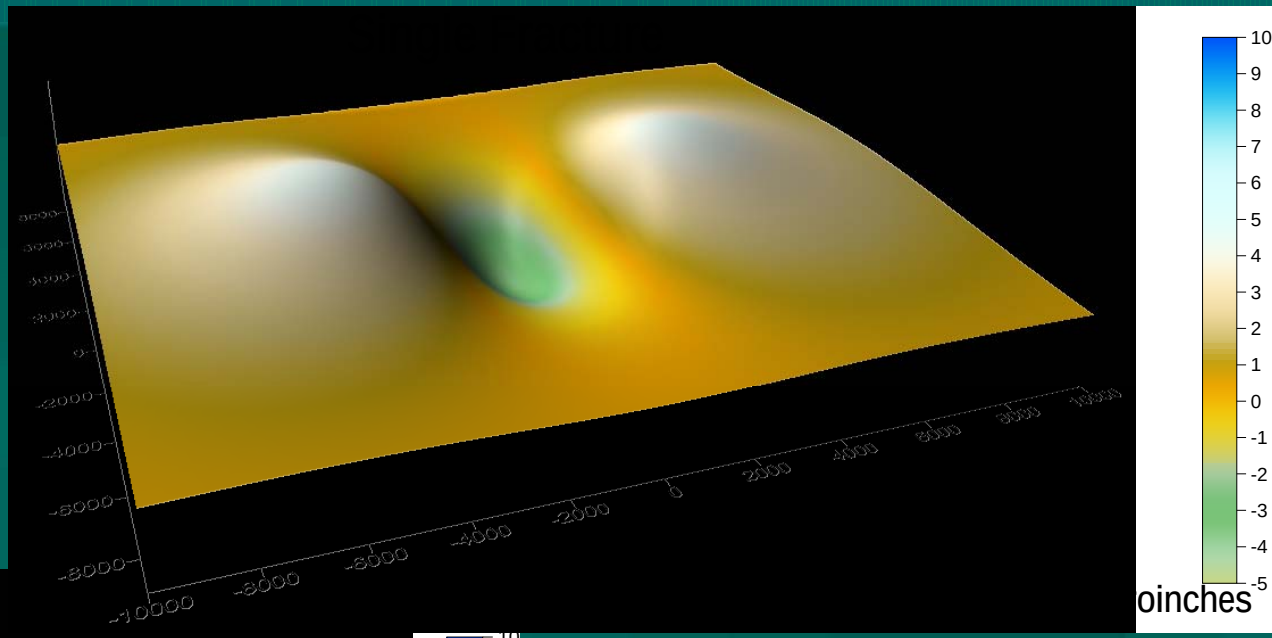
# Surface Deformation Induced By A Vertical Fracture

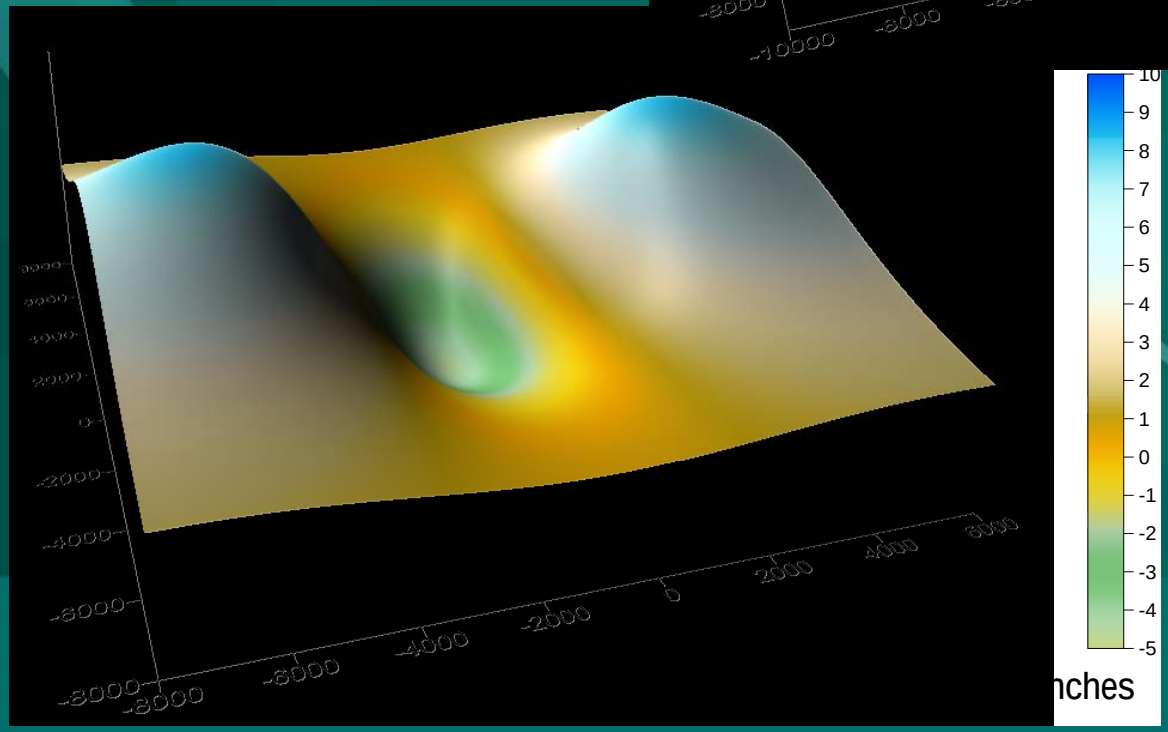


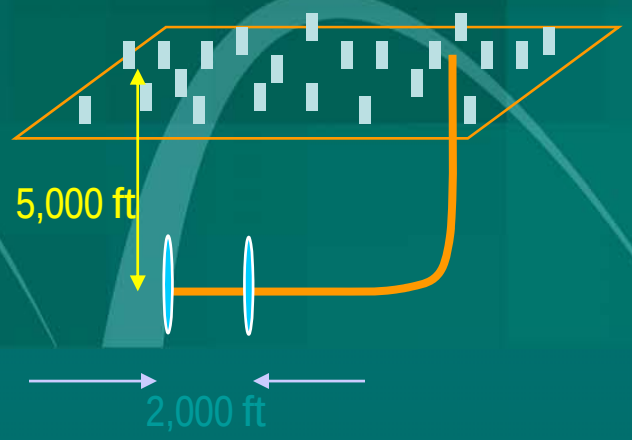
# Comparison of Surface Uplift For 1 Versus 2 Fracs

*(short spread between transverse fracs)*



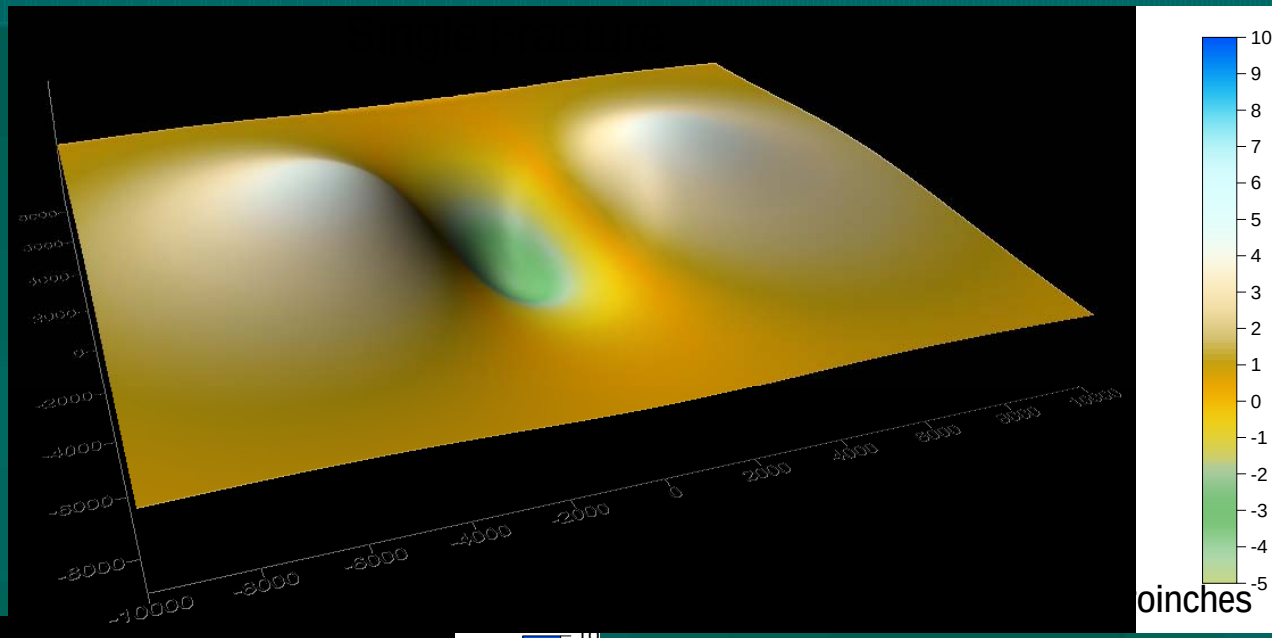



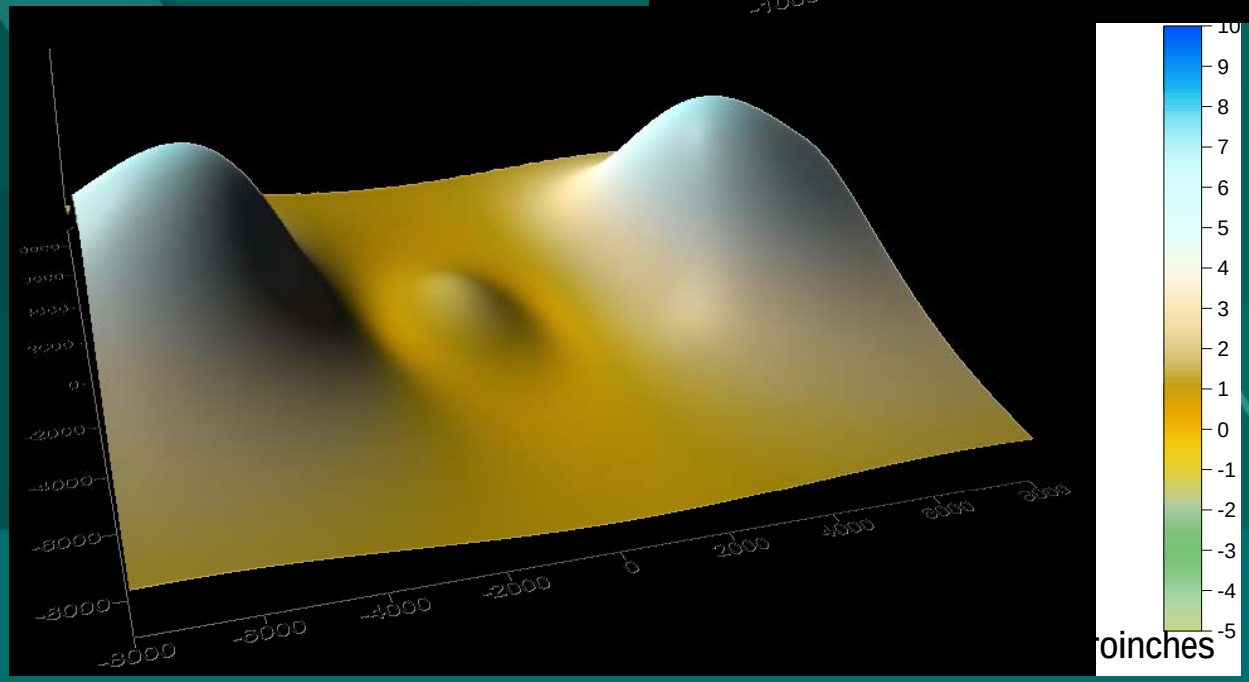

Both Examples Plotted On Same Scale



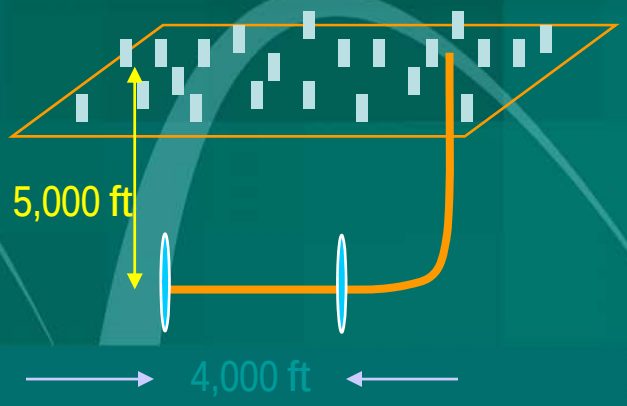
# Comparison Of Surface Uplift For 1 Versus 2 Fracs

