Integrated Geosciences for Optimal Hydraulic Fracturing of Shale Reservoirs*

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Abstract

The integration of sequence stratigraphy and geomechanics characterization to evaluate shale reservoir fracability has been introduced by Slatt and Abousleiman (2011) and applied to characterize the Woodford Shale Formation (Tran et al., 2012). It is well known that some shale shrink and swell drastically when exposed to aqueous solutions. This chemically behavior of shale can significantly alter the formation characteristic and affect the hydraulic fracturing efficiency. In this work, the shale formation geochemical properties such as Cation Exchange Capacity (CEC) and pore fluid salinity are incorporated into the poroelastic Mandel's problem to better optimize the hydraulic fracture job.

The Mandel's problem has been used by geomechanicians to describe the responses of reservoir during steam flooding and production. Regarding hydraulic fracturing in shale, the Mandel's problem mimics a shale formation section formed by two often closely spaced parallel natural fractures that reopen and propagate during hydraulic fracturing. In this work, the solutions are used to investigate the effects of fracturing fluid chemistry and formation clay content on the fracture deformation and the stresses distributions inside the shale formation.

The analyses show that the presence of reactive clay can induce additional fracturing fluid loss into the formation and create a tensile damage zone near the fracture surface. In particular, shale with higher CEC values will result in more severe fluid loss and a larger the damage zone near the fracture face. The damaged formation shall become weaker and deform more easily under application of hydraulic pressure, leading to a wider fracture aperture and a shorter fracture length. Similarly, a large amount of fluid loss will significantly reduce the pressure acting on the fracture wall necessary for the fracture propagation. Thus, the results explain why intervals with high content of reactive clay such as smectite are often observed to be more ductile than the lower and less reactive clay intervals. The results also show that a fracturing fluid with higher salinity than the native pore fluid can reduce the fracturing fluid loss and, thus, works for the advantages of the fracturing job.

The outcomes of this work will allow, for the first time, the integration of shale geochemical properties into the aforementioned geological-geomechanics framework for shale reservoirs fracability evaluation and hydraulic fracturing optimization.

Selected References

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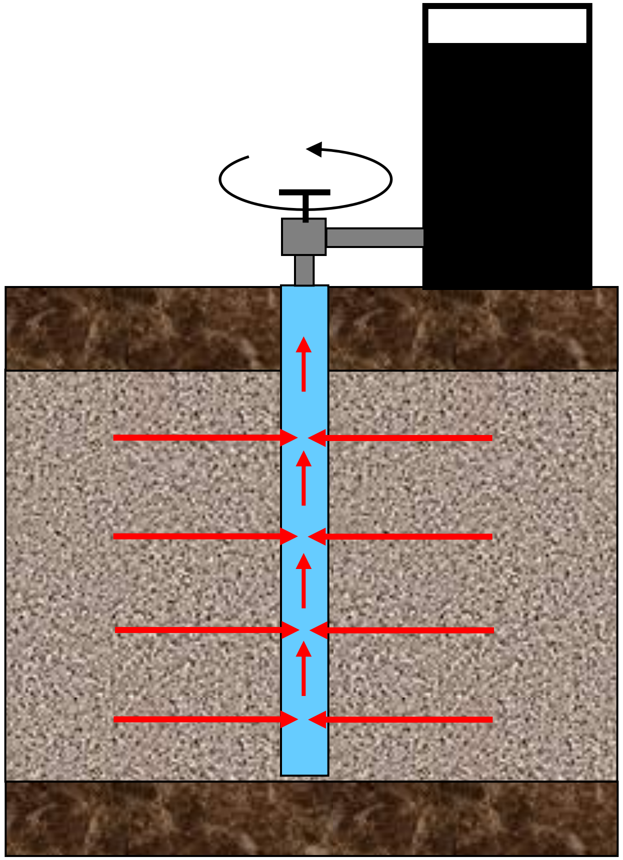
by

