Horizontal Image Analysis Applied to Fracture Stage Optimization in a US Gas Shale Reservoir*

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Abstract

Borehole image logs from 3 horizontal wells in the Barnett reveal significant variability in natural fracturing, faults and drilling induced fracture distribution along their laterals. The presence or absence of drilling induced transverse and longitudinal fractures can be directly linked to the changes in frac gradient and proppant placement during the fracture treatments and flowback response. A geomechanical study of all three wells identified the geometry of critically-stressed fractures and faults. Variation in differential stress along the lateral and changes in the geometry of critically-stressed fractures and faults can significantly alter the induced hydraulic fracture response (complex vs. planar fractures) in these stages, ultimately governing production response. We developed criteria to use drilling induced fracture patterns from horizontal borehole image data to optimize the fracture stage design, custom fitting the stimulation to lateral changes in stress anisotropy. From production histories, we show that stage-by-stage modification of the pump-ins, accommodating image derived information, improved frac efficiency and EUR, even in highly fractured laterals.

Procedure Overview

The 3 subject wells for this study are the Palomino 9H (Pal 9H) the Thoroughbred 2H (TB 2H) and the SE Mansfield 12H (SEM 12H). The Pal 2H & TB 2H are located in the westernmost area of the Dallas County. SEM 12H is located 14.6 miles to the SSW, in the southeastern corner of Tarrant County (Figure 1). These wells had horizontal micro-resistivity logs run in the laterals, from which structural features along their trajectory were identified. A full suite of logs were available for the pilot hole of TB 2H; these logs were used in combination with drilling parameters to produce a high-resolution Geomechanical Model (GM) around the borehole. The GM was projected onto the structures traversed by the laterals, and recalibrated to stress indicators observed in the image. The calibrated GM for TB 2H was evaluated in terms of the geometry of structural features inferred from the image log (i.e. fractures and faults), and the Critically Stressed Features (CSF) were identified (CSF's are fractures or faults that are more likely to fail, and hence become fluid-conductive, due to their relative position with respect to the present-day in situ stress field).

Comparison of CSF’s, HydroFrack injection pressures (by stage), and induced fractures in TB 2H enabled the derivation of criteria to improve fracture efficiency along the laterals.
The frequency of transverse (green arrow) and longitudinal fractures are presented Figure 2 above. The SEM #12 H had abundant transvers and longitudinal induced fractures indicating more isotropic stress and the lowest fracture pressure gradient. Most of the hydraulic stimulation stages propagated complex fractures in the SEM #12H. The toeward section of TB 2H had no induced fracture and high fracture pressure gradients. The upper section of the TB 2H had only transverse fractures and probably propagated more planar fractures.

Resistivity Image

The Figure 3 displays the fracture characteristics of the TB 2H lateral, which ranges in measured depth from 9400’ to 14760’ (5,360’ total). This lateral displays two prominent fracture strike directions. The dominant strike trend is oriented E-W and is almost exclusively comprised of cemented fractures (indicated by the magenta rose petals). This dominant strike trend has a greater tendency to dip to the N. The secondary fracture strike direction is oriented NNE-SSW and is dominated by closed fractures. Many of these fractures dip toward the ESE and are often lower-angle (>70°). The image log data includes 75 open fractures and 16 faults. The 5,360’ of the lateral averages a fracture density of one fracture every 4’.

Geomechanical Model and Critically Stressed Fractures

A full suite of logs available from the pilot hole was used to derive a geomechanical model consisting of horizontal stresses, pore pressure and overburden. The model was calibrated and validated by comparison with drilling events; geomechanical features determined from mud/drilling reports, and the interpreted image log. The calibrated model is displayed on the left side of Figure 3.

Averaged properties of the calibrated geomechanical model from the pilot hole were then adapted to the lateral by matching GR signatures between the wellbores, taking into consideration structural shifts (e.g. faults) as reported by the geo-steering report and/or results of the interpreted image, and recalibrating according to stress indicators on the lateral (Waters et al, 2006). Combination of the projected geomechanical model with the structural characteristics of the interpreted image enabled identification of critically-stressed fractures (CSF’s), which are defined as those fractures/faults that are positioned favorably to fail by shear, and hence, are more likely to be conductive (Zoback, 2007). CSF’s are displayed on the right side of Figure 4.

