Prediction of Hydraulic Fracture Damaged Zone Geometries in the Woodford Shale in Arkoma Basin using Discrete Fracture Network Models*

Sayantan Ghosh[1] and Seth Busetti[2]

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[1]University of Oklahoma, Norman, Oklahoma, United States (Sayantan.Ghosh-1@ou.edu)
[2]ConocoPhillips, Houston, TX, United States

Abstract

Understanding natural fracture stimulation patterns in highly fractured shale reservoirs is important for determining drainage volume. In the absence of image logs, natural fracture parameters studied at Woodford Shale and Hunton Group Limestone outcrops/quarries were used to understand artificial hydraulic fracture propagation in an Arkoma Basin well located 20-25 miles to the east of the outcrops. The outcrop fracture parameters were used as input into FracMan™ discrete fracture network simulator to match the microseismic geometry from three hydraulic fracture stages. The simulations and matched microseismic geometry provide insights into the mechanical effect and average fracture permeabilities of the Woodford Shale and bounding formations.

The simulator predicts a lower than 2% fluid efficiency (i.e., > 98% leak off) in the stimulated area. Reducing the number of natural fractures leads to high fluid efficiency (lower leak-off ratio) in areas where fluid flow is restricted to only dilatable fractures. In stages where flow through non-dilatable fractures was allowed, high efficiency was not obtainable. With increased fluid efficiency (using fluid loss additives or increasing fluid viscosity), a larger parent hydraulic fracture is created, though with more out of zone natural fracture stimulation. By setting a higher-pressure drop slope, which might result from using a high viscosity/high-density fluid or fine proppants, smaller stimulated volumes with larger inflated storage apertures were obtained.

Pumping at a higher net pressure was found to reduce the overall stimulation volume and open more, previously non-dilatable, fractures closer to the wellbore. Higher net pressure also caused more stimulation downward and out of the target zone. These observations suggest limiting the slurry rate. However, when a high slurry rate is applied for better proppant placement, the simulations indicate that the horizontal well should be placed high in the Woodford Shale due to downward reactivation of natural fractures. Shifting the well locations within the Woodford Shale in the simulator did not affect the overall microseismic cloud dimensions considerably. However, increasing lateral strain (i.e., stress shadow effect) with successive stages limited the stimulation to the formations closer to the wellbore and corresponding lengthening of the microseismic could in these formations.

References Cited

Blanton, T.L., and J.E., Olsen, 1999, Stress Magnitudes from Logs: Effects of Tectonic Strains and Temperature: SPE Reservoir Evaluation and Engineering, v. 2/1, p. 62-68.

FracMan™ Manual (Workshop), 2014, Golder Associates.

Neuhaus, C.W., 2011, Analysis of Surface and Downhole Microseismic Monitoring Coupled with Hydraulic Fracture Modeling in the Woodford Shale: Master's Thesis, Colorado School of Mines, Golden, CO.

Portas, R.M., 2009, Characterization and Origin of Fracture Patterns in the Woodford Shale in Southeastern Oklahoma for Application to Woodford Shale in Southeastern Oklahoma for Application to Exploration and Development: Master's thesis, University of Oklahoma, Norman, OK.

Suneson, N.H., 1997, The geology of the eastern Arbuckle Mountains in Pontotoc and Johnston Counties, Oklahoma. An Introduction and Field-trip Guide: Oklahoma Geological Survey Open-File Report OF 4-97, 25 p., Web Accessed July 23, 2017, http://ogs.ou.edu/docs/openfile/OF4-97.pdf

Prediction of hydraulic fracture damaged zone geometries in the Woodford Shale in Arkoma Basin using discrete fracture network models

Sayantan Ghosh (University of Oklahoma)

Seth Busetti (ConocoPhillips)

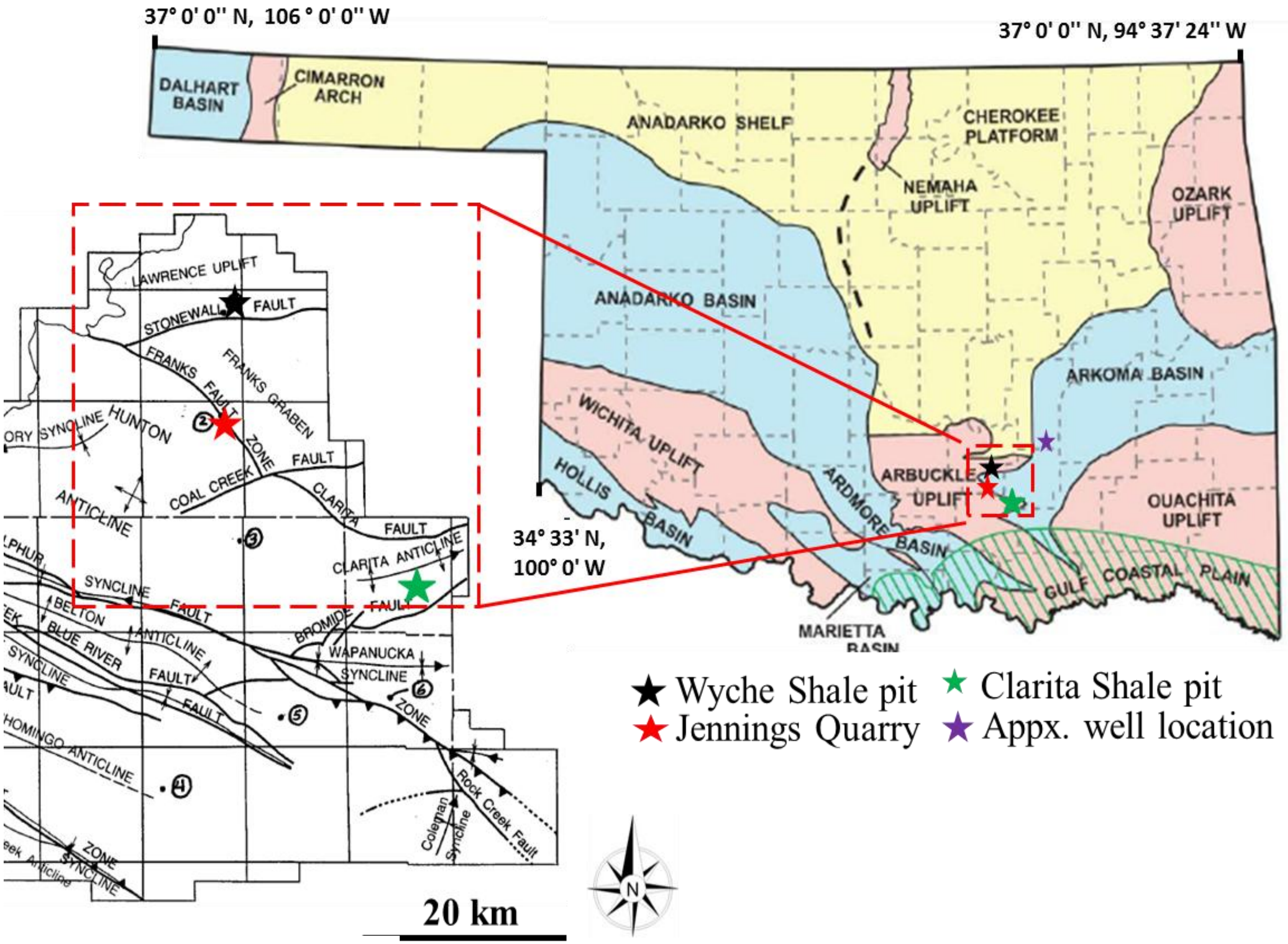
May 2, 2017

Objectives

- Determine formation properties by matching three hydraulic fracture stage geometries in a well using FracMan^{TM} Software.
- Perform sensitivity analysis, i.e., predict formation response under different:

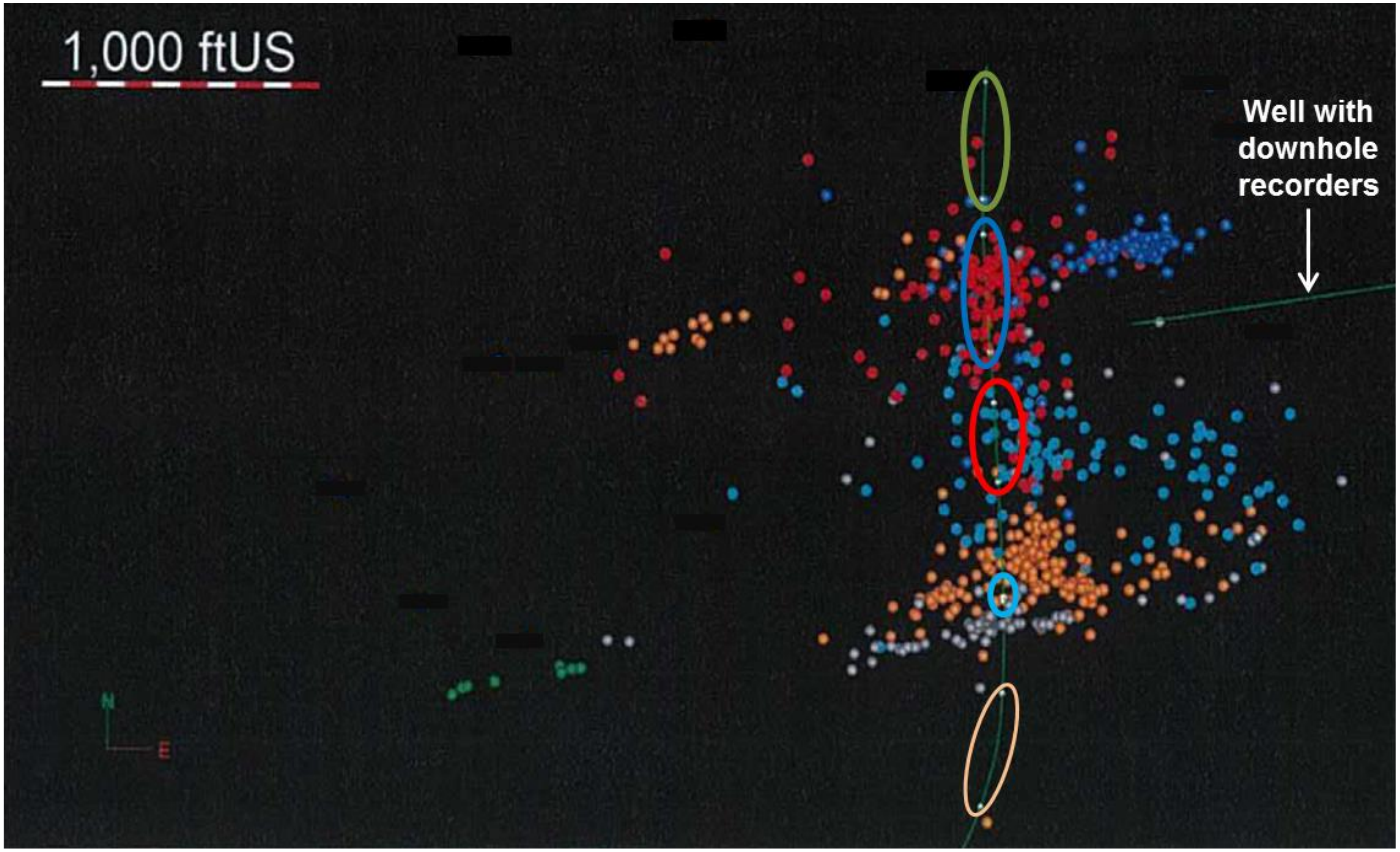
1. ***Horizontal stresses***
2. ***Net pressure***
3. ***Fluid efficiency*** *(Percent of total pumped fluid creating new surface area)*
4. ***Natural fracture intensities***
5. ***Fracture fluid pressure drop slopes***
6. ***Well location***