Minh H. Tran & Younane N. Abousleiman

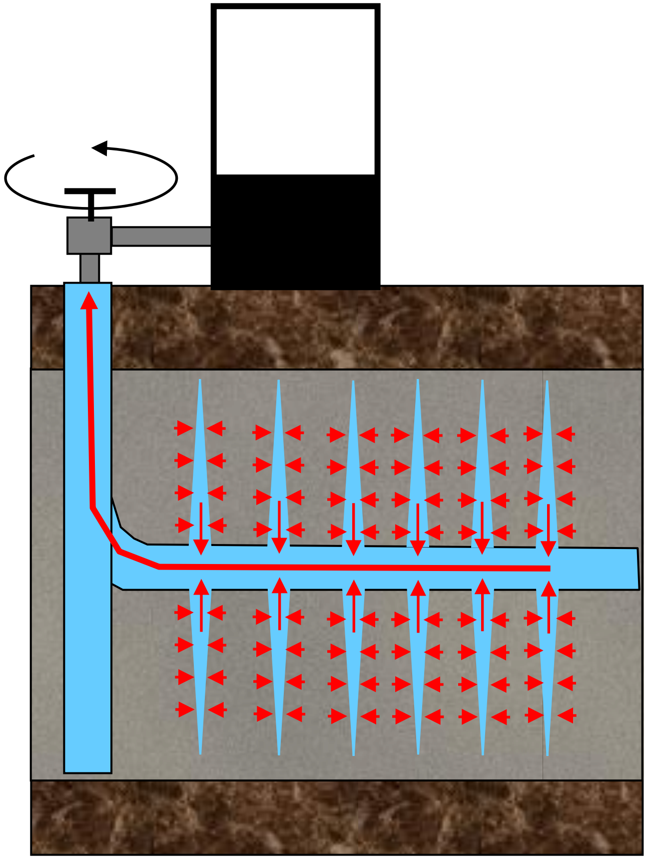
May 20, 2013

Pittsburgh, Pennsylvania, USA

Hydraulic Fracturing Is A Must



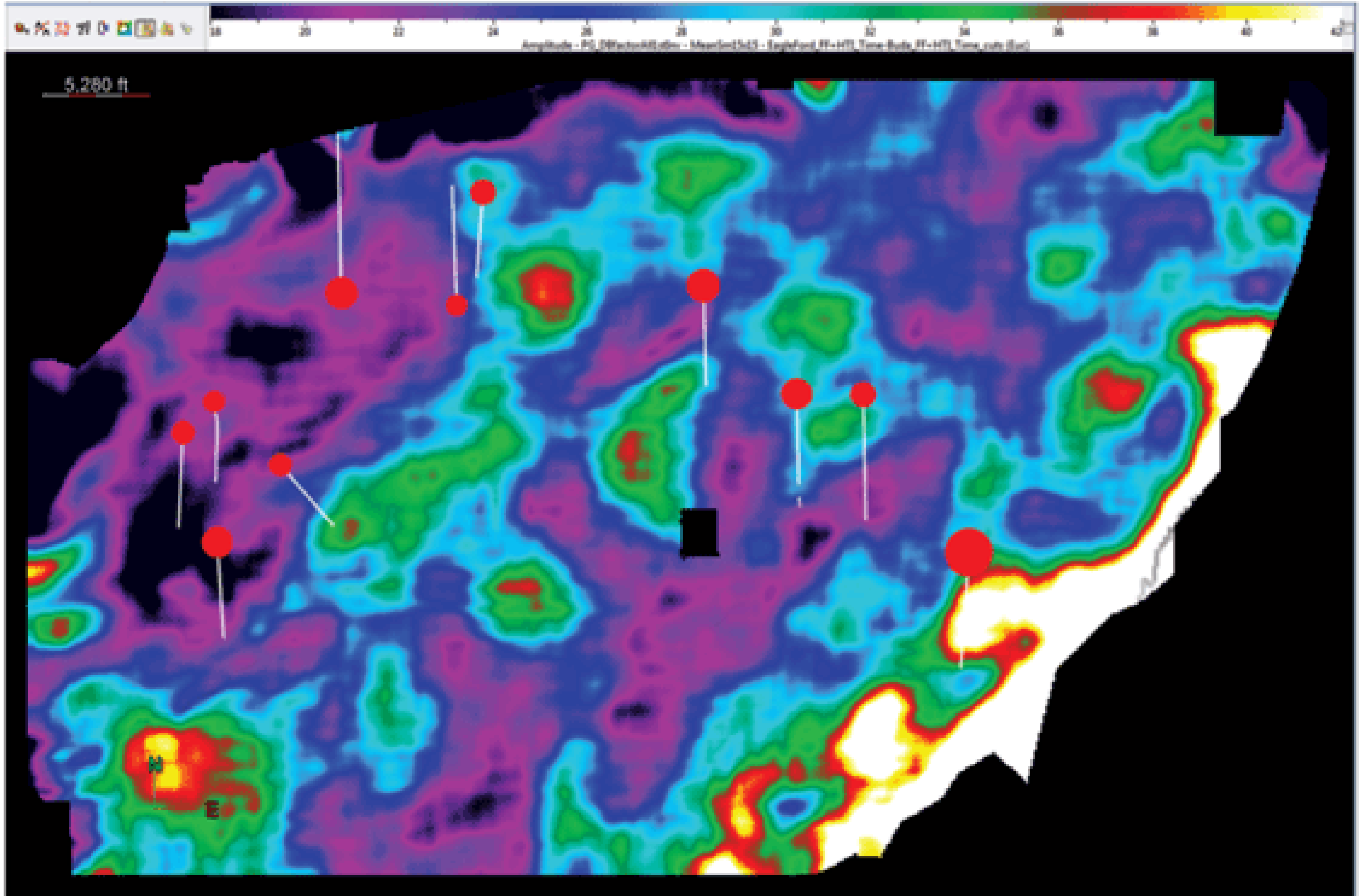
Conventional reservoirs
(sandstone, limestone…)