Barnett Stimulation Results

The SEM 12H and the TB 2H were both logged with lateral borehole image tools. The TB 2H and the SEM 12H were the first two laterals stimulated. At the time, our conclusions of the results of these lateral image logs were not fully formulated. However, stimulation designs for subsequent offsetting laterals will incorporate significant modifications based on the results of our analyses of the borehole image logs. The most significant conclusion from this investigation is that the drilling induced fractures mapped in the lateral image logs are a reasonable proxy for expected induced hydraulic fracture behavior. If we detect multi-planar drilling-induced fractures (e.g., both longitudinal and transverse), we can expect a greater propensity for multi-planar induced fracturing which would produce a wide Stimulated Reservoir Volume (SRV). If we observe single planar drilling induced fractures, (e.g., transverse fractures only), we can expect a greater propensity for single planar fractures, with a narrower SRV. An absence of drilling induced fractures can indicate high compressive stresses. This would indicate potential difficulty to initiate fractures and possibly higher fracture gradients (Olsen et al, 2014).

TB 2H showed relatively few drilling induced fractures in the first 2500' of the lateral. Fracturing in this section showed high stress gradients, and it proved difficult to place proppant. In fact, use of x-linked gel was necessary in several of the stages to place the desired proppant. At about 12,200' TD, the stresses in the lateral changed. The occurrence of drilling induced fractures increased, the fracture stress gradients diminished significantly, and the subsequent stages took proppant much more easily.

Specifically, stage 12 could not be completed in TB-2H. The initial breakdown generated a 1,500 psi pressure drop not observed in other completion stages. A fault is identified in state 12 and is dipping at 77° and strike aligned with SHmax. This fault is critically stressed and there are 60 critically stressed fractures in this stage, which caused the large leak-off and pressure drop. Stage 15 also had a critically stressed fault, but only had a four critically stress fractures and they were able to pump this stage with few leak-off problems (Figure 5).

The pump-in behavior is in a large degree a response to the leak-off properties associated to the presence of CSF's. In this case, it appears as if the abundance of CSF's in stage 12 prevented propagation of the hydrofrack, whereas the reduced amount in stage 15 caused some issues at the beginning, but not enough to hinder the procedure.

Conclusions

The presence and timely identification of CSF's is critical to account for excessive leak-offs that can jeopardize successful stimulation of frack stages. The degree of horizontal stress variability is critical to initiation and propagation complexity of hydrofracks in unconventional stimulation. Stress variability is reflected on the borehole wall in the form of longitudinal and transverse induced fracturing. Critically stress fractures and horizontal stress variability can be used to determine the potential communication with offset horizontal wells. Image and dipole sonic logs enable the identification of induced fracturing, structural changes, and stress variability, and hence are vital on the prediction of key parameters for hydrofrack design. Knowledge of the underlying controls on Frack propagation enables optimization of hydrofrack parameters leading to cost reduction and efficiency increase of the stimulation.