Field study and well locations



Modified from Suneson (1997)

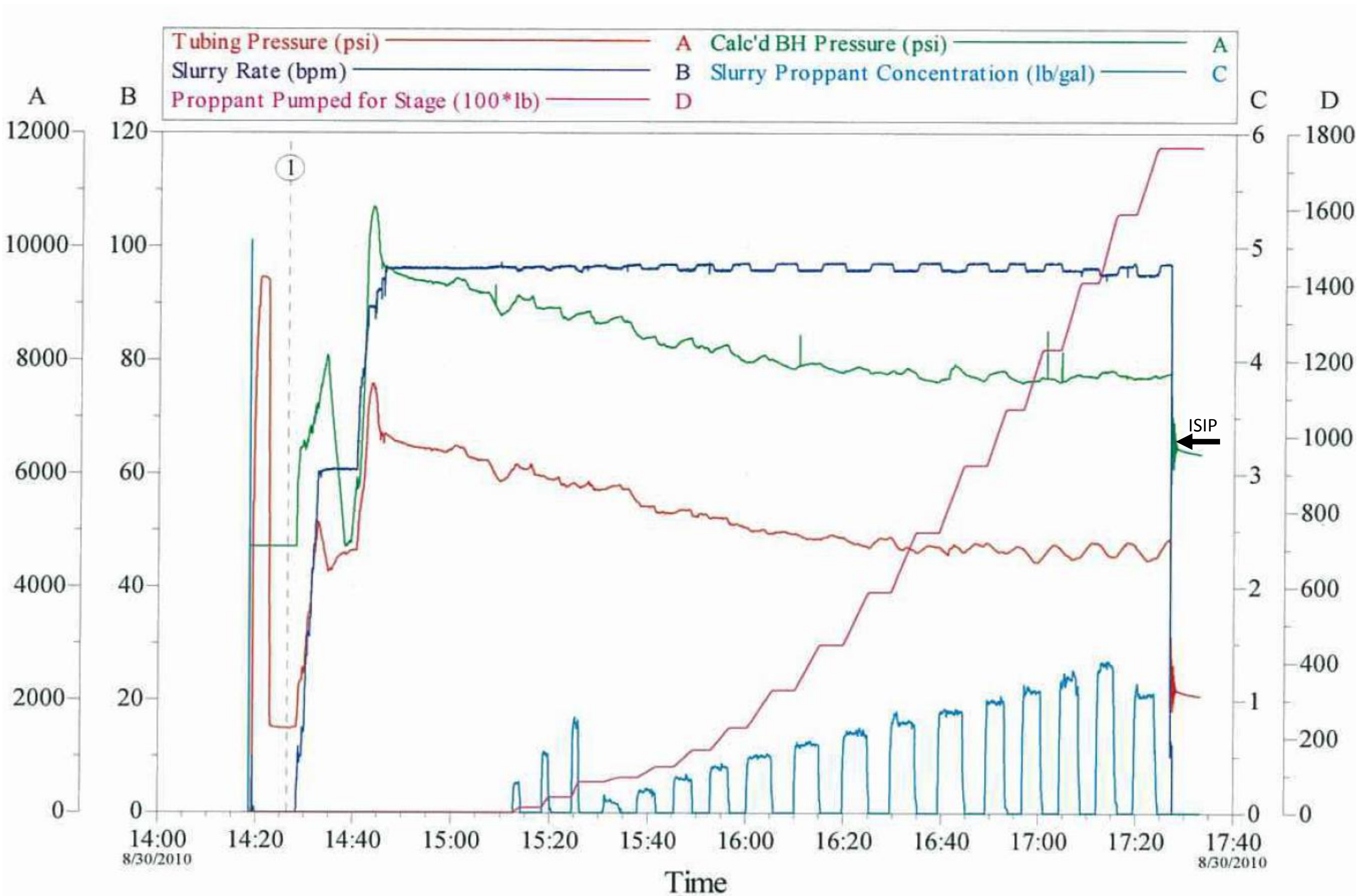
Map view of Stages 2-5 (surface and downhole)



- Stage 2 downhole
- Stage 3 downhole
- Stage 3 surface
- Stage 4 downhole
- Stage 4 surface
- Stage 5 downhole
- Stage 5 surface
- Stage 1 perforations
- Stage 2 perforations
- Stage 3 perforations
- Stage 4 perforations
- Stage 5 perforations

Modified from Neuhaus (2011)

Stage 2 hydraulic fracture treatment parameters

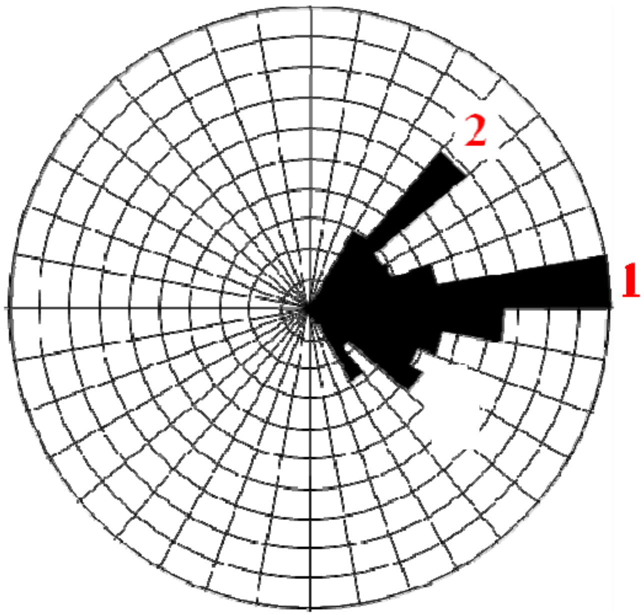


Similar HF parameters used for other stages

Modified from Neuhaus (2011)

Woodford and Hunton fracture orientations and intensities

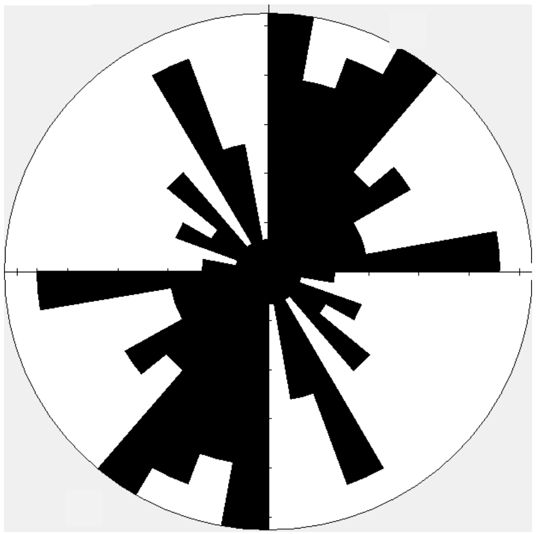
Woodford Shale



Modified from Portas (2009)

Two main fracture sets: E-W (**Intensity**: 0.256 Fractures/m), NE-SW (**Intensity**: 0.282 Fractures/m)

