

# A Rose By Any Other Name...



## THE SETTING

- Rose Field in Central California
- Horizontal Wells
- McLure Shale at 8000' TVD
- Low perm, naturally fractured



## THE BACKGROUND

EOG Resources is developing oil reserves in the McLure Shale, a Miocene-aged quartz-phase biogenic-source siliceous shale. The Rose Field, discovered in 2000, is near the North Shafter Field where initial vertical well fracturing had proven highly problematic. The track record for proppant placement at North Shafter was hit or miss, due to mid and far-field fracture complexity, and production suffered rapid decline rates and poor economics.

The productive portion of the McLure Shale is thin, around 40' thick with around 26% porosity, but low permeability averaging about 0.1 mD. The rock is naturally fractured but logs suggest the density of open natural fractures is low. The formation is significantly overpressured with a pore pressure gradient of 0.8 psi/ft. The rock is moderately soft with a modulus of about 1 million psi and a fracture closure (minimum stress) gradient averaging 0.87 psi/ft.

Previous experience with surface tiltmapping in North Shafter showed fracture orientations ranging from near horizontal to multiple orthogonal vertical fractures, consistent with complications from natural fracturing and indicating a low stress bias.

## PINNACLE PERFORMS

Based on poor vertical well performance and difficulties in placing proppant in nearby Shafter, a strategy incorporating long (2500') uncemented horizontal liners with a single hydraulic fracture treatment was

developed. This improved the likelihood of placing large fracture treatments and accessed a much larger reservoir volume. The half-mile completion interval undeniably adds complications and uncertainty in covering the entire interval with a single stage; so surface tiltmeters were utilized to monitor the frac treatments. Surface tiltmeters provide fracture orientation(s) and the volume distribution of frac fluid along the horizontal wellbores.

The laterals were aligned with the expected preferred fracture orientation (N30°E) based on borehole breakout and fracture imaging logs, thus aiming to create a longitudinal fracture traversing the length of the lateral. Generally, 7–10 perforation clusters were placed in the uncemented liner (average separation 350') and the perforation density was adjusted to balance treatment volume distribution along the lateral. On average, the treatments placed nearly 4000 bbls of 35# delayed borate crosslink slurry with just over 500,000# of 20/40 PRC proppant.

The goals of the surface tiltmapping were to determine azimuth and dip of the fractures and to identify the approximate location of the volume components. Are longitudinal components created as expected? Were the treatment volumes effectively distributed across the half-mile of uncemented lateral? 40 surface tilt sites were distributed over an 8 square mile area.

Distinct changes in tilt trends were observed on many treatments, where fractures changed from longitudinal to transverse, or shifted from toe to heel. Figure 2 shows an example of raw data from one site during a fracture treatment where tilt signals changed abruptly coincident with a significant treatment pressure rise, indicating that a bridging loss of the longitudinal fracture component had occurred. Figure 3 shows the mapped results for the first half of the treatment while Figure 4 shows the mapped results for the last half of the treatment, showing that the longitudinal component stopped growing and the remainder of the treatment consisted of only transverse fracturing at the toe and horizontal fracturing at the heel.