*(longer spread between transverse fracs)*



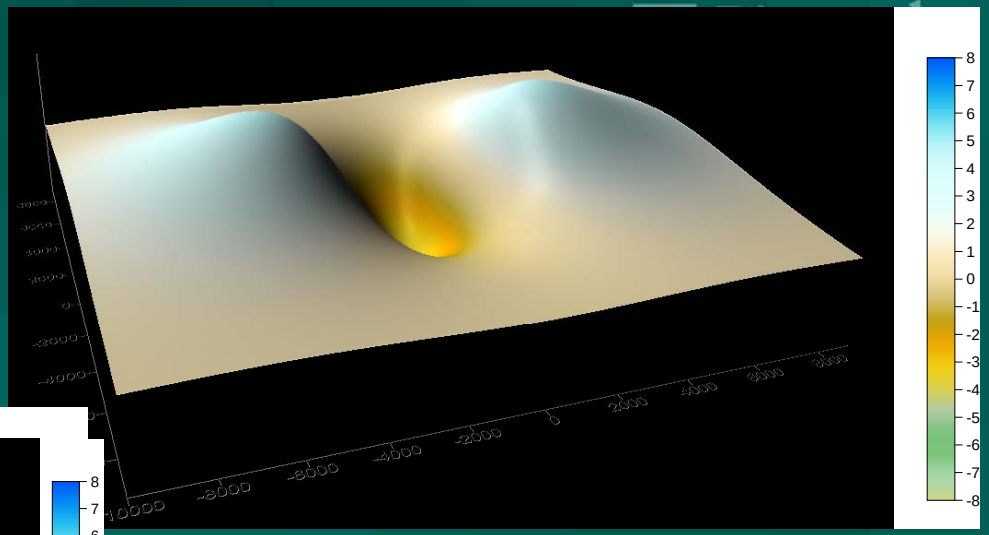



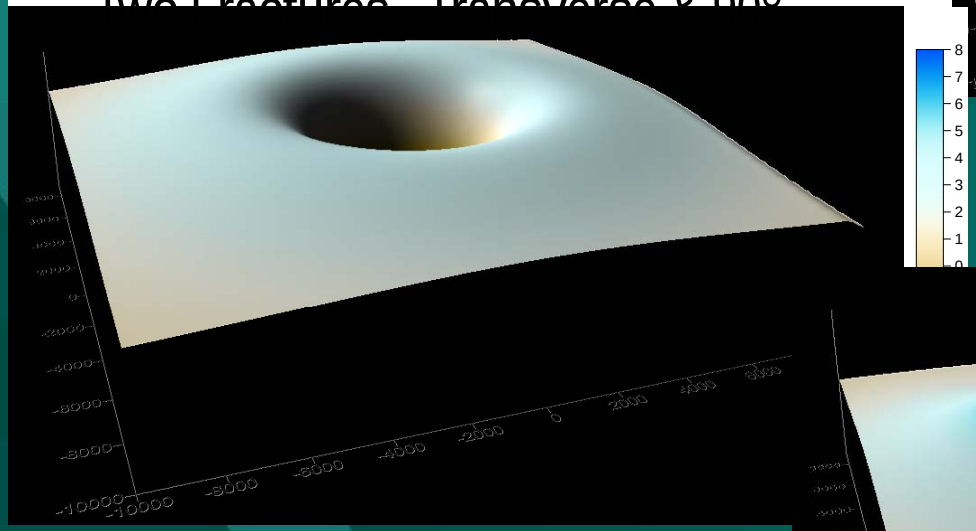

Both Examples Plotted On Same Scale

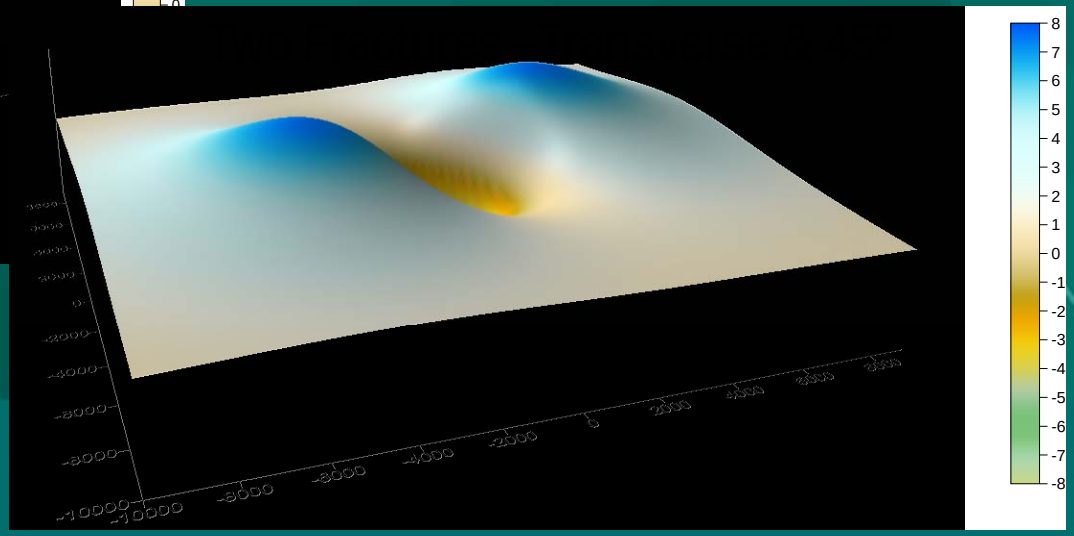


# Comparison Of Different Vertical Components

- Significant Change In Surface Deformation With Addition Of Other Fracture Planes
  - Equal Size Fractures In Both Planes




*All Data Plotted At Same Scale*

Pinnacle

# Fracture Mapping Results

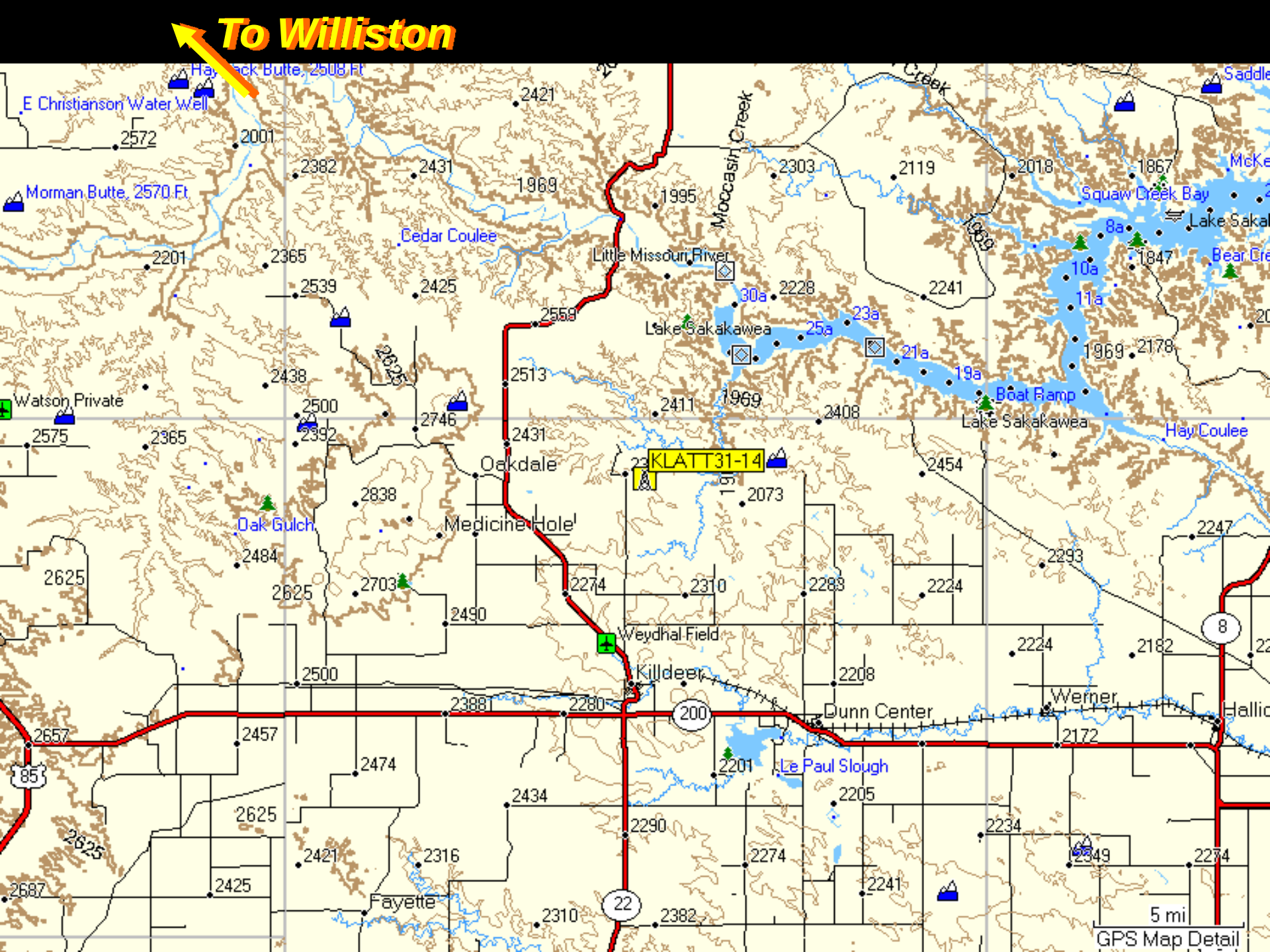
## Klatt 31-14H – First stimulation attempt ("Stage 1")