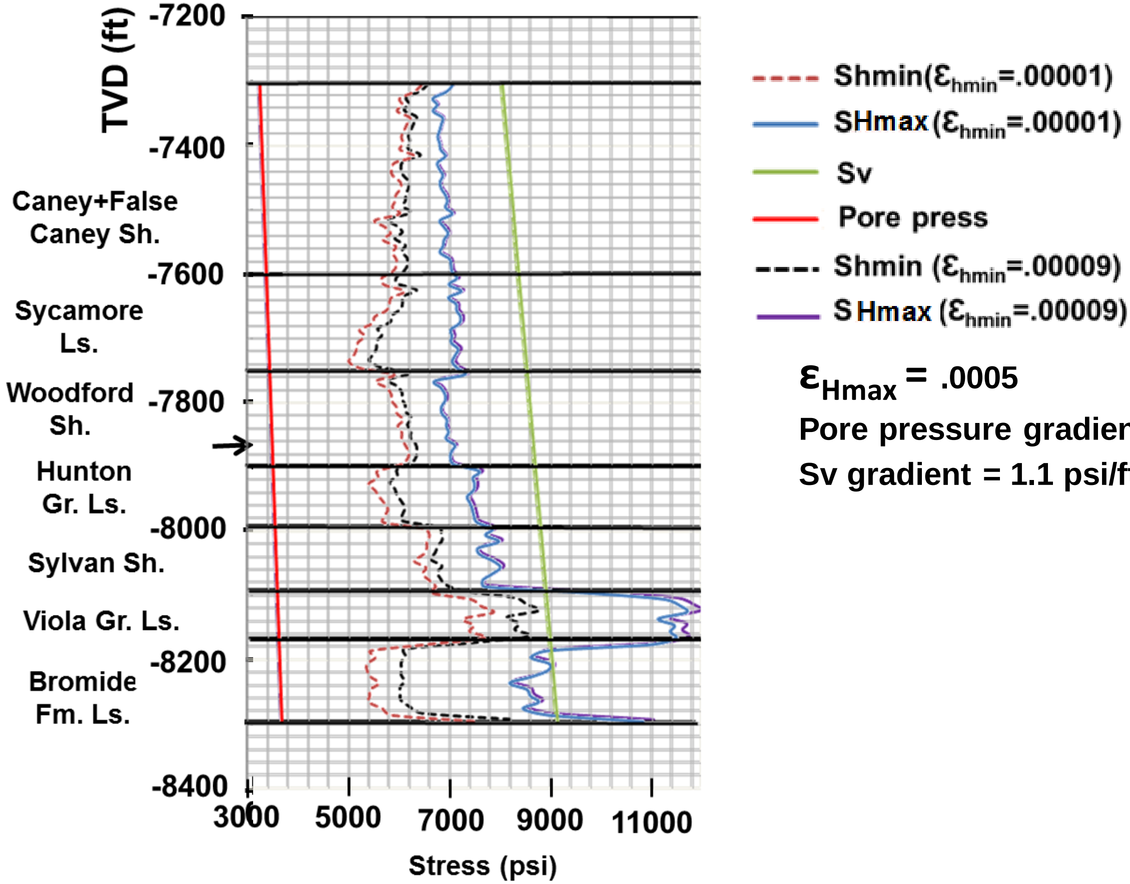
Hunton Group Limestone



3-4 main fracture sets: E-W (**Intensity**: 0.328 Fractures/m), N-S to NE-SW (**Intensity**: 0.279 Fractures/m), NW-SE (**Intensity**: 0.344 Fractures/m)

Note: Intensities of only large fractures, i.e., those with height > 1m are shown here.

Calculated stresses



ε_{Hmax} = .0005

Pore pressure gradient = 0.44 psi/ft

Sv gradient = 1.1 psi/ft

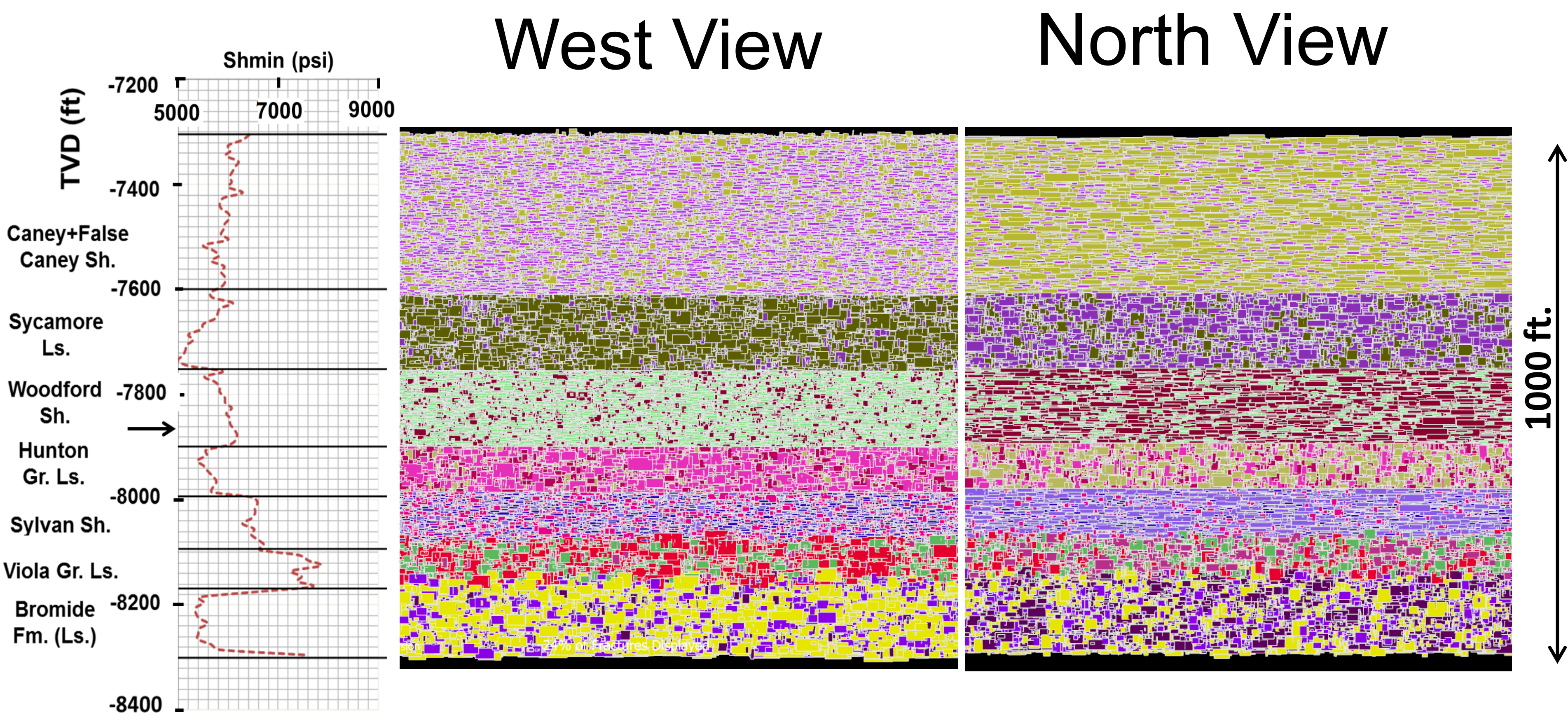
$$S_{hmin} = \frac{\nu}{1-\nu}(\sigma_V - \alpha P_P) + \frac{E}{1-\nu^2}\varepsilon_{hmin} + \frac{E\nu}{1-\nu^2}\varepsilon_{Hmax} + \alpha P_P$$

$$S_{Hmax} = \frac{\nu}{1-\nu}(\sigma_V - \alpha P_P) + \frac{E}{1-\nu^2}\varepsilon_{Hmax} + \frac{E\nu}{1-\nu^2}\varepsilon_{hmin} + \alpha P_P$$

Equations from Blanton and Olson (1999)