Unconventional reservoirs
(gas shales, oil shales)

Current Shale Plays Evaluation Technique

TOC & "BRITTLENESS INDEX" have been used key factors



Brittleness index map of Eagle Ford from seismic attribute

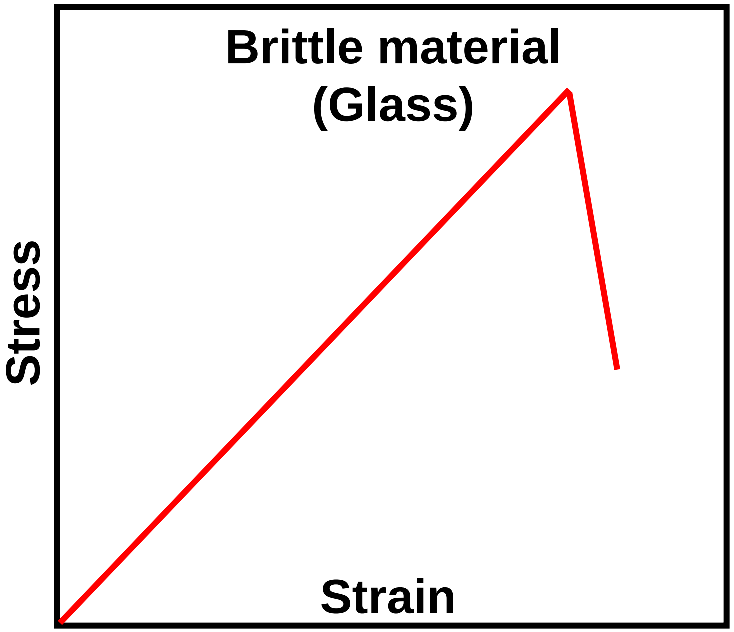
Source: Usher (2012, American Oil & Gas Reporter)