**July 23, 2007**

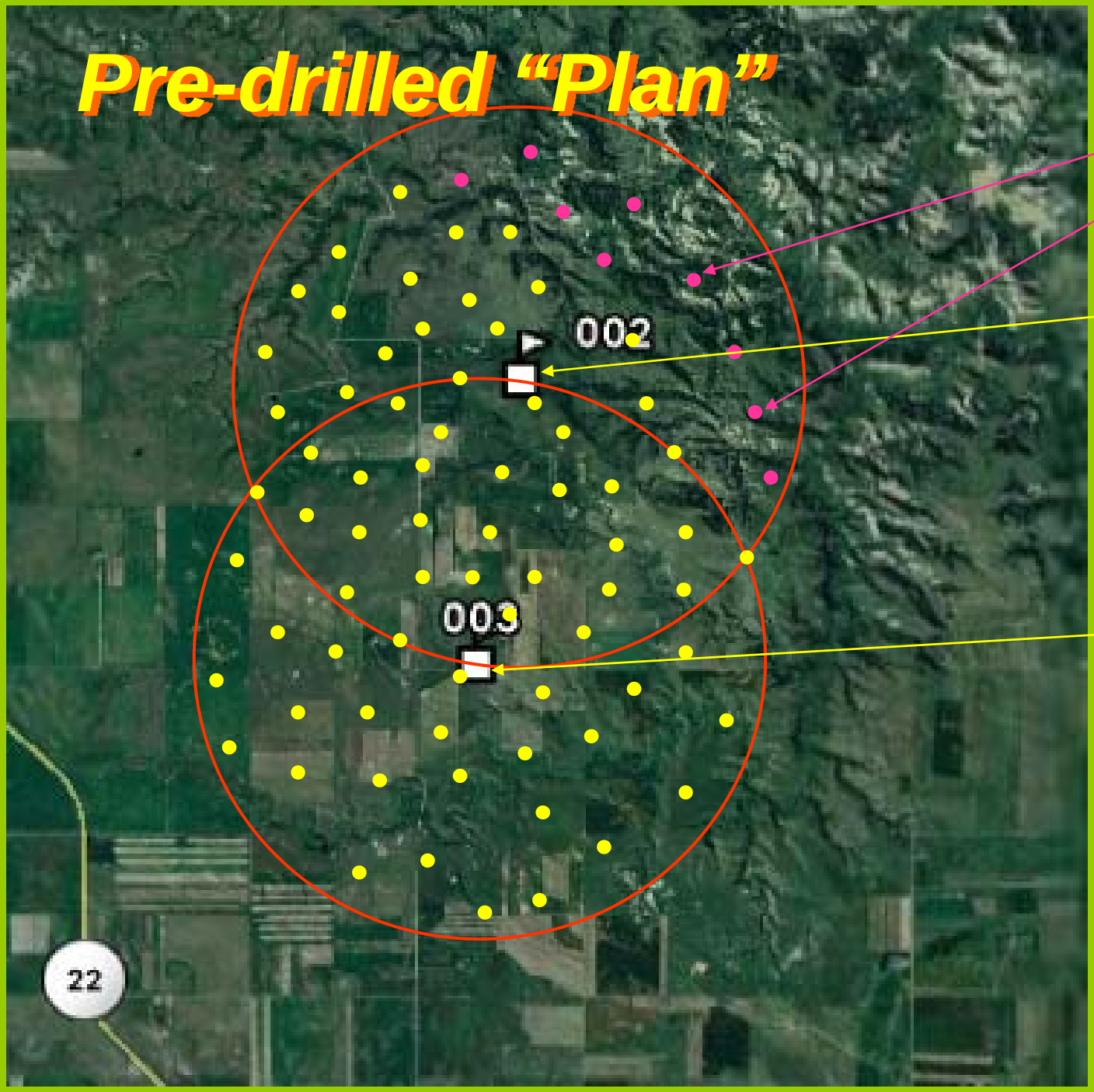
# Marathon Oil Company
# Dunn Co., North Dakota

# Objectives

- Monitor aborted fracture treatment performed on July 23, 2007.
- Measure volume distribution along the lateral section
- Measure dominate fracture azimuth if fluid distribution along WB is not even


To Williston
E Christianson Water Well
Morman Butte, 2570 Ft
Cedar Coulee
Little Missouri River
Moccasin Creek
Lake Sakakawea
Squaw Creek Bay
Boat Ramp
Hay Coulee
Watson Private
Oakdale
KLATT31-14
Oak Gulch
Medicine Hole
Weydhal Field
Killdeer
Dunn Center
Werner
Le Paul Slough
Fayette
5 mi
GPS Map Detail