Note: σ_v is the same as Sv in the above equations

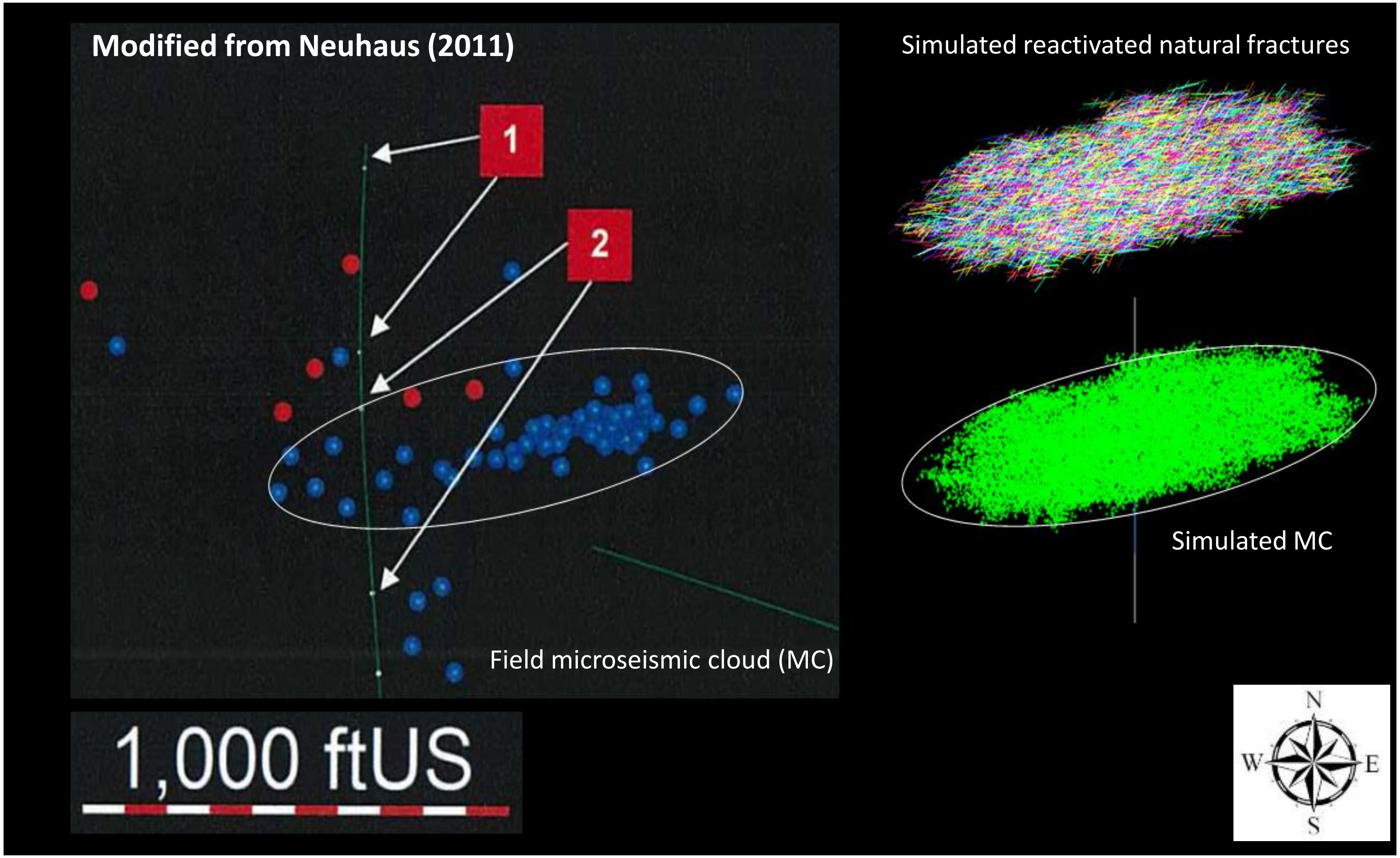
Static model



No vertical exaggeration

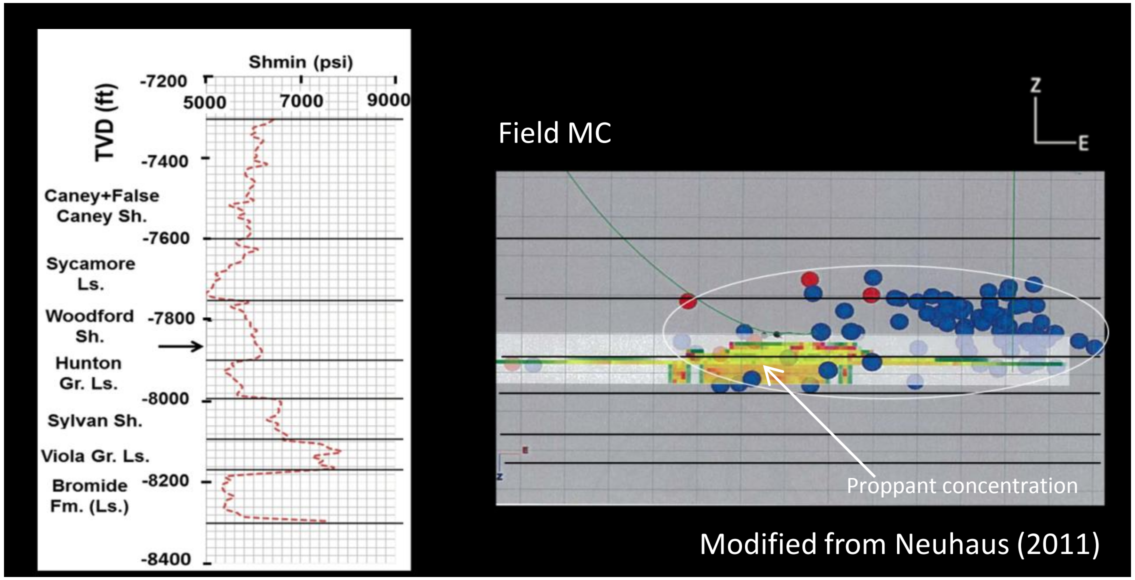
→ Appx. Horizontal well location

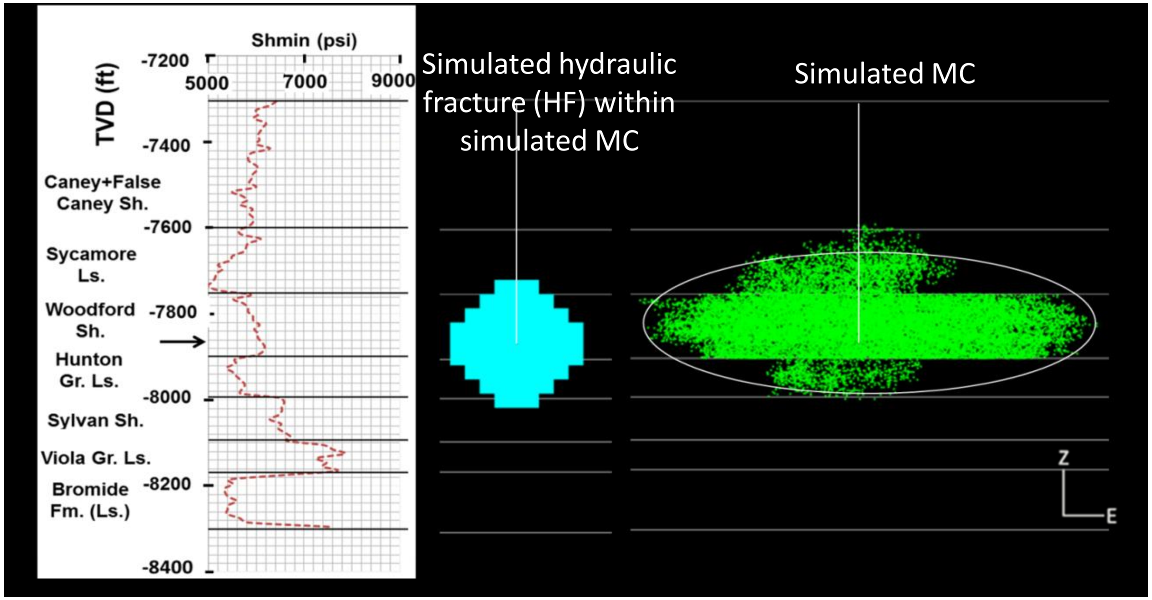
Geometry match (Stage 2 map view)



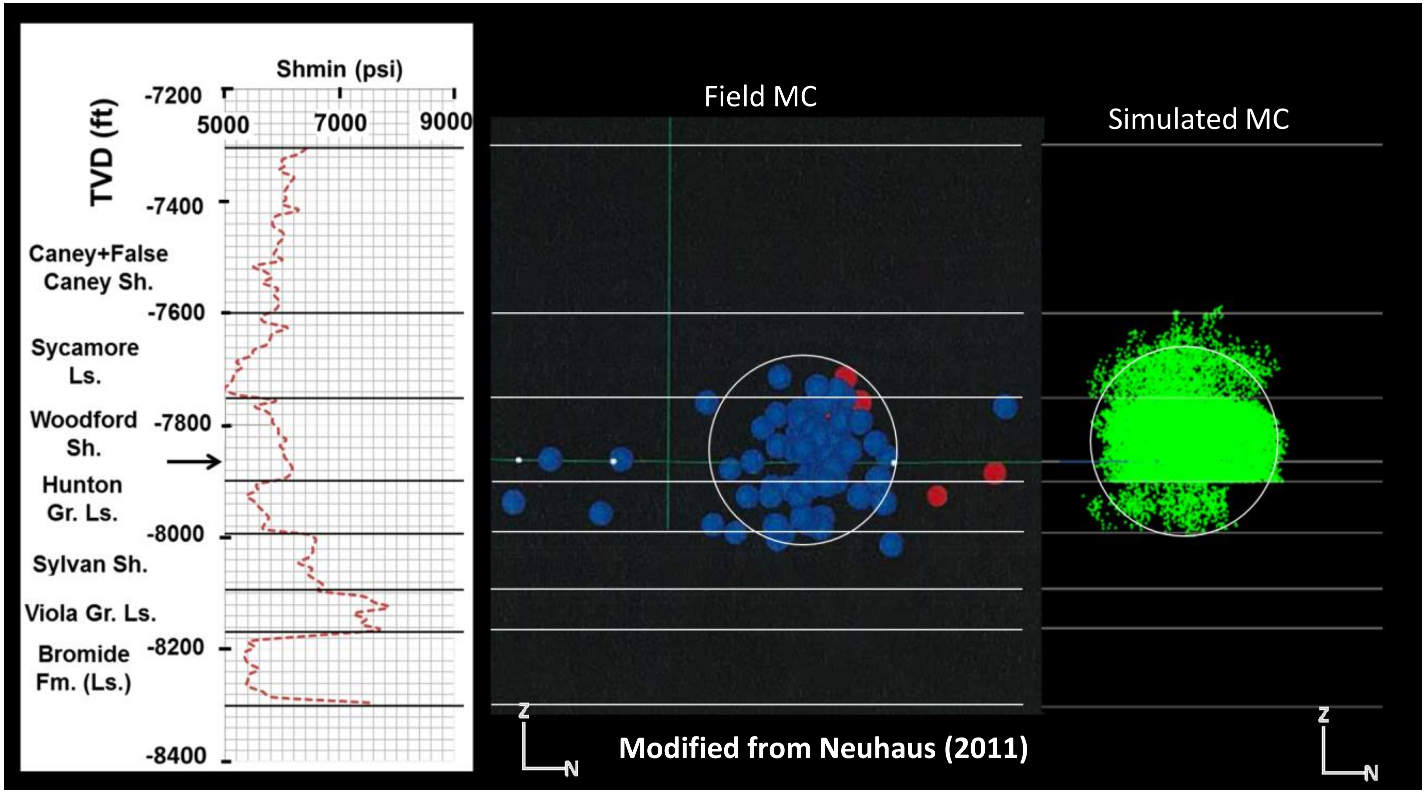
Flow through non-dilatable fracture	Flowback %	Max. storage aperture (m/mm)	Average storage aperture (m/mm)
No	25	0.006/6	.00589/5.89

Geometry match (Stage 2 north view)