References Cited

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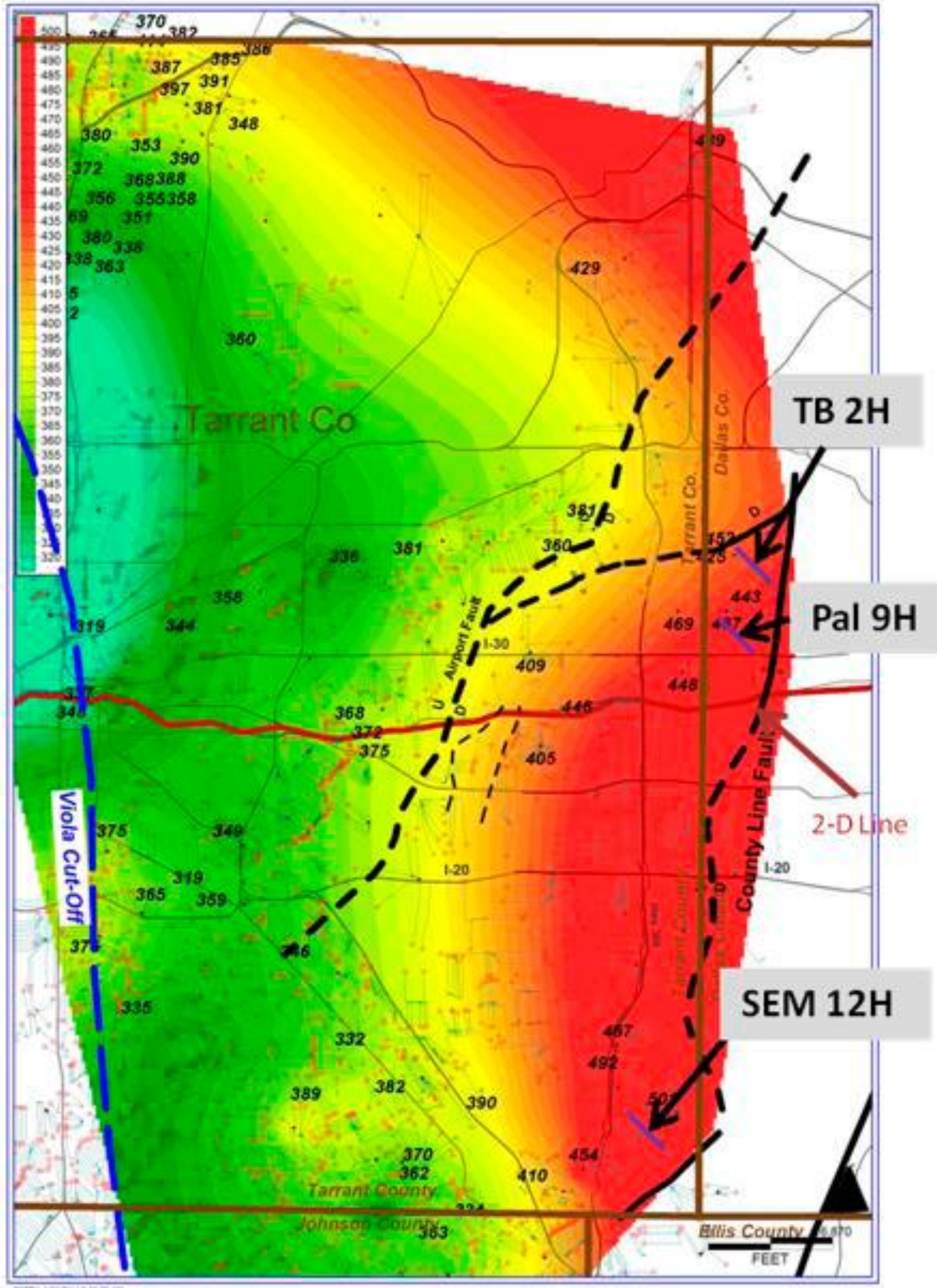
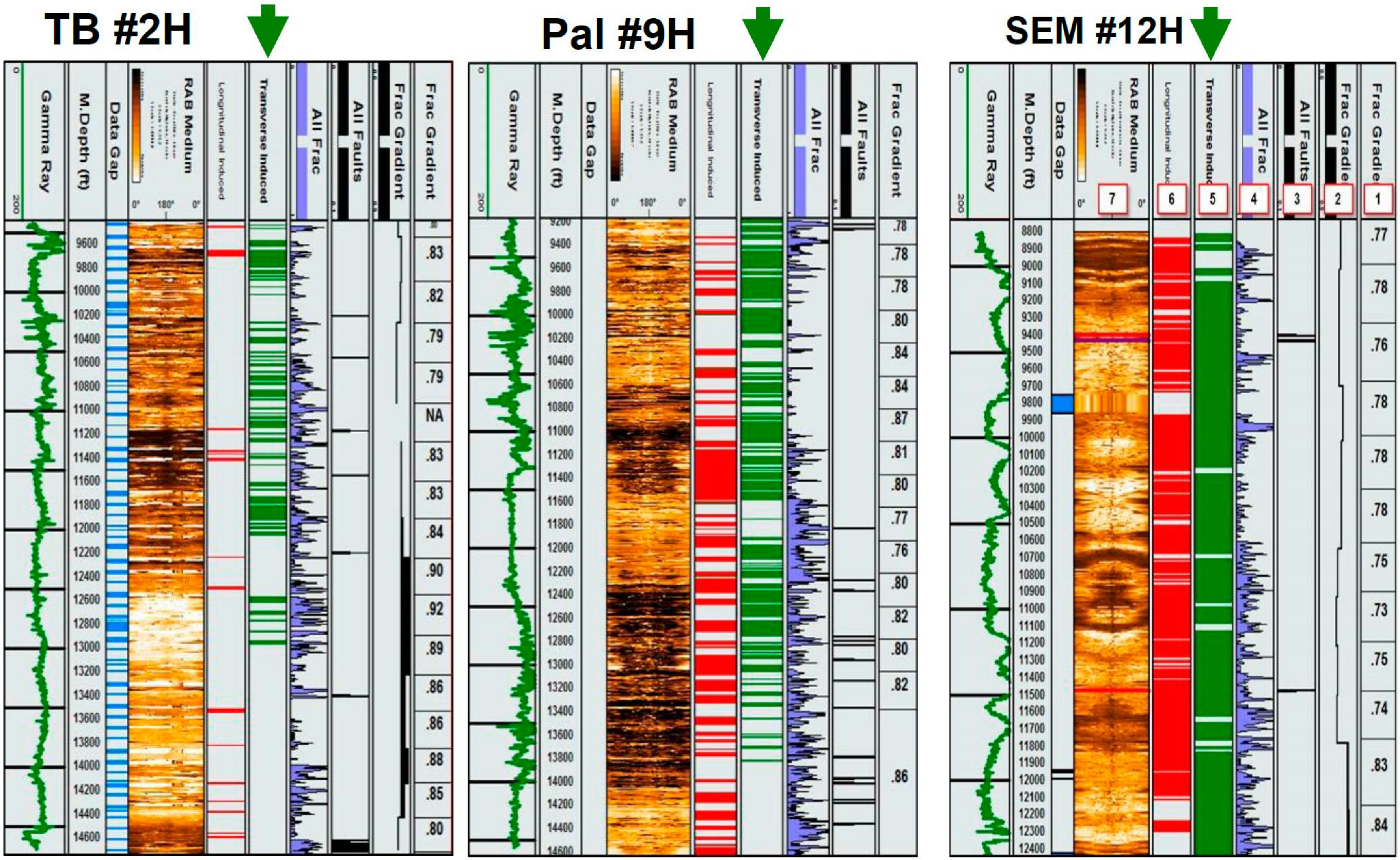