# Pre-drilled "Plan"




**Might not be able to drill some sites here due to terrain conditions**

Original planned Surface Location

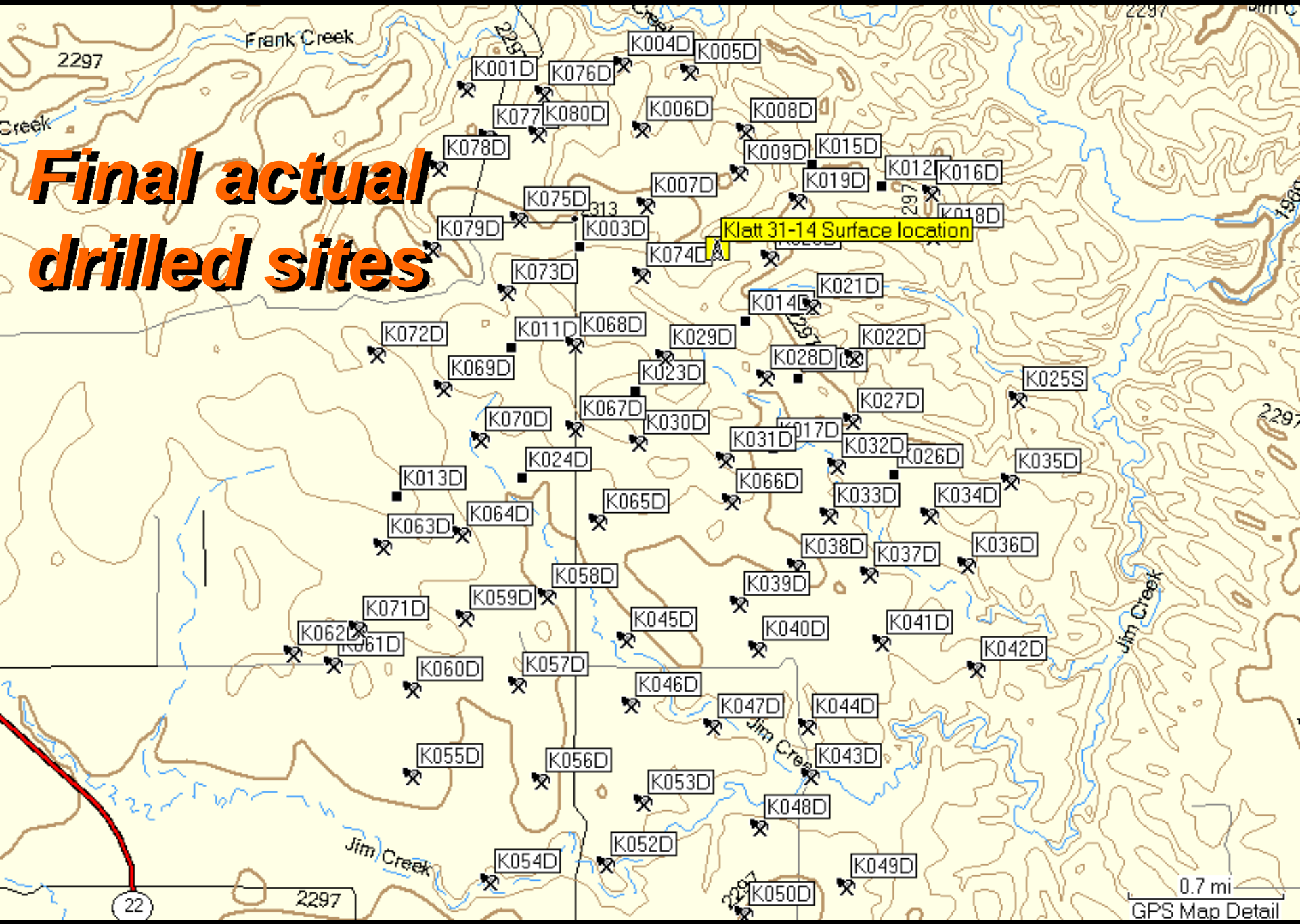
Original planned Downhole Location

80 planned surface tiltmeter locations

Most density on the lateral area

Locations to the NE can be moved to accommodate terrain conditions

# Final actual drilled sites

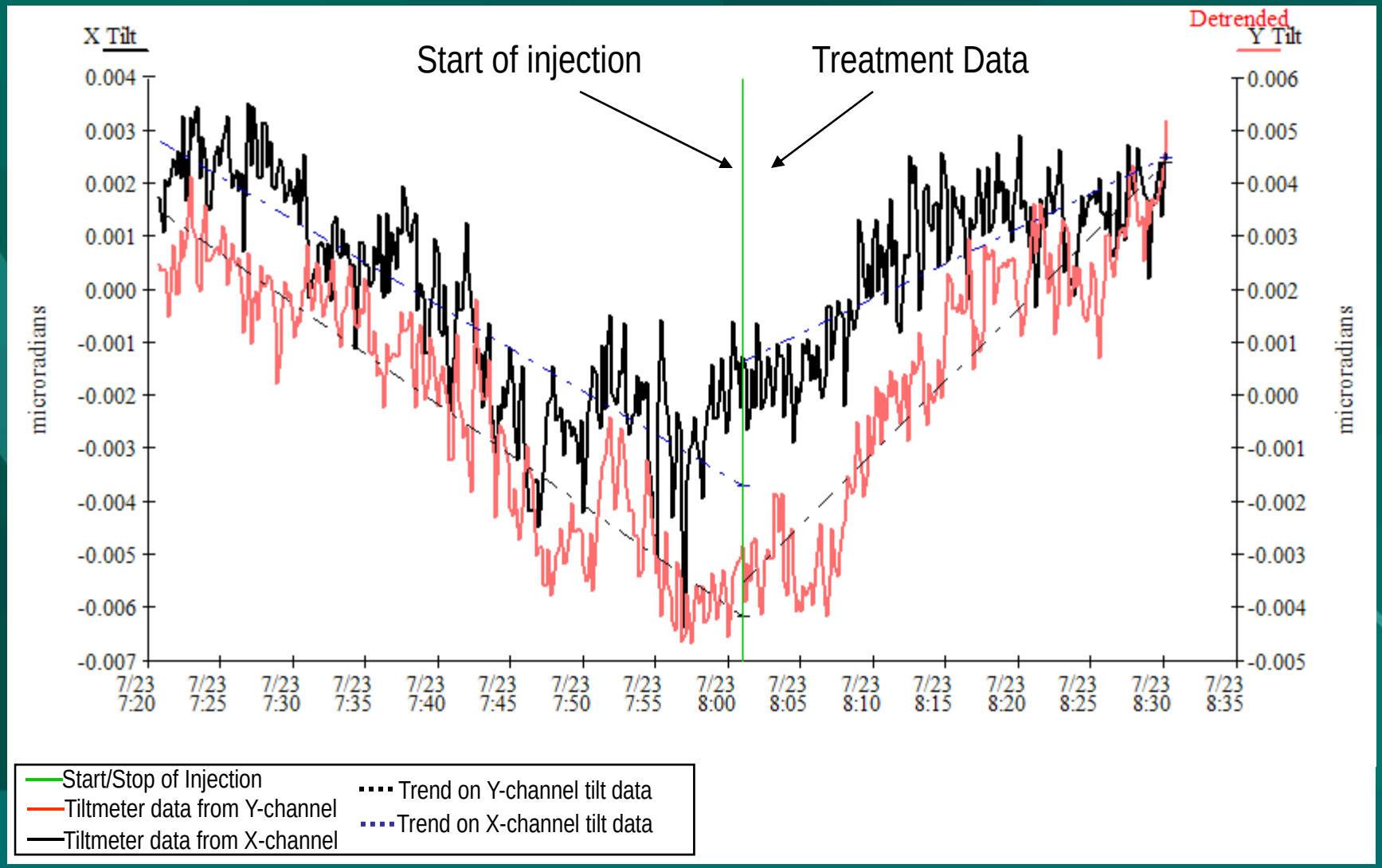


# So, What did we find?

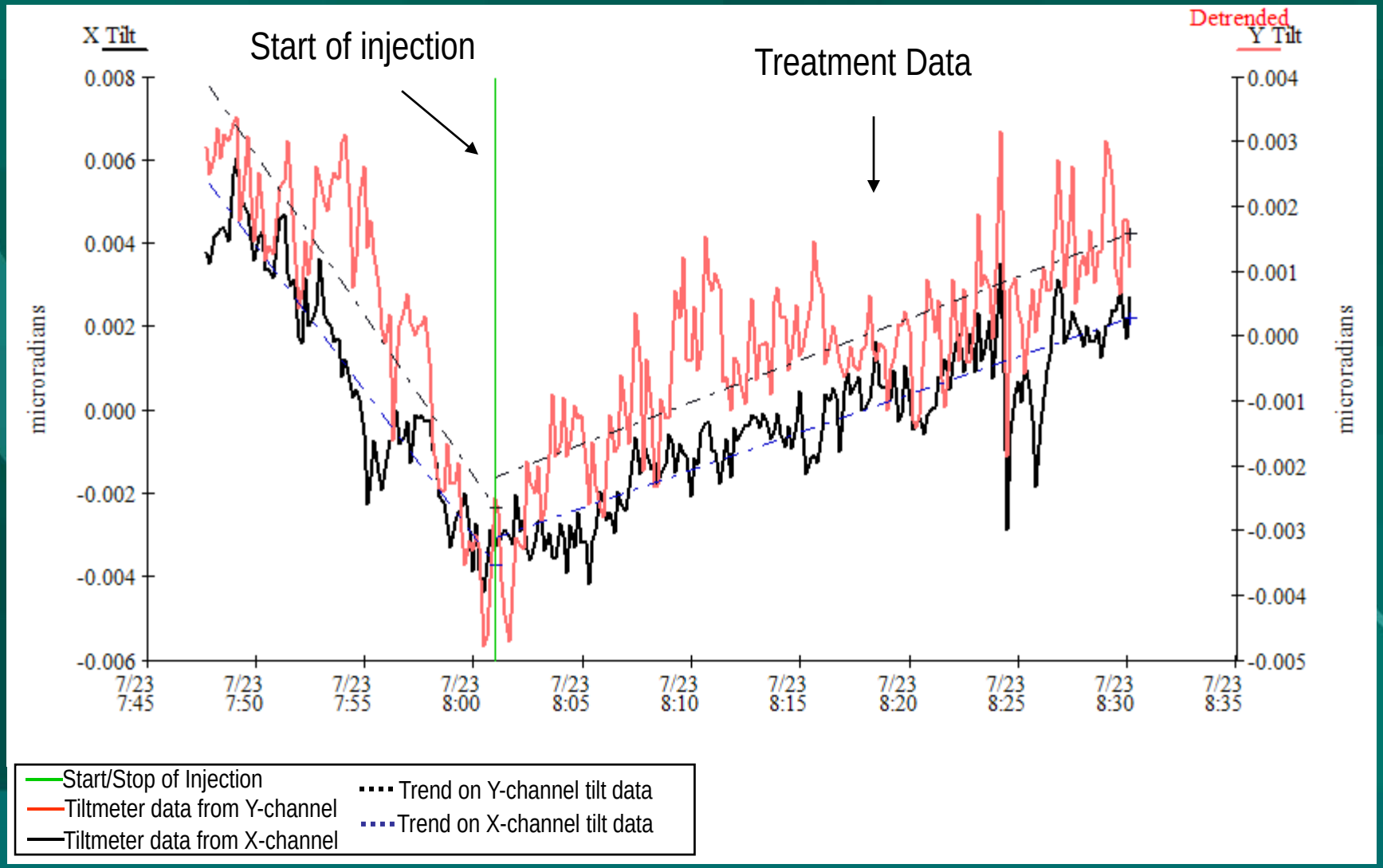
- 1st 40 minutes of frac: Unequal distribution along lateral
  - Heel: 20%
  - Middle: 40%
  - Toe: 40%

Final measurement: Unequal distribution along lateral
  - Heel: 10%
  - Middle: 40%
  - Toe: 50%

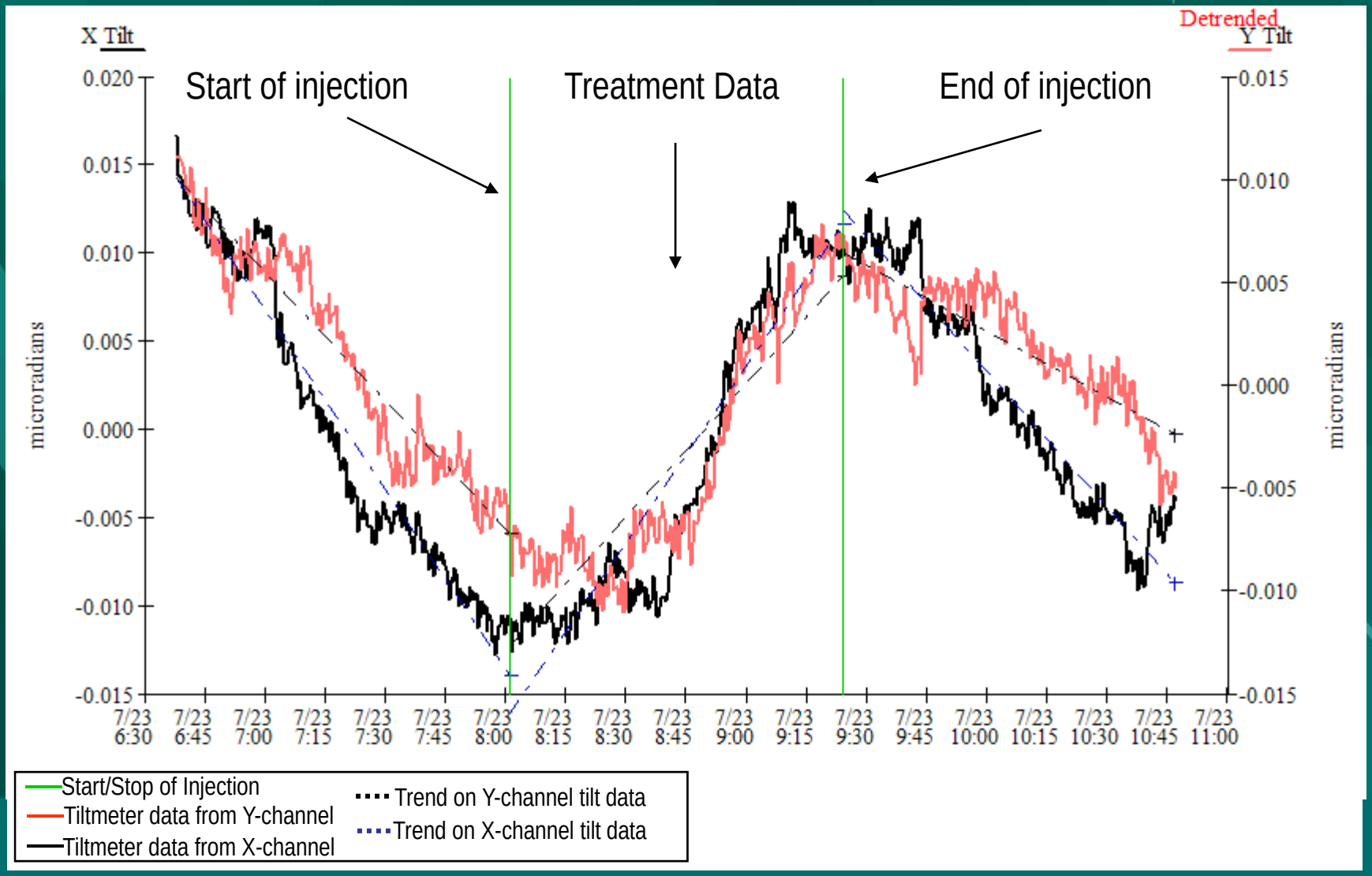
# Example of Tilt Data from Well Klatt 31-14H (site K016)