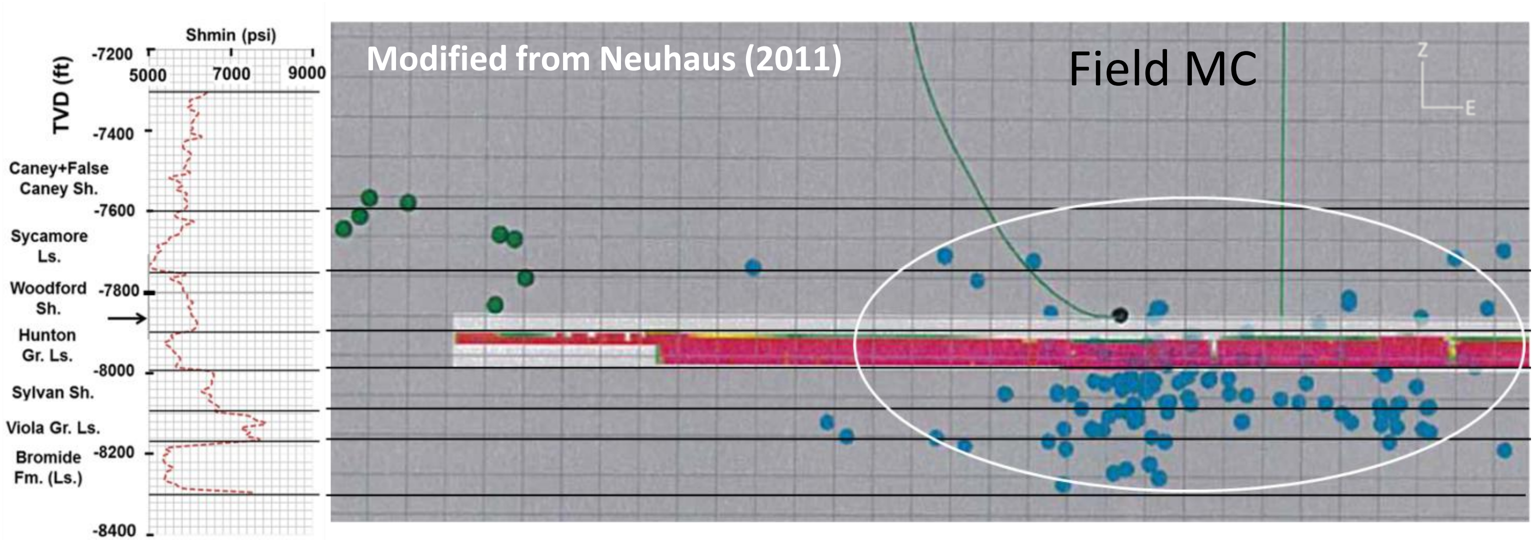


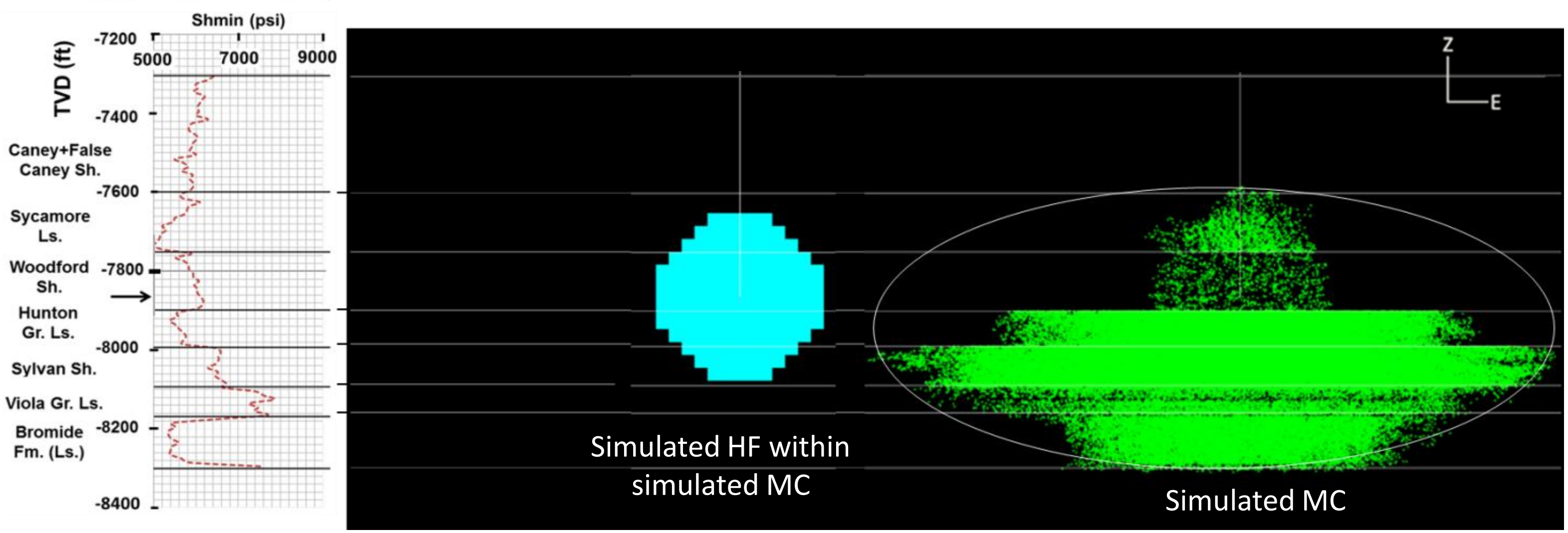


Geometry match (Stage 2 west view)



Geometry match (Stage 4 north view)





Flow through non-dilatable fracture	Flowback %	Max aperture (m/mm)	Average storage aperture (m/mm)
Yes	20	.0028/2.8	.00081/0.81

Stage 5 not shown

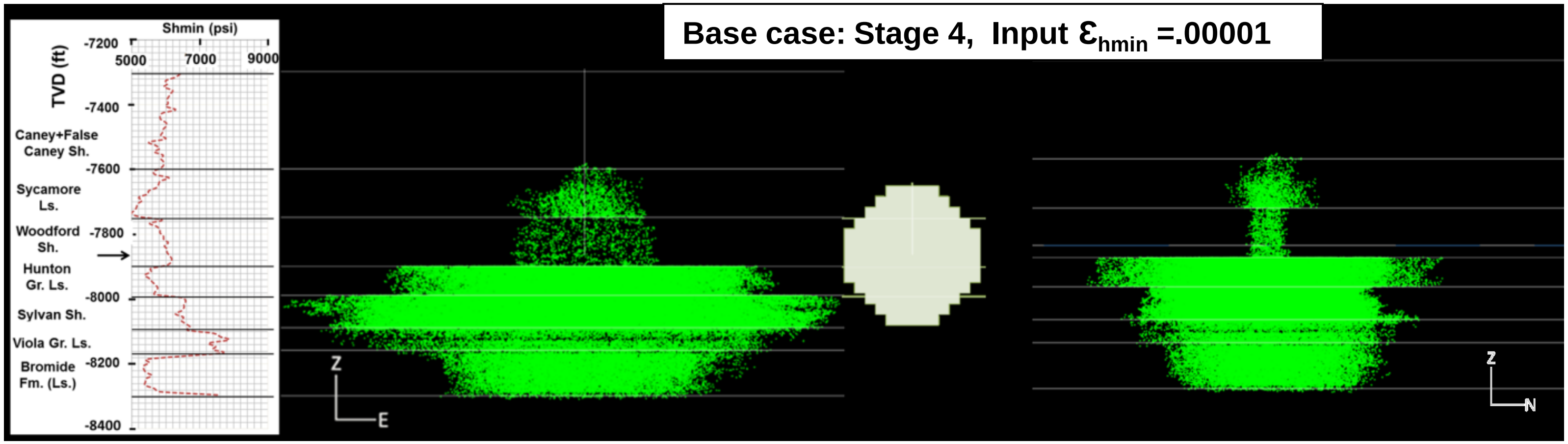
Fracture permeabilities (md) needed for geometry match

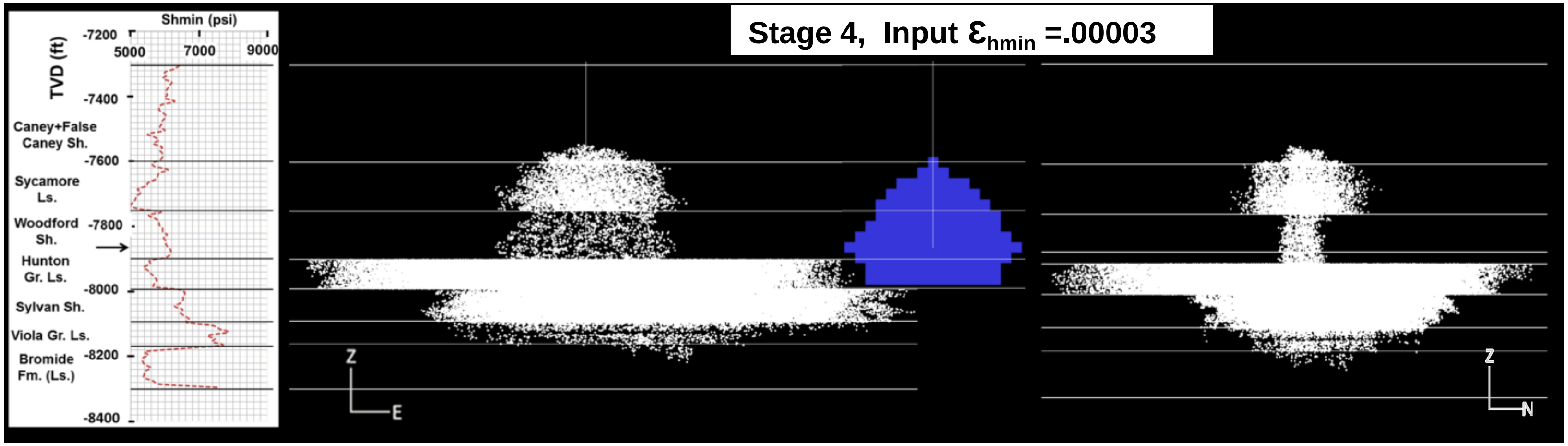
Caney perm (md)	.012
Sycamore perm (md)	.006
Woodford perm (md)	.003
Hunton perm (md)	.0045
Sylvan perm (md)	.011
Viola perm (md)	.025
Bromide perm(md)	.005

Viola Group Limestone (.025)> Caney Shale (.012)> Sylvan Shale (.011)> Sycamore Limestone (.006)> Bromide Formation (.005)> Hunton Group Limestone (.0045)> Woodford Sh (.003)

Sensitivity analyses

Effect of increase in ε_{hmin} (Stage 4)





No vertical exaggeration

At higher strain (stress):