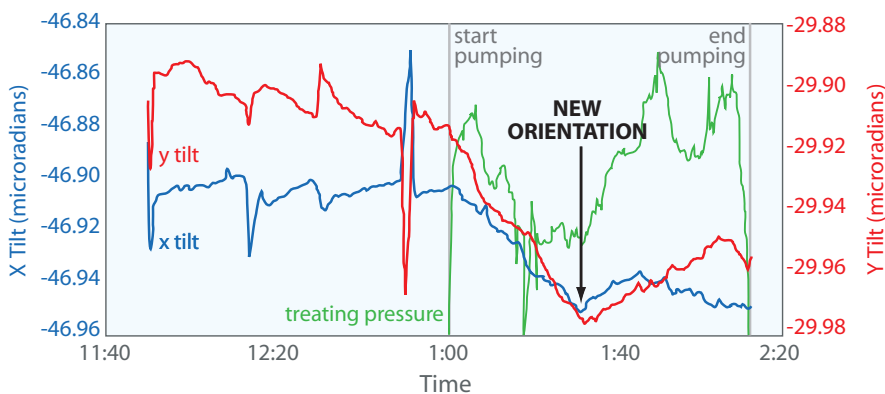
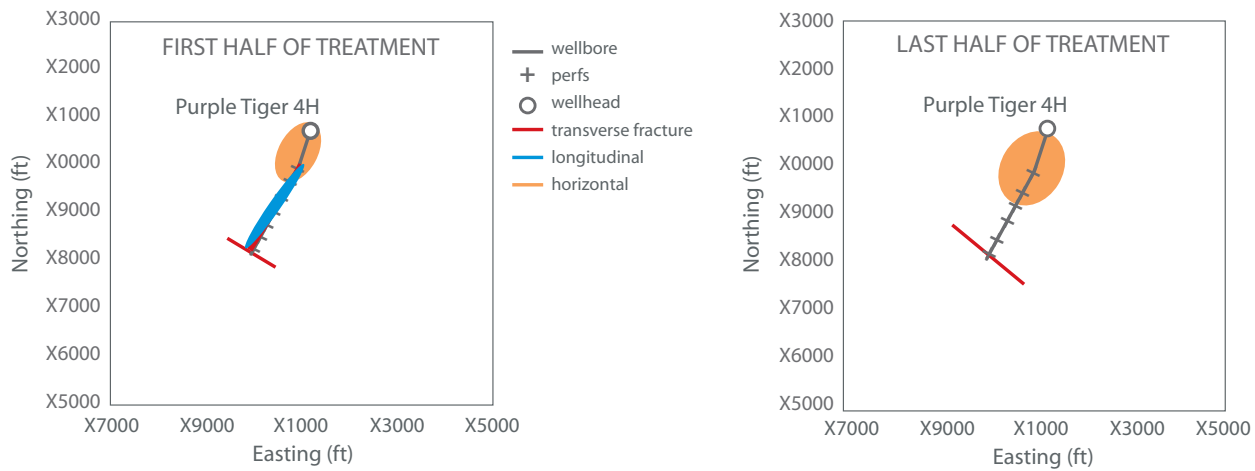


Figure 2. Raw tilt signal from single site shows change in fracture orientation just prior to 1:40 pm.



Figures 3 (left) and 4 (right).

The table at bottom left shows data from all of the wells mapped to date: the average fracture distribution is 45% transverse, 36% longitudinal and 19% horizontal. If there is a preferred fracture orientation, it does not appear to be longitudinal to the lateral orientation of N30°E. The lack of a strongly preferred frac orientation and variability from well to well is likely due to a small difference between the overburden and the principal horizontal stresses. This allows for multiple azimuths, which are influenced by frac initiation direction, natural fracture orientation and density, and local variations in the stress field. Perforation cluster flowrate, treatment induced stress changes and proppant-bridging events may also play some role. Fracture volume placement also varied with an average frac placing about 40% at the heel, 20% in the mid-lateral and 40% at the toe. The smaller volume measured in the mid-lateral region is likely due to “stress-shadowing” from adjacent transverse fractures near the heel and toe. More details of this project can be found in SPE 83503.

**THE RESULTS**

1-year cumulative production results suggest that larger transverse and horizontal fracture components lead to the most favorable production response. Overall coverage of the half-mile long laterals was reasonable, but there is opportunity for improving mid-lateral coverage. 1-year cumulative production results suggest that larger transverse and horizontal components lead to the most favorable production response, while a larger longitudinal component (the original completion intention) is associated with increased water production due to height growth. Because the average results show more transverse growth than longitudinal, the current wellbore orientation appears to be close to optimum, given that fracture growth in multiple planes is inevitable due to the low stress bias.

**FRACTURE COMPONENT TYPE, VOLUME %**

WELL	ORIENTATION			LOCATION		
	Longitudinal	Transverse	Horizontal	Heel	Mid-Lateral	Toe
Betty Boop 6H	25%	40%	35%	50%	10%	40%
Betty Boop 6H Refrac	5%	90%	5%	40%	5%	55%
Good Show 4H	55%	35%	10%	45%	20%	35%
Lincoln 3H	20%	75%	5%	20%	10%	70%
Lincoln 5H	100%	0%	0%	50%	25%	25%
Purple Tiger 3H	25%	25%	50%	20%	20%	60%
Purple Tiger 4H	25%	45%	30%	40%	10%	50%
Purple Tiger 5H	30%	50%	20%	50%	30%	20%
Purple Tiger 6H	35%	45%	20%	50%	30%	20%
<b>Overall Average</b>	<b>36%</b>	<b>45%</b>	<b>19%</b>	<b>41%</b>	<b>18%</b>	<b>42%</b>

Houston 281-876-2323

Denver 720-344-3464

Calgary 403-516-2260

Bakersfield 661-335-7711

San Francisco 415-861-1097

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