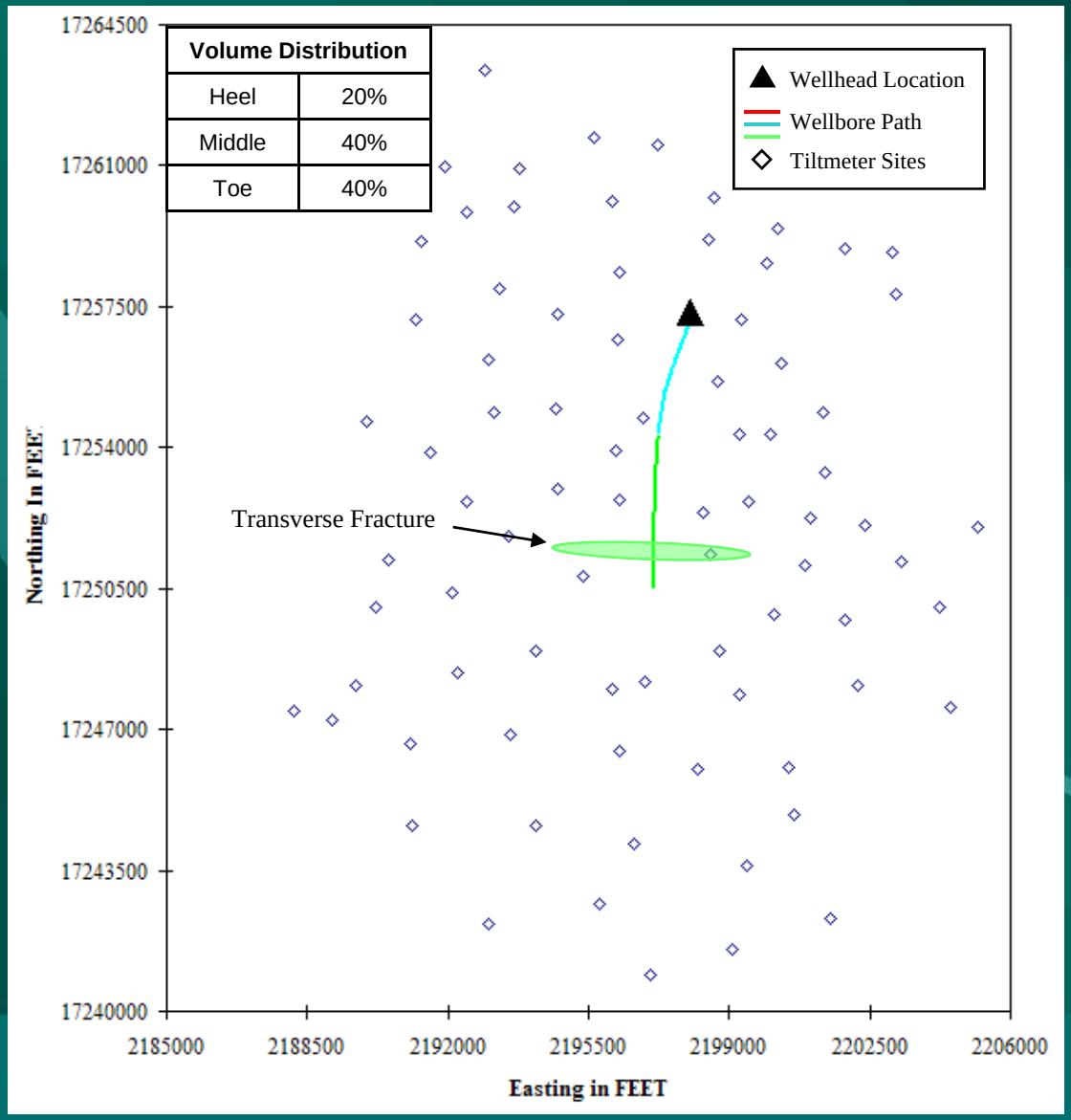
# Example of Tilt Data from Well Klatt 31-14H (site K031)



# Example of Tilt Data from Well Klatt 31-14H (site K036)



# Plan View Showing Vertical Fractures w/ Array Layout




## First 40 Minutes (Stage 1)

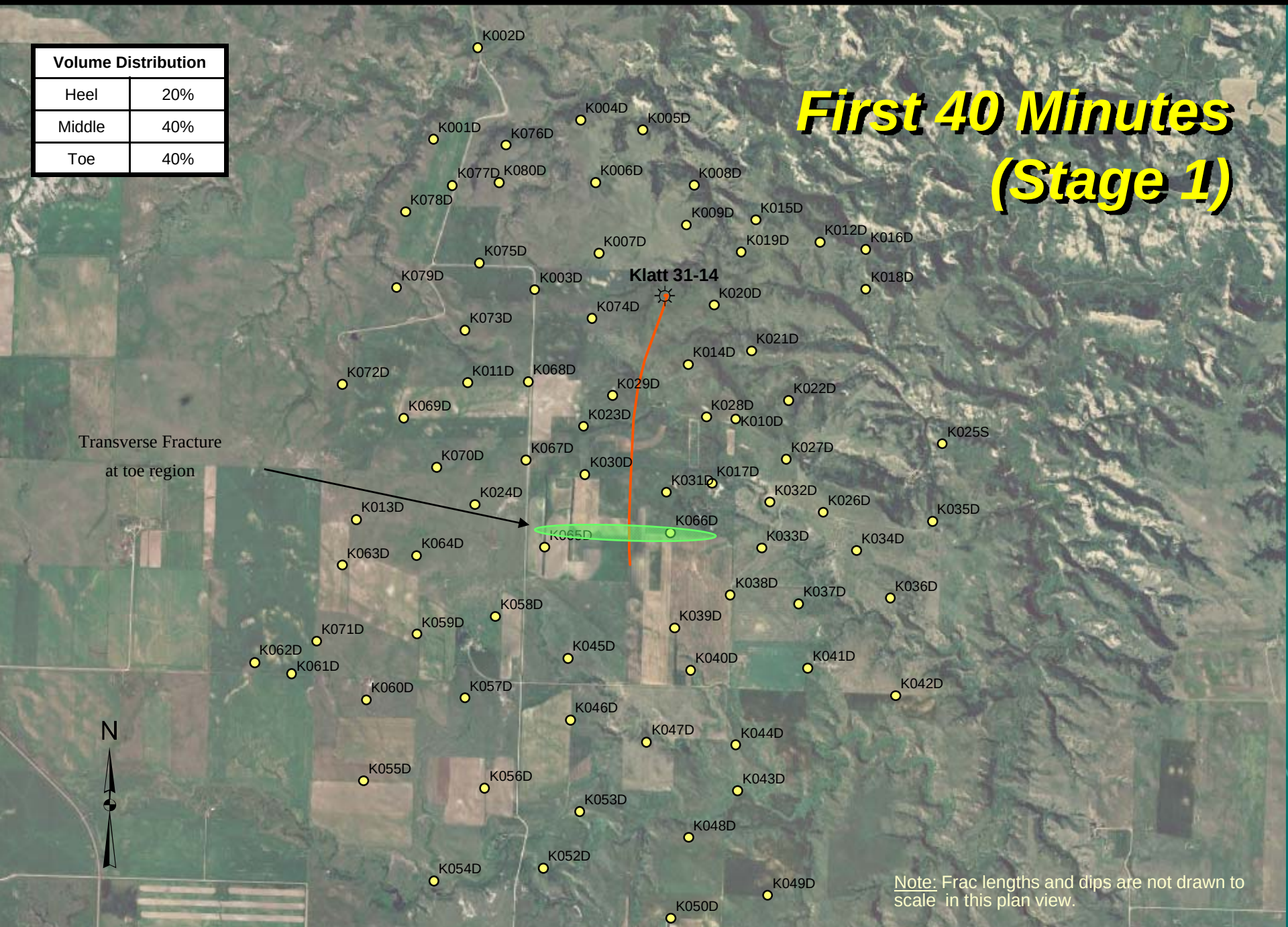
- Green ellipse represents the general trend of the transverse vertical fracture and its approximate location at the toe region.

- Fracture volume distribution
  - Heel: 20%
  - Middle: 40%
  - Toe: 40%

Note: Fracture dips and lengths are not properly represented in this plan view.

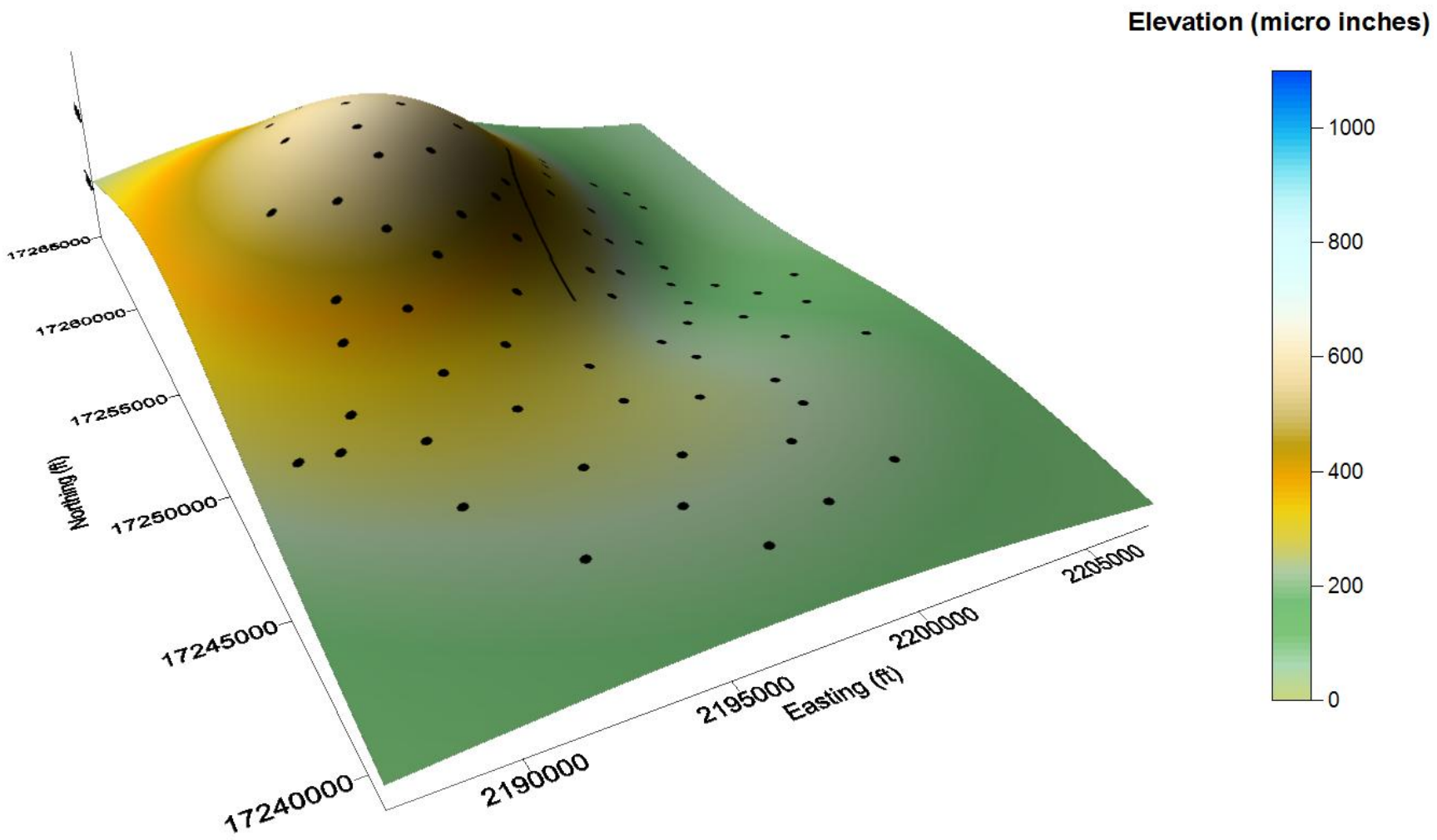
# First 40 Minutes (Stage 1)

| Volume Distribution | |
|---|---|
| Heel | 20% |
| Middle | 40% |
| Toe | 40% |




Note: Frac lengths and dips are not drawn to scale in this plan view.