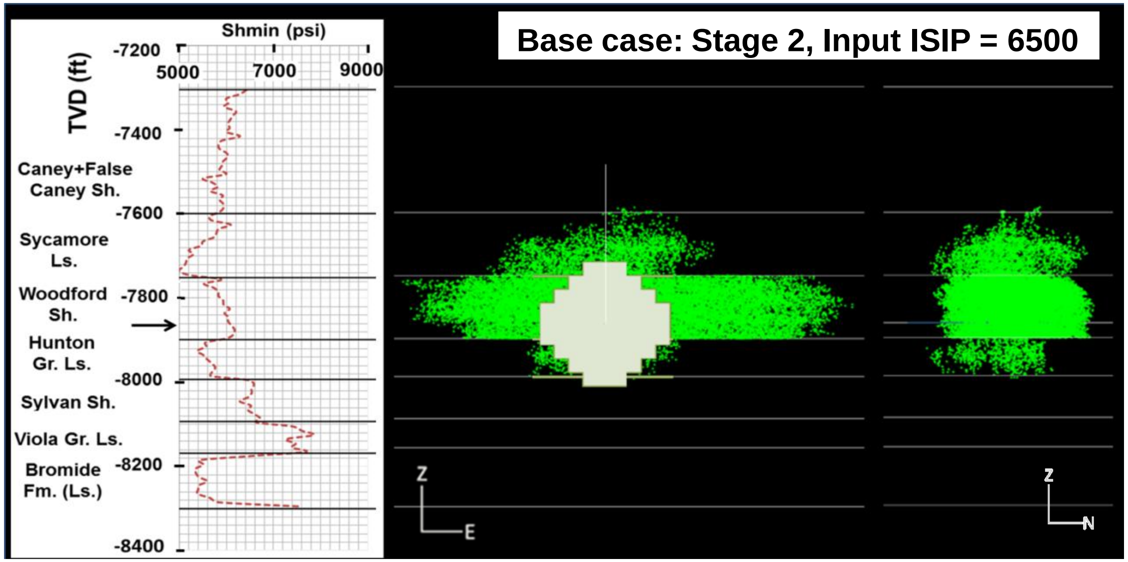
~14 % increase in overall stimulated volume

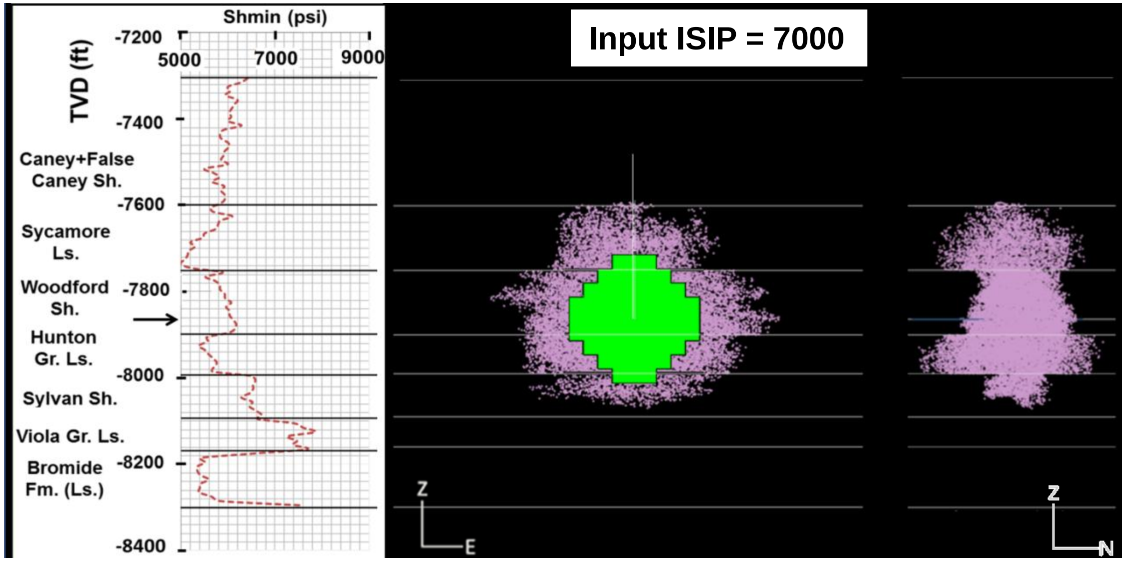
~29% increase in Woodford stimulated volume

- Also, more stimulation in Hunton and Sylvan.

-Almost none in Bromide.

Effect of change in ISIP (change in net pressure)





No vertical exaggeration

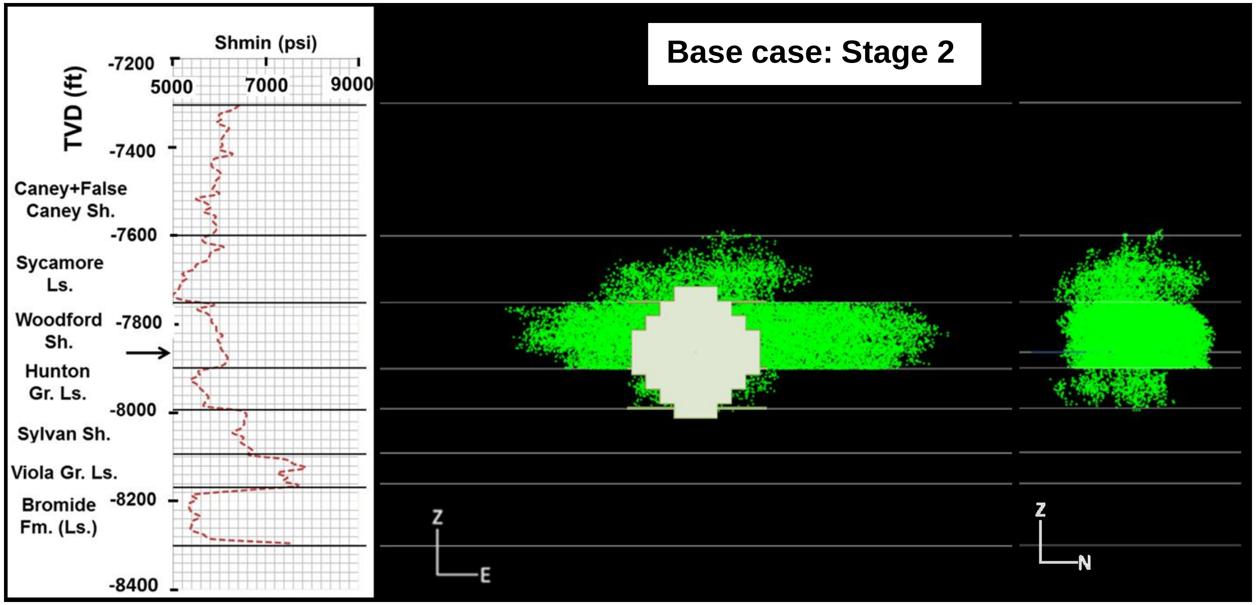
At a higher net pressure:

~**9-15%** decrease in overall stimulated volume

~74% decrease in Woodford stimulated volume

-Stimulated zone moves downwards

Effect of forcing higher fluid efficiency



Base case output efficiency: **1.4%**

At a higher forced efficiency:

~**2-14%** increase in overall volume

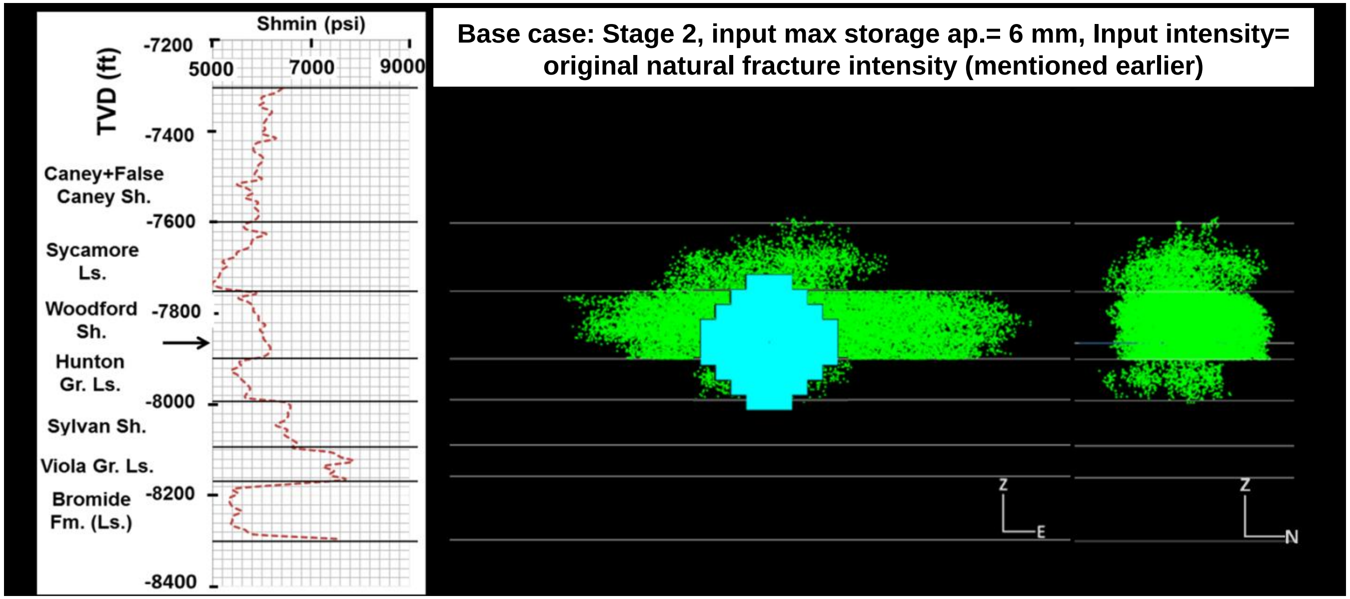
~**33%** decrease in Woodford stimulated volume