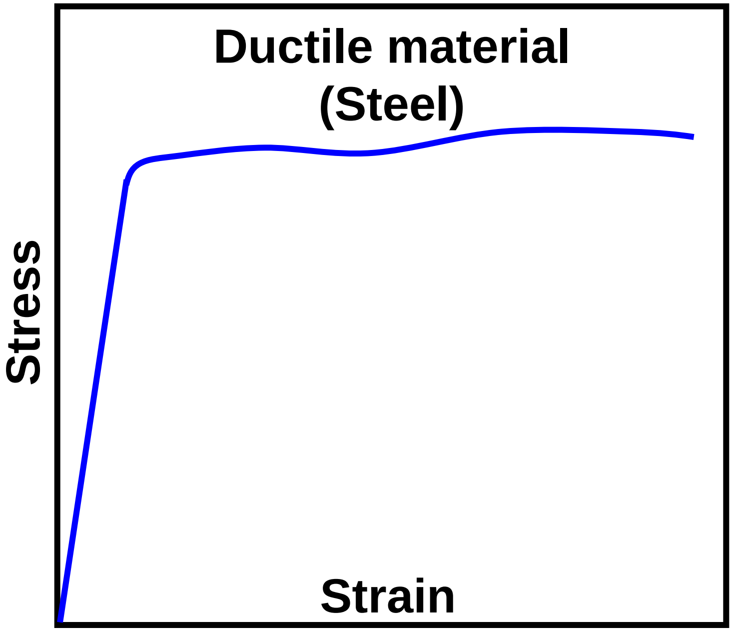
Shale Brittleness Index

Wang & Gale (2009): $$BI = \frac{\text{Quartz} + \text{Dolomite}}{\text{Quartz} + \text{Dolomite} + \text{Calcite} + \text{Clays} + \text{TOC}}$$

Rickman et al. (2008): $$BI = 0.5\left(\frac{\text{Young's Modulus} - 1}{8 - 1} + \frac{\text{Poisson's Ratio} - 0.1}{0.3 - 0.1}\right)$$

How are these related to what we know about brittle and ductile?



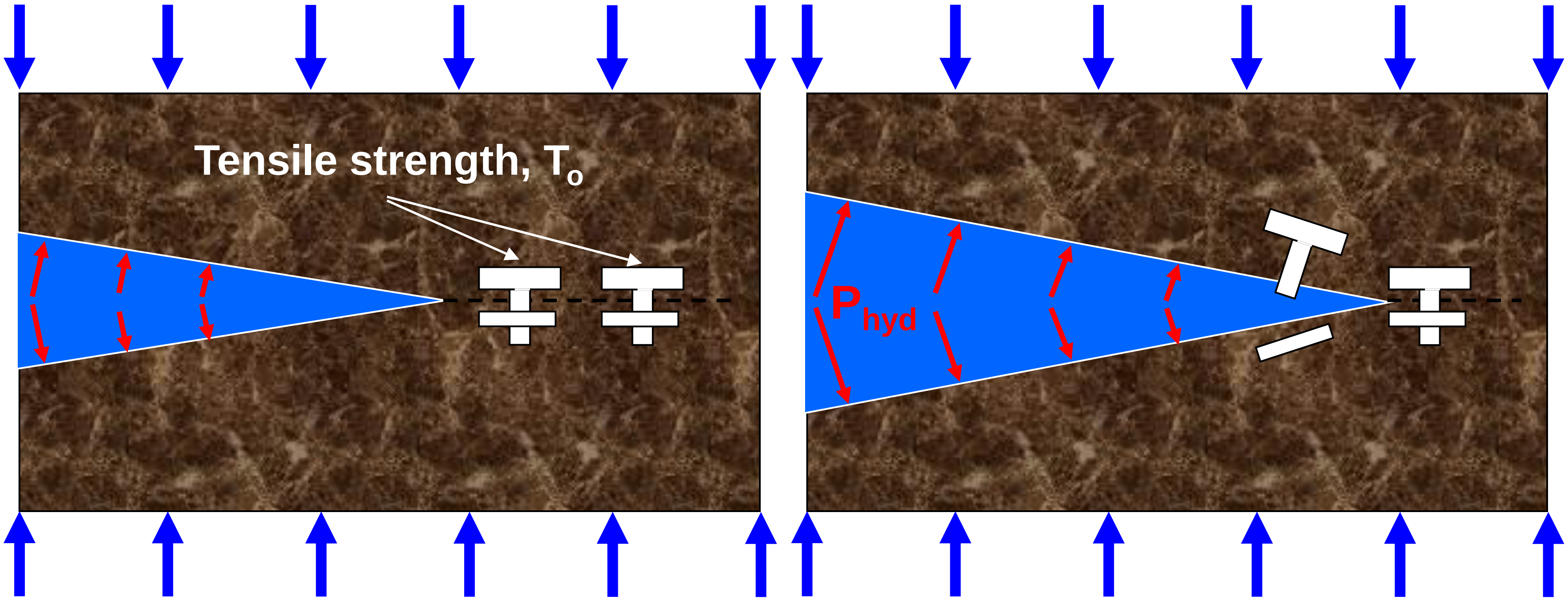


Regarding Fracturing Efficiency

Brittle: Easy to open + long fracture + easy to keep open

Ductile: Hard to open + short fracture + hard to keep open

Factors Controlling Fracture Opening



We can ignore tensile strength

$T_o << S_h$

$$F.G. = \frac{S_h + T_o}{Depth}$$

$$S_h = \frac{E_1}{E_3}\frac{v_3}{1-v_1}\left(S_v - \alpha_3 P\right) + \alpha_1 P$$