# First 40 Minutes (Stage 1)




**Best-fit theoretical deformation visualization**

# Summary of Tilt Mapping Results for Well Klatt 31-14H
## (After full treatment)

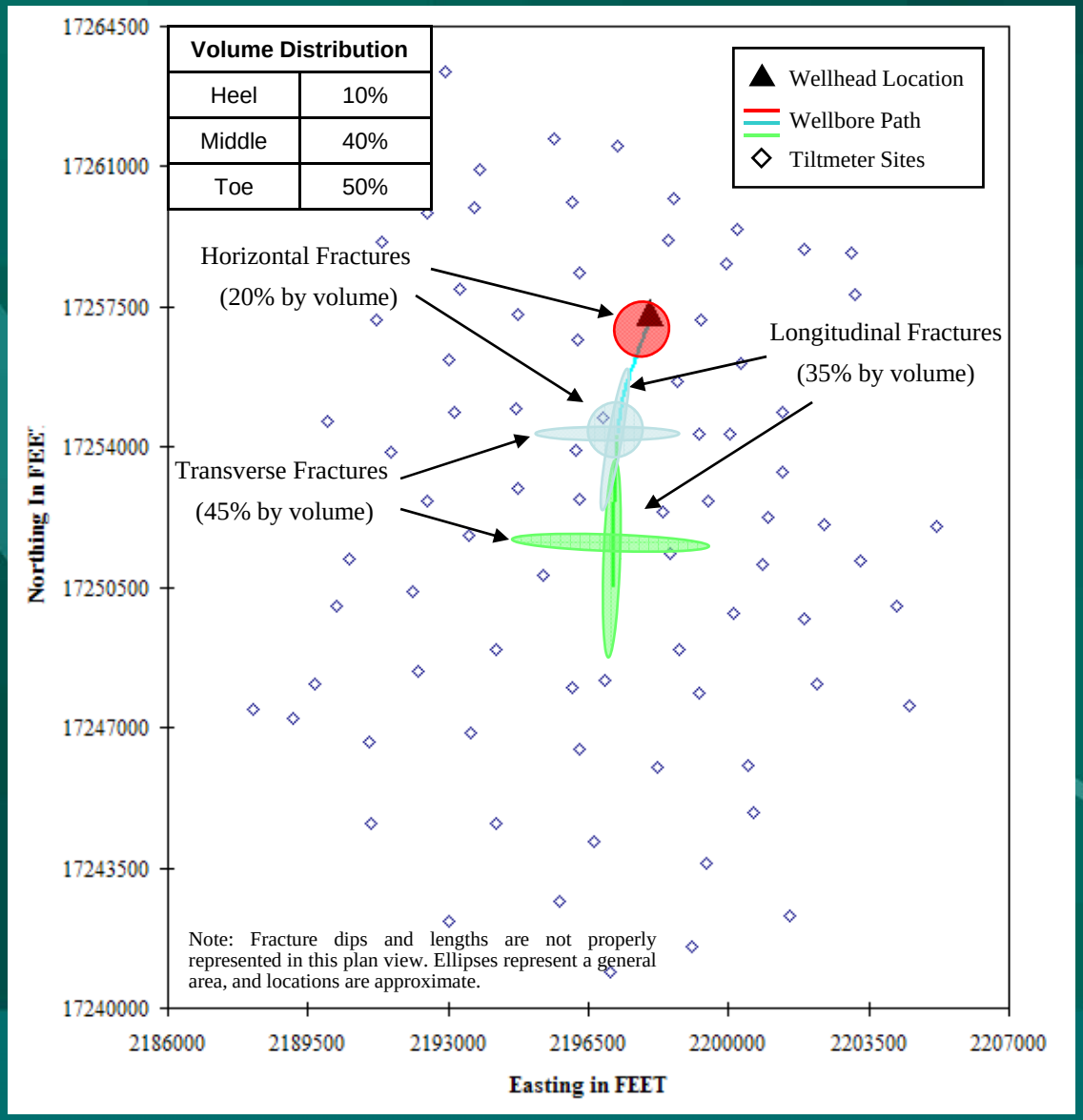
Pinnacle

| Stage | Job Date | Injection Times (Local) (Volume) | Perfs. Depth TVD (ft) | Volume Percentage | | |
|---|---|---|---|---|---|---|
| | | | | **Heel** | **Middle** | **Toe** |
| **1** | **07/23/07** | **8:01 – 9:24 (3,892 bbls)** | **10,858** | **~10% horizontal** | **15% - Transverse**<br>**15% - Longitudinal**<br>**~10% horizontal** | **30% - Transverse**<br>**20% - Longitudinal** |
| **Totals** | | | | **10%** | **40%** | **50%** |

**45% Transverse 35% Longitudinal 20% Horizontal**

** (Times are Mountain Time)*

# Plan View (After full treatment, Stage 1)

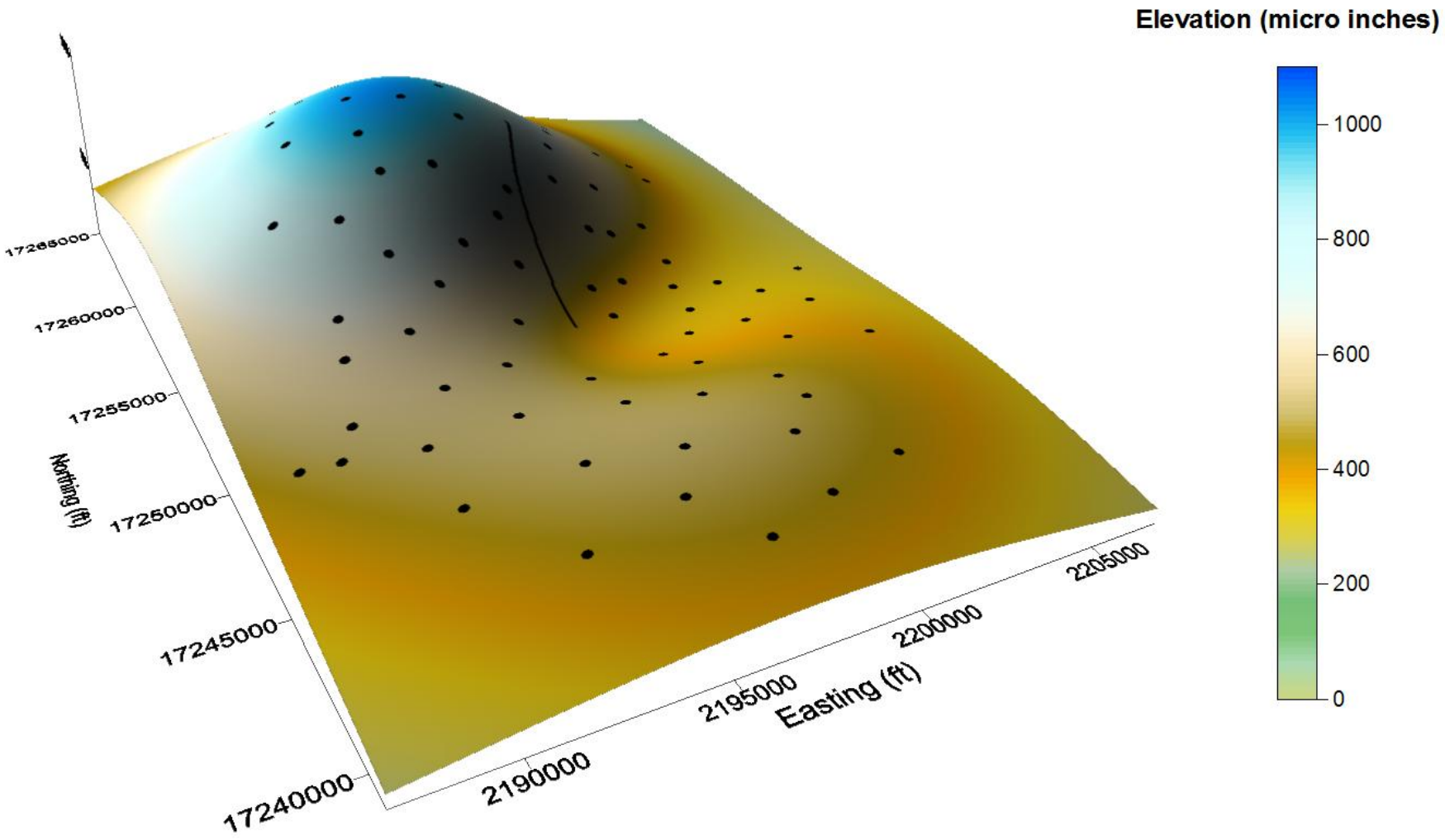



Colored ellipses represent the general trend of the vertical fracture(s), and their approximate location; circles are horizontal components.

Fracture volume distribution was mapped, and the results were divided according to the area as follows:

- Green Ellipse(s): 50% of the volume pumped – Toe of the lateral section
- Blue Ellipse(s): 40% of the volume pumped – Middle of the lateral section
- Red Ellipse(s): 10% of the volume pumped – Heel of the lateral section

# Best-fit theoretical deformation visualization after full treatment

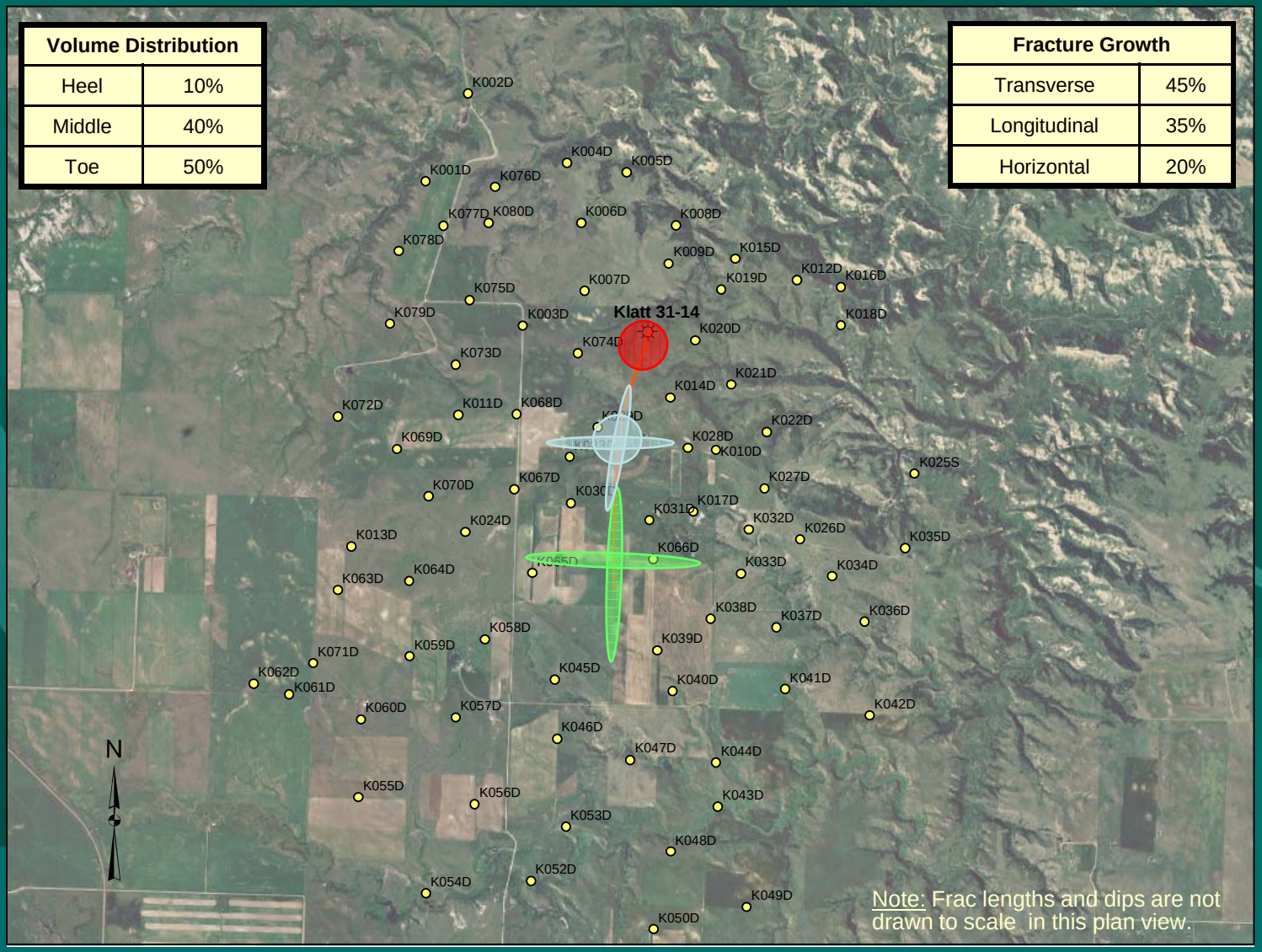


# Plan View (After full treatment, Stage 1)

Pinnacle

| Volume Distribution | |
|---|---|
| Heel | 10% |
| Middle | 40% |
| Toe | 50% |

| Fracture Growth | |
|---|---|
| Transverse | 45% |
| Longitudinal | 35% |
| Horizontal | 20% |




Note: Frac lengths and dips are not drawn to scale in this plan view.