-geometry way off field geometry

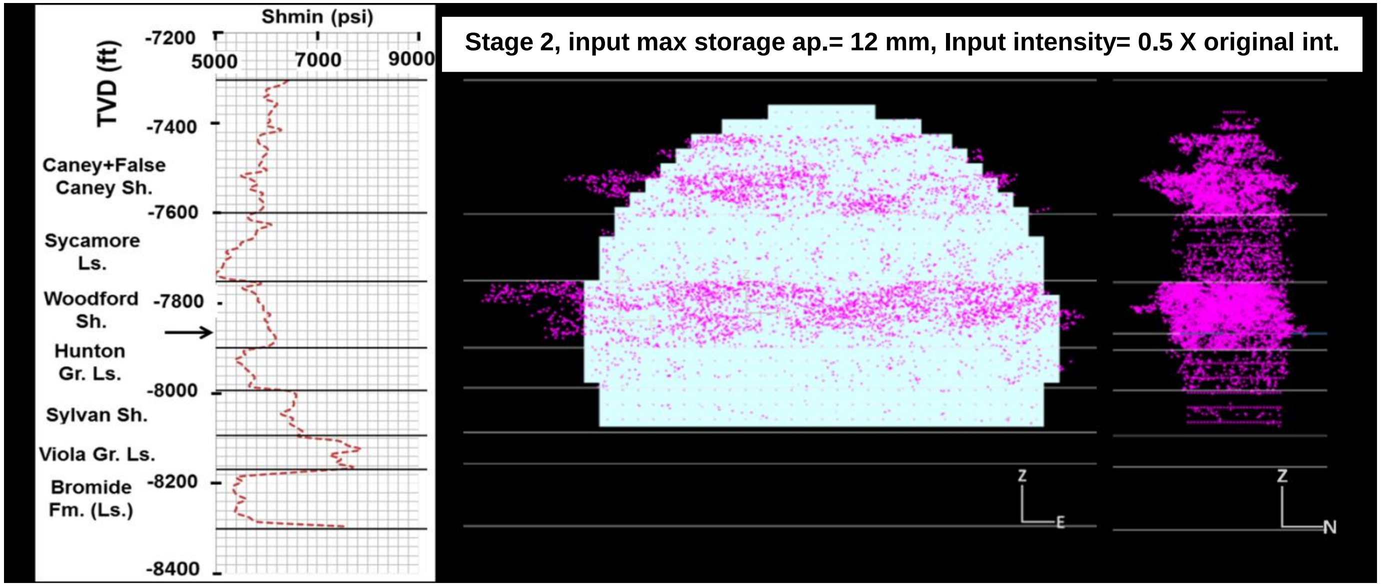
-HF stops at the top of Viola

No vertical exaggeration

Effect of halving natural fracture intensity and doubling max. fracture storage aperture (Stage 2)



Base case output efficiency: **1.4%**



At half intensity and twice storage aperture:

~ **200%** increase in overall stimulated volume.

~**14%** increase in Woodford stimulated volume.

-Output efficiency increases to **27%.**

-More out of zone growth.

-Geometry way off field geometry.

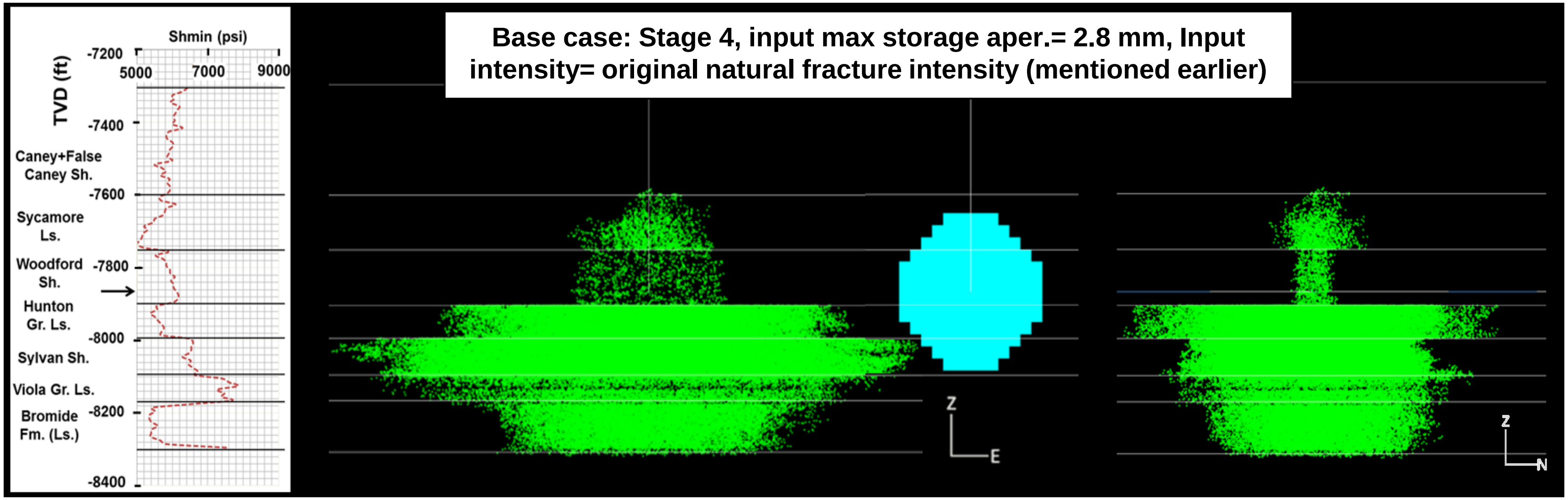
Note:

-Flow was **not allowed** through non-dilatable fractures.

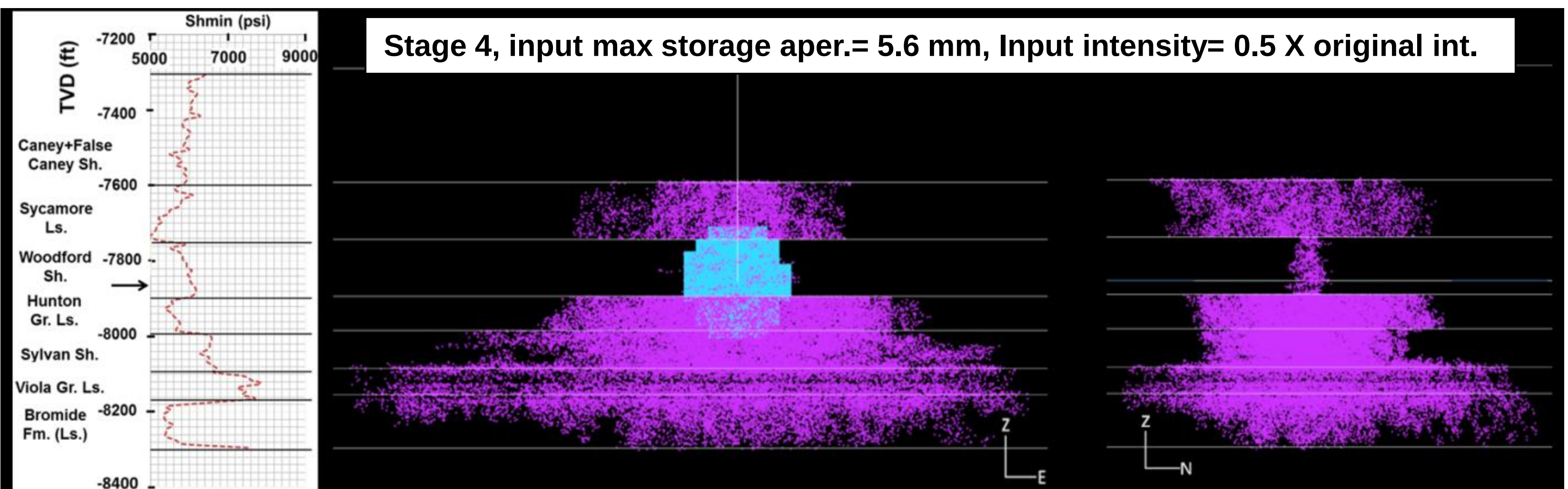
-HF stops at the top of Viola

No vertical exaggeration

Effect of halving natural fracture intensity and doubling max. fracture storage aperture (Stage 2)



Base case output efficiency: **1.4%**



At half intensity and twice storage aperture:

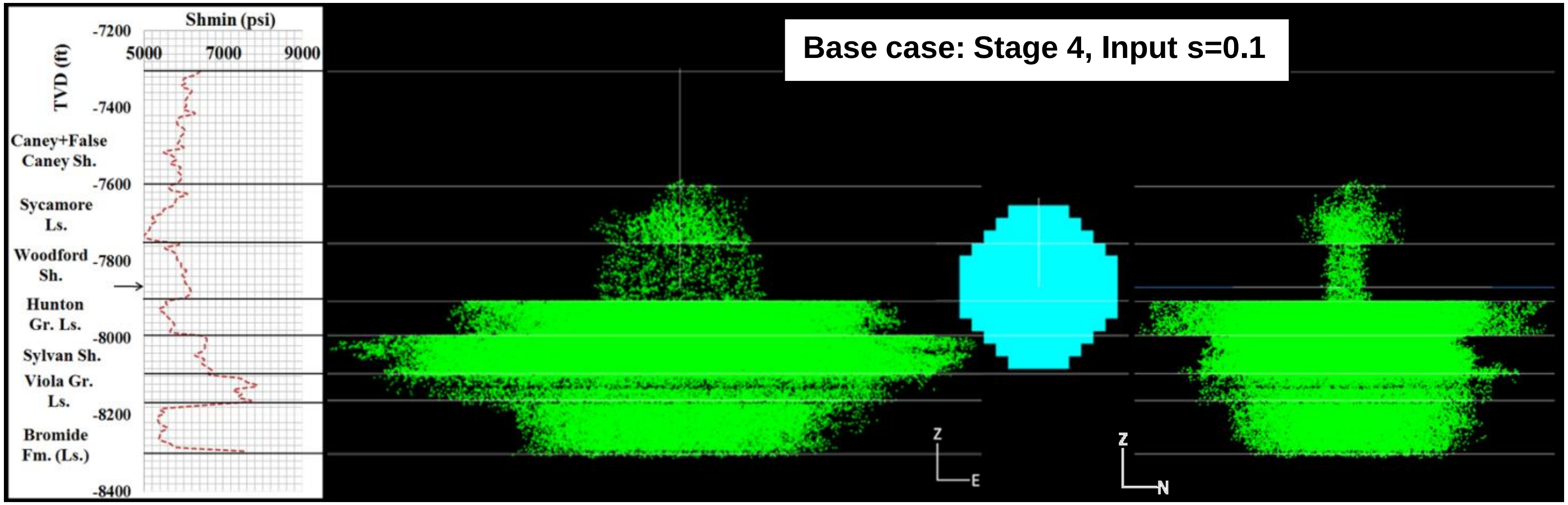
~44% percent reduction in Woodford stimulated volume

-Output efficiency: 1.4%, i.e., higher fluid efficiency cannot be achieved if all fractures are **allowed** to carry frac fluid.