Figure 1. Geographical location of wells in this study.



Well	# of Fractures	Faults	Longitudinal Induced	Transverse Induced	Average Frac Gradient
Mansfield SE 12H (SEM 12H)	889	3	Abundant	Abundant	0.77
Thoroughbred 2H (TB 2H)	1,330	16	Few	Moderate	0.84
Palomino 9H (Pal 9H)	3,451	16	Moderate	Moderate	0.80

Figure 2. Frequency of transverse and longitudinal fractures

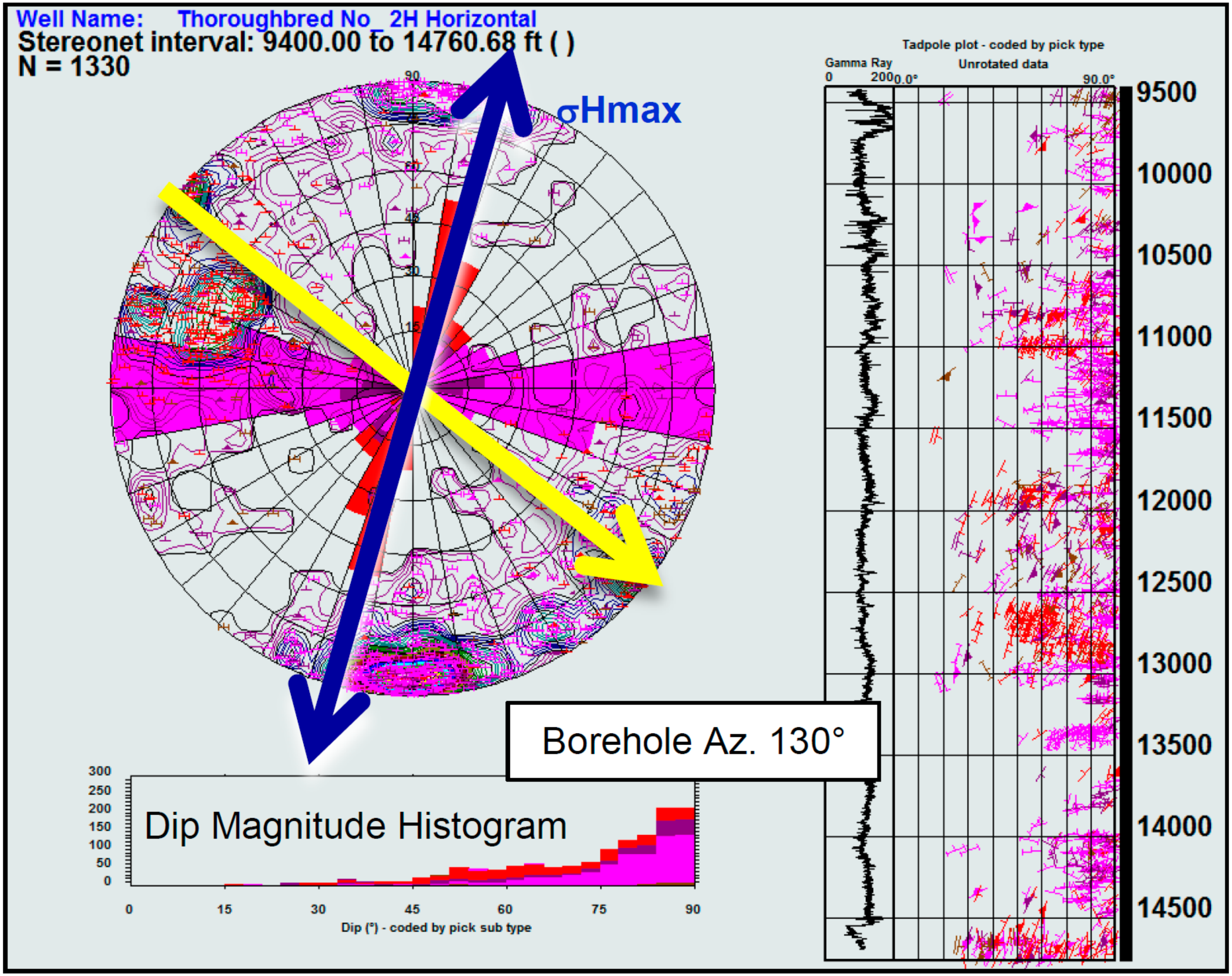
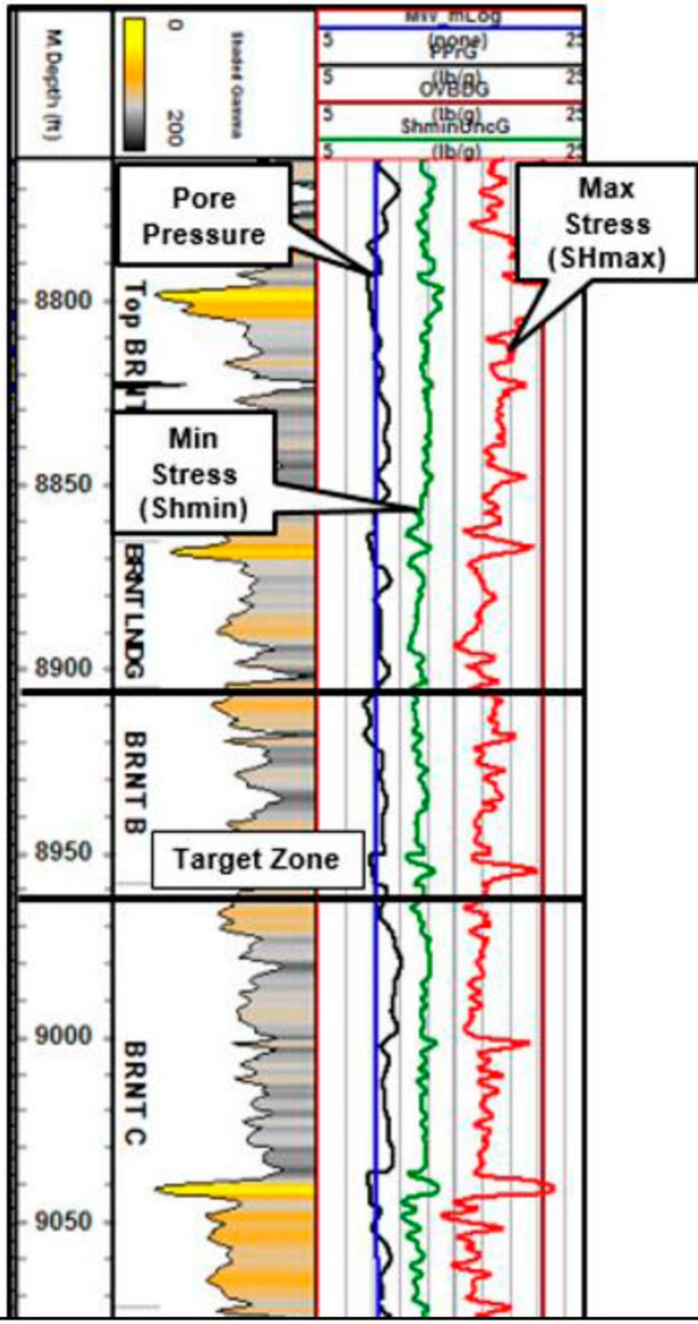
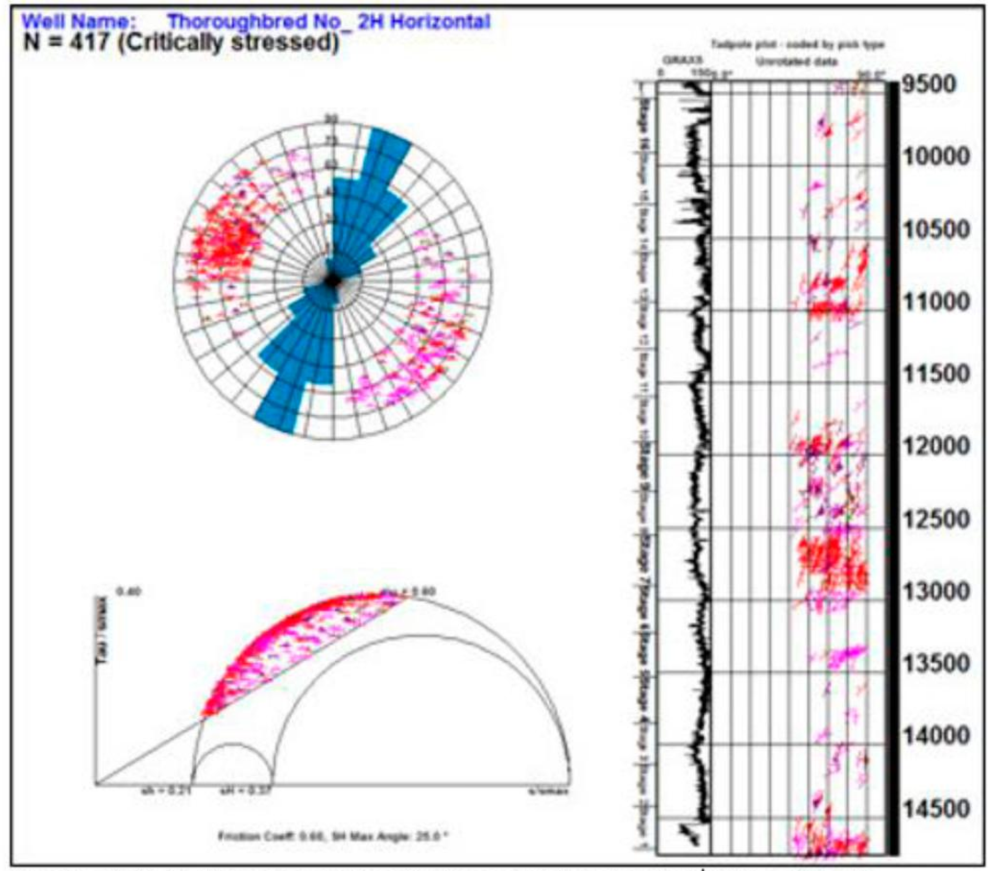