Pinnacle

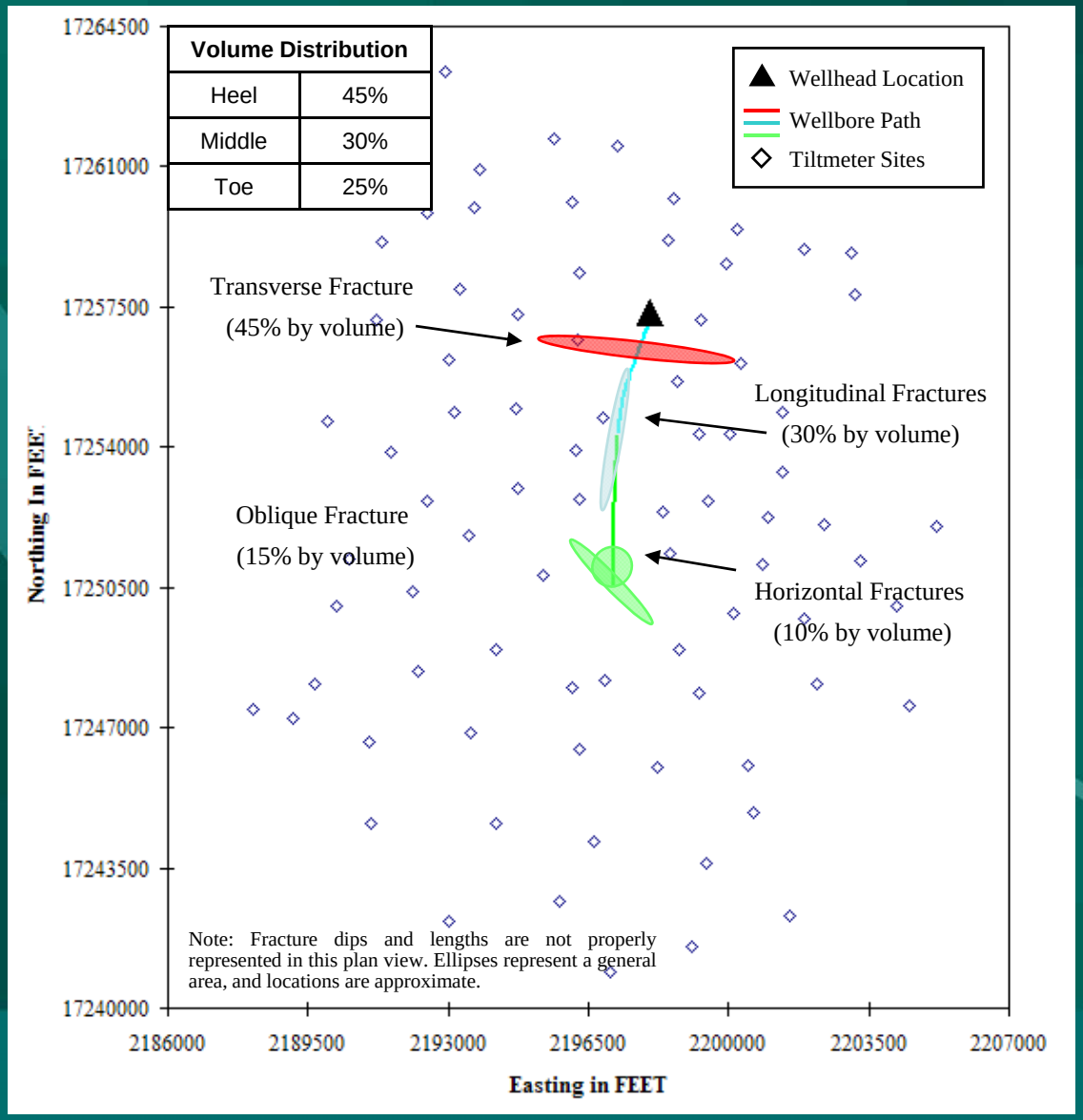
# Fracture Mapping Results

## Klatt 31-14H – Second stimulation attempt ("Stage 2")

**September 5, 2007**

# Marathon Oil Company
# Dunn Co., North Dakota

# Plan View w/ Array Layout - 9/5/2007 Injection (Stage 2)




Colored ellipses represent the general trend of the vertical fracture(s), and their approximate location; circles are horizontal components.

Fracture volume distribution was mapped, and the results were divided according to the area as follows:

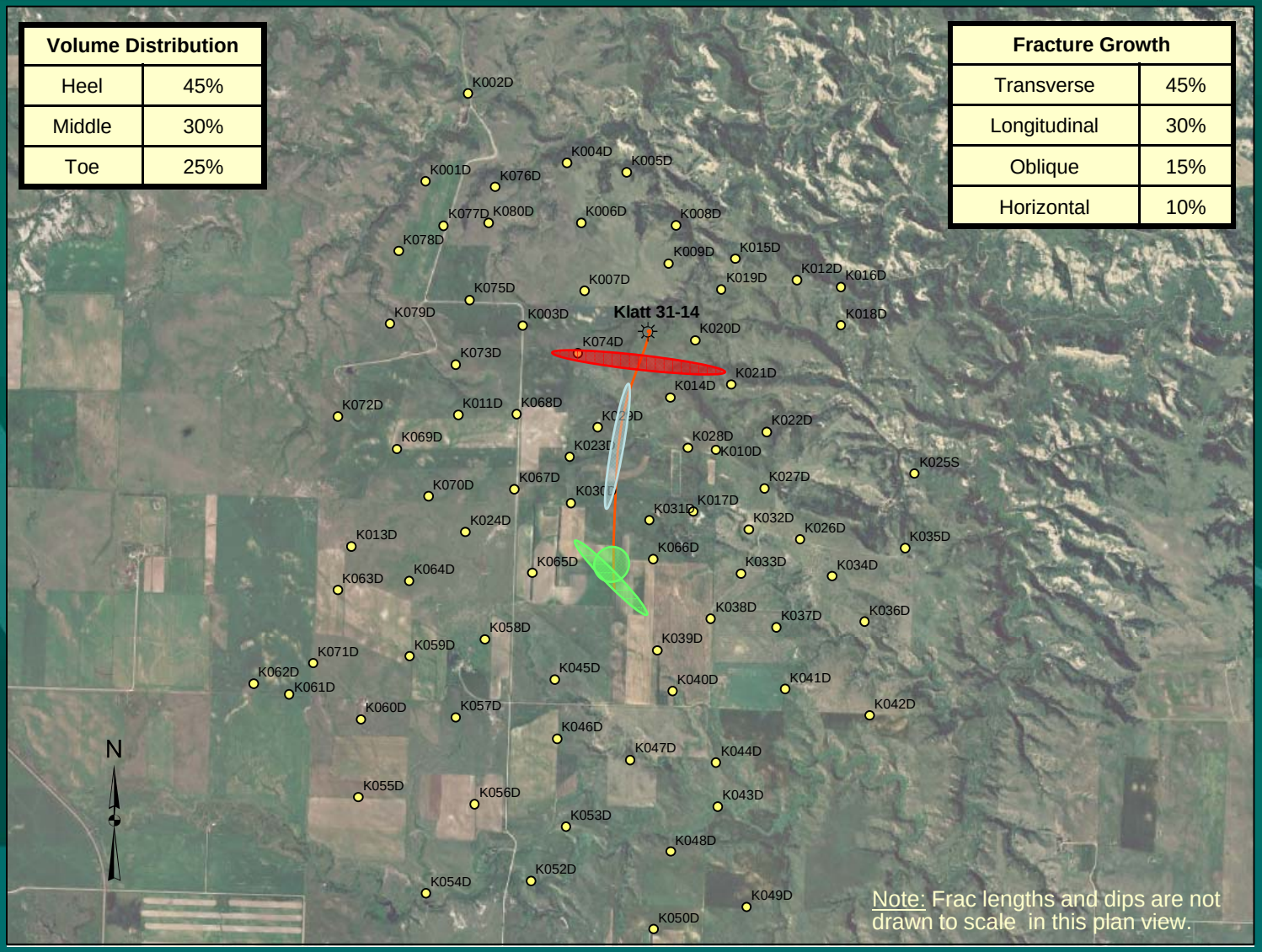
- Green Ellipse(s): 25% of the volume pumped – Toe of the lateral section
- Blue Ellipse(s): 30% of the volume pumped – Middle of the lateral section
- Red Ellipse(s): 45% of the volume pumped – Heel of the lateral section