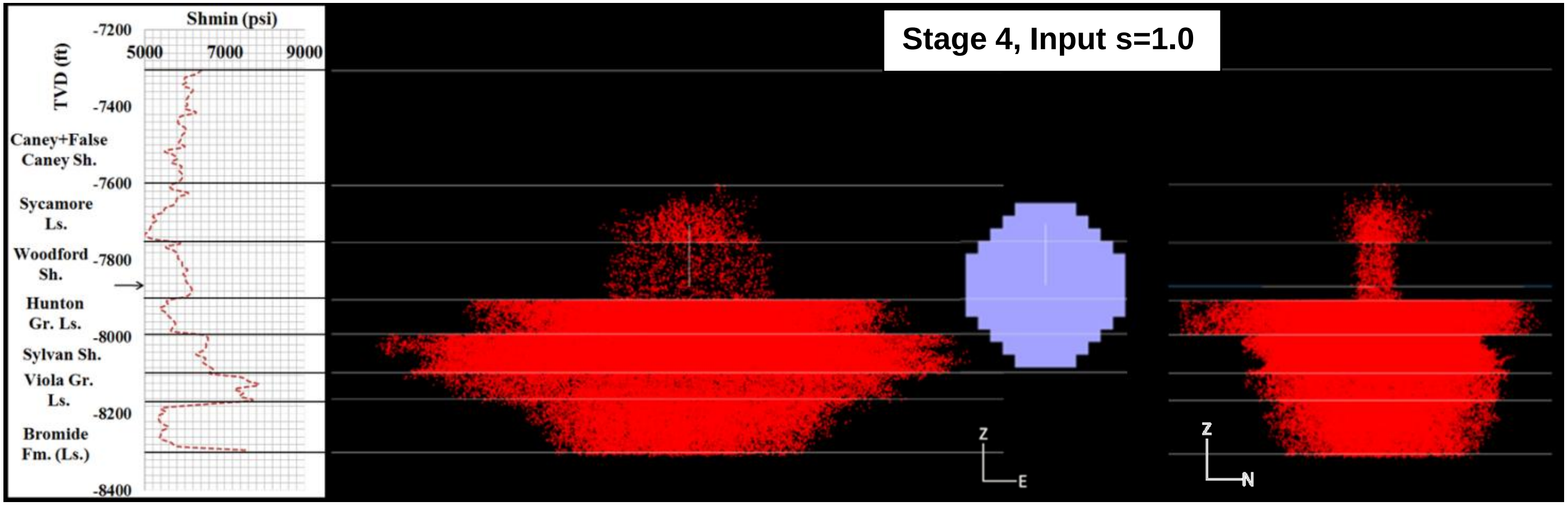
Note: Flow was allowed through non-dilatable fractures

No vertical exaggeration

Effect of increase in pressure drop slope magnitude



Output avg. aper.= 0.81 mm



At a higher pressure drop slope:

~**15%** decrease in overall stimulated volume.

-No change in Woodford stimulated volume.

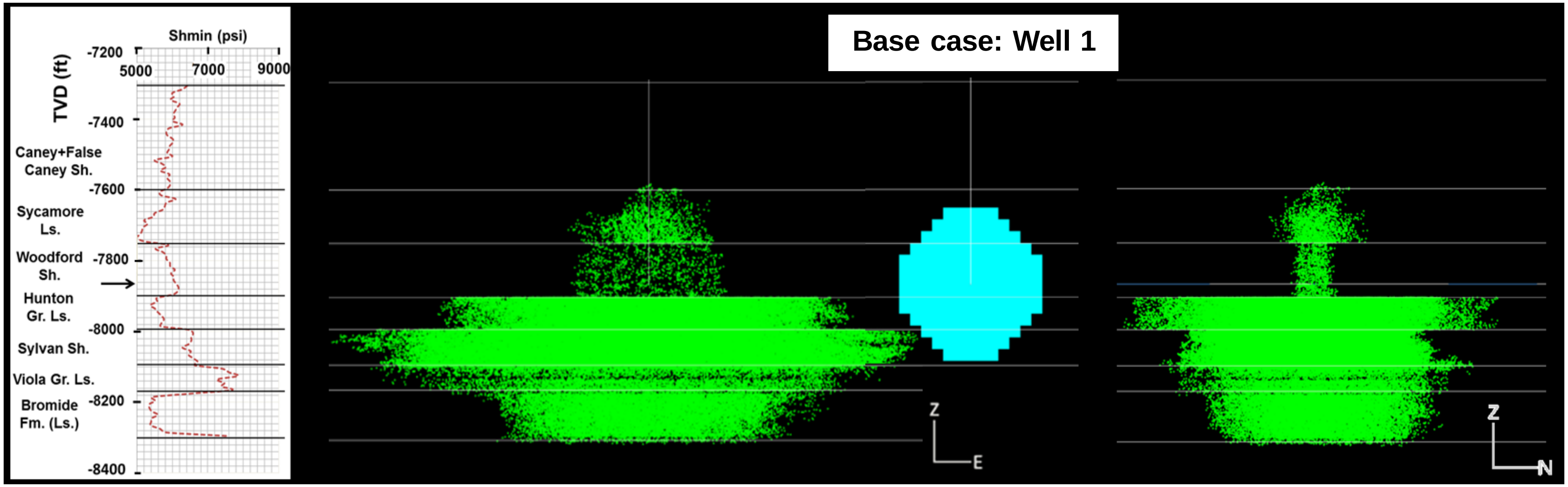
-Output average aper.= 0.97 mm.

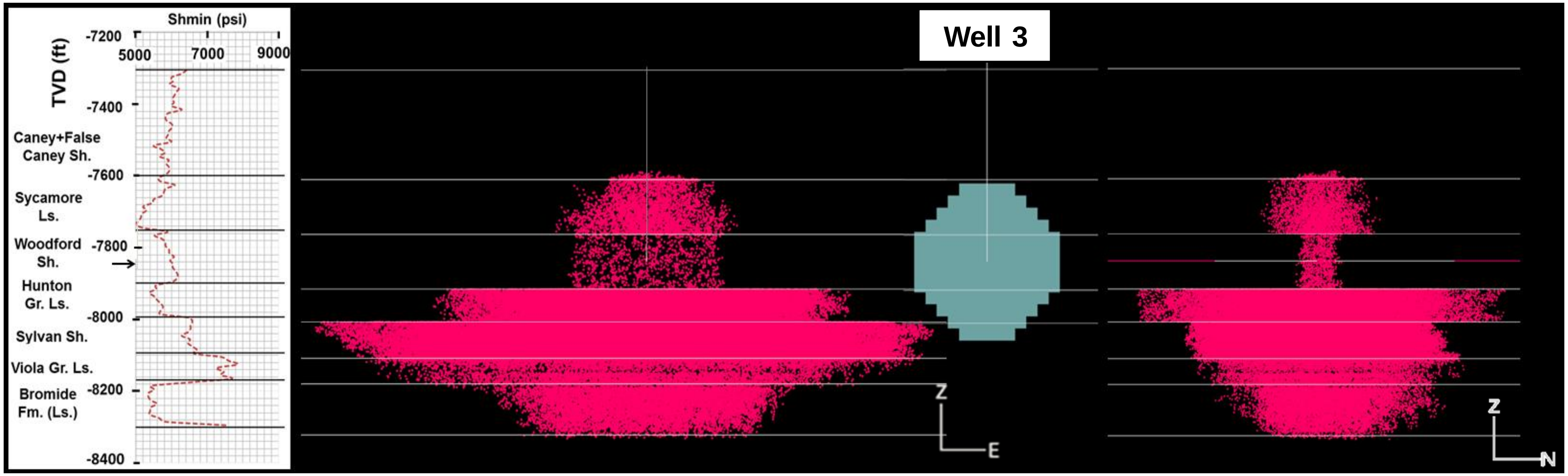
No vertical exaggeration

$$P_{pore} = (P_{pump} - \sigma 3_{max})\left(1 - \frac{s\,d}{d_{max}}\right) + \sigma 3_{max} + \rho\, g\, dh$$

s= pressure drop slope (FracMan™ Manual)

Effect of well location





No major change

No vertical exaggeration

Arrows near the depth scale indicate horizontal well depth

Conclusions

- Three stages geometries were matched. Viola Limestone has the highest and Woodford Shale has the lowest average permeabilities.
- Low fluid efficiency (< 2%) due to high natural fracture abundance was observed, i.e., natural fractures take almost (> 98%) of all the fracture fluid.
- It is possible to have high fluid efficiency if non-dilatable fractures do not allow fluid flow.
- Do not pump at a very high rate (net pressure), as it will result in out of target zone (Woodford Shale) stimulation.
- Place well higher up in the Woodford Shale as stimulation is likely to grow downward in the studied area.
- Strain accumulated in the previous stages can considerably affect the final stimulated geometry and reactivate more fractures in layers (formations) closer to the wellbore.
- High fluid pressure drop (e.g., by using high viscosity fluid) can reduce the stimulated volume and create wider storage apertures.

References

- Blanton, T.L., and J.E. Olson, 1999. Stress Magnitudes from Logs: Effects of Tectonic Strains and Temperature, SPE Paper 54653.

- FracMan^{TM} Manual (Workshop), 2014. Golder Associates.

- Neuhaus, C.W., 2011. Analysis of Surface and Downhole Microseismic Monitoring Coupled with Hydraulic Fracture Modeling in the Woodford Shale. Master's Thesis, Colorado School of Mines, Golden, CO.

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