Figure 3. The diagram displays the fractures identified in the TB 2H from a measured depth of 9400’ to 14760’ (5,360’ total).





On the left is the geomechanical model for the TB 2H vertical pilot hole with the target zone labled. Above on the right side of the diagram is the tadpole plot indicating where the critcally stress fractures (CSF) are most abundant. There are a large number of critically stressed fractures from the fault at 12,900' to ~11,900'. From 10,900' to 11,200' is another area where the number of CSF increase. The frac stage at 11,168 had a high angle critically stress fault and more than 60 critically stressed fractures and was not successfully pumped.

Figure 4. TB 2H Geomechanical Model and Critically Stressed Fractures

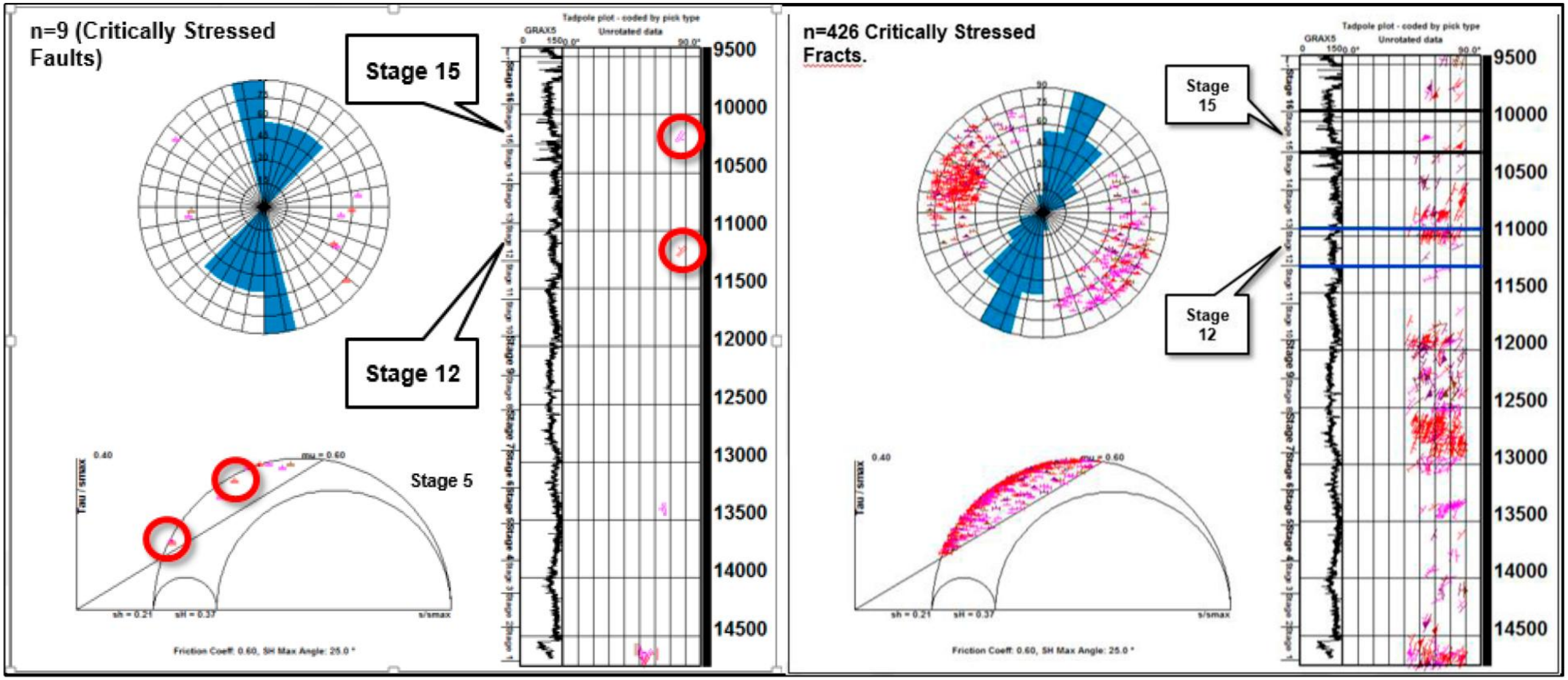


Figure 5. TB 2H Critically Stressed Faults (Left Side) and Fractures (Right Side).