# Map View w/ Array Layout - 9/5/2007 Injection (Stage 2)

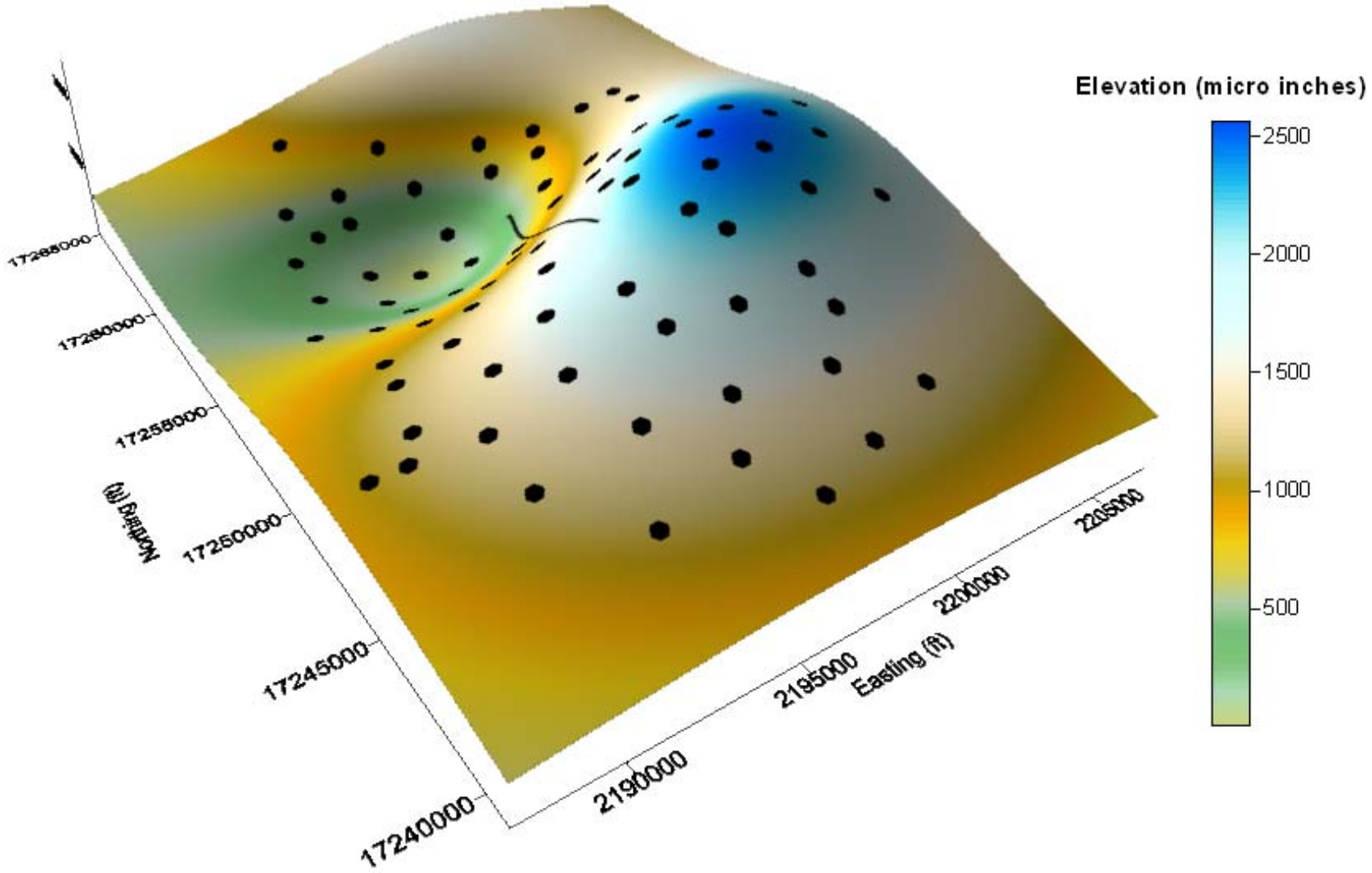
Pinnacle

| Volume Distribution | |
|---|---|
| Heel | 45% |
| Middle | 30% |
| Toe | 25% |

| Fracture Growth | |
|---|---|
| Transverse | 45% |
| Longitudinal | 30% |
| Oblique | 15% |
| Horizontal | 10% |



# 3-D Surface Theoretical Deformation - 9/5/2007 Injection (Stage 2)



# Summary of Results

Pinnacle

- Two fracture treatments were pumped on Well Klatt 31-14H, the first on 7/23/2007 and the second on 9/5/2007. Surface tiltmeter mapping technology was used to map fluid distribution & fracture volume percentage.

- For the treatment performed on 7/23/2007 the volume distribution along the lateral is:
  - Heel: 10% +/-2%
  - Middle: 40% +/- 14%
  - Toe: 50% +/- 12%

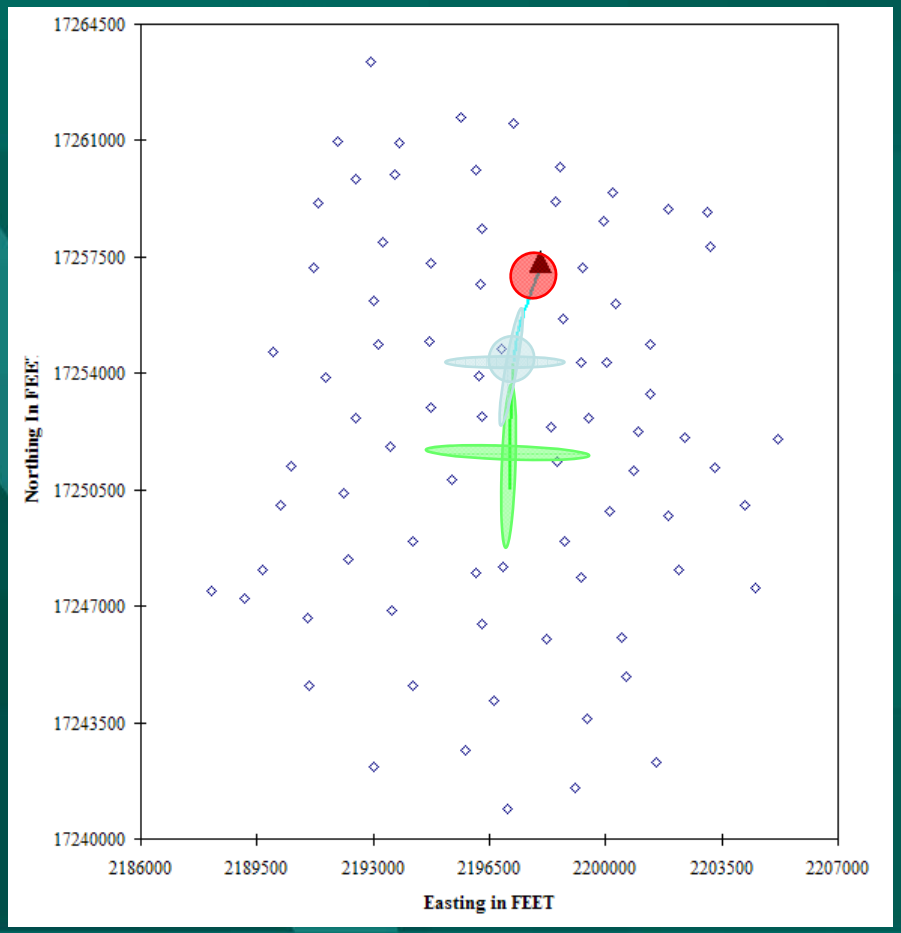
- For the treatment performed on 9/5/2007 the volume distribution along the lateral is:
  - Heel: 45% +/- 11%
  - Middle: 30% +/- 11%
  - Toe: 25% +/- 7%

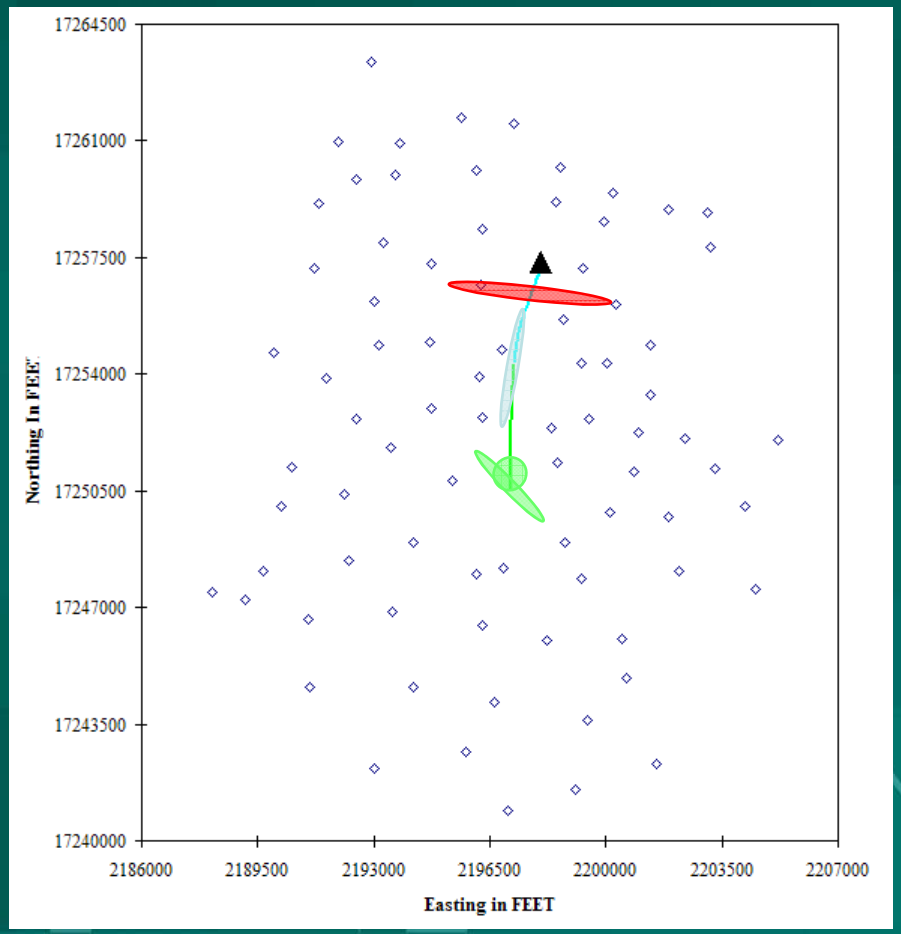
# Summary of Tilt Mapping Results for Well Klatt 31-14H

| Stage | Job Date | Injection Times (Local) (Volume) | Perfs. Depth TVD (ft) | Volume Percentage | | |
|---|---|---|---|---|---|---|
| | | | | **Heel** | **Middle** | **Toe** |
| **1** | **07/23/07** | **8:01 – 9:24 (3,892 bbls)** | **10,858** | **~10% Horizontal** | **15% - Transverse**<br>**15% - Longitudinal**<br>**~10% Horizontal** | **30% - Transverse**<br>**20% - Longitudinal** |
| **Totals** | | | | **10%** | **40%** | **50%** |
| **2** | **9/5/07** | **15:24 – 17:43 (6,553 bbls)** | **10,858** | **45% - Transverse** | **30% - Longitudinal** | **15% - Oblique***<br>**10% - Horizontal** |
| | | | | **45%** | **30%** | **25%** |

** For the fracture component in the Toe, azimuth is roughly N45W*

# Comparison between the 7/23/2007 and 9/5/2007 Injection



# Conclusions

Pinnacle

- Noticeable unequal fluid entry into heel, toe and middle portions of lateral during both injections
- Second stage may have effectively stimulated portions of the lateral that were missed the first stage
- Longitudinal fracturing may have been predecessor to turning transverse
- Entry of fluid into the formation may not have been related to exit of the fluid out pipe
- Even distribution of fluid outside uncemented casing may be difficult to control
- Low viscosity fluids and more volume on stage 2 may have contributed to distribution in different portions of lateral from stage 1

# Recommendations

Offset development should keep the approximate N-S lateral orientations to ensure transverse fractures

- Maximize exposed reservoir surface area
- Encourage fracture development far from WB

- Re-examination of decision to stimulate OH might be warranted. It is possible that SRV is being sacrificed for ease of completion

- When k is low, re-consider forcing fluid exit from pipe into coinciding with fluid entry into formation (cement + multiple stages)

- On a future 5-1/2" lateral, consider treatment well microseismic to determine additional geometric parameters

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