See: Tran et al. (AAPG 2012)

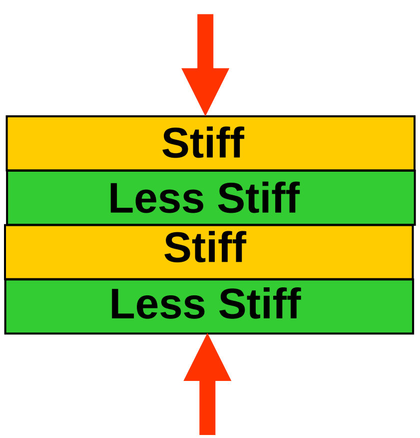
What Do We Know About Shale?

Shale is anisotropic!

Anisotropic properties of Woodford shale (Abousleiman et al., 2007)

Depth (m)	E_1 (GPa)	E_3 (GPa)	G_1 (GPa)	G_3 (GPa)	ν_3	α_1	α_3
39.93	17.93	10.49	8.10	5.17	0.29	0.69	0.73
47.24	21.63	12.24	9.76	6.52	0.24	0.69	0.75
50.60	19.51	10.87	8.78	5.32	0.26	0.70	0.76
53.34	23.50	13.40	10.25	5.62	0.23	0.65	0.73
56.69	16.47	9.25	7.46	4.94	0.29	0.72	0.76

$E_1/E_3 \sim 2$ **$G_1/G_3 \sim 2$**



With:

E: Young's modulus

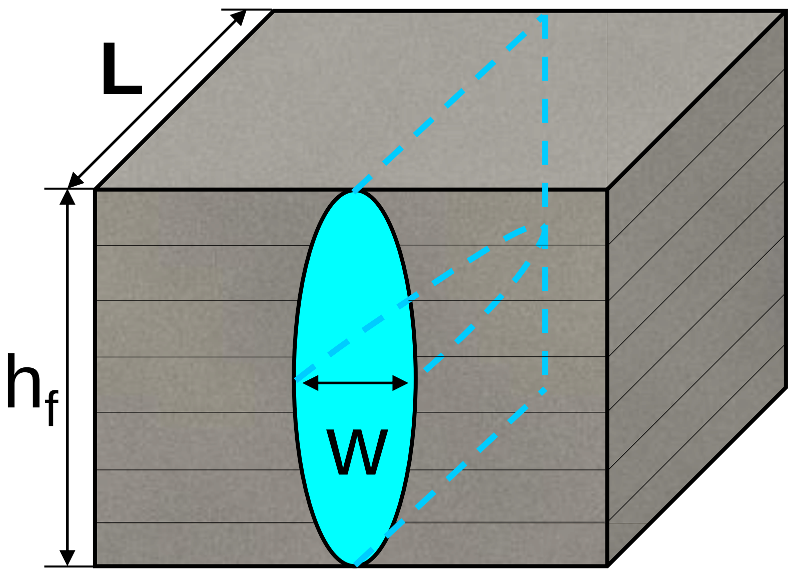
G: Shear modulus

ν: Poisson's ratio

α: Biot's pore pressure coefficient

Factors Controlling Fracture Length

$$L = 0.68\left(\frac{E_1 Q^3}{\mu(1-\nu_1^2)h_f^4}\right)^{1/5} t^{4/5}$$



With

L: Fracture length

μ: Fracturing fluid viscosity

h_f: Fracture height

Q: Pumping rate

t: Pumping time

See: Tran et al. (AAPG 2012)

Summary of Geomechanics Parameters Controlling Shale "Brittleness"

$$S_h = \frac{E_1}{E_3}\frac{v_3}{1-v_1}S_v + \left(\alpha_1 - \frac{E_1}{E_3}\frac{v_3}{1-v_1}\alpha_3\right)P$$

How easy it is to open the fracture

$$L = 0.68\left(\frac{E_1 Q^3}{\mu(1-v_1^2)h_f^4}\right)^{1/5} t^{4/5}$$

How easy it is to produce long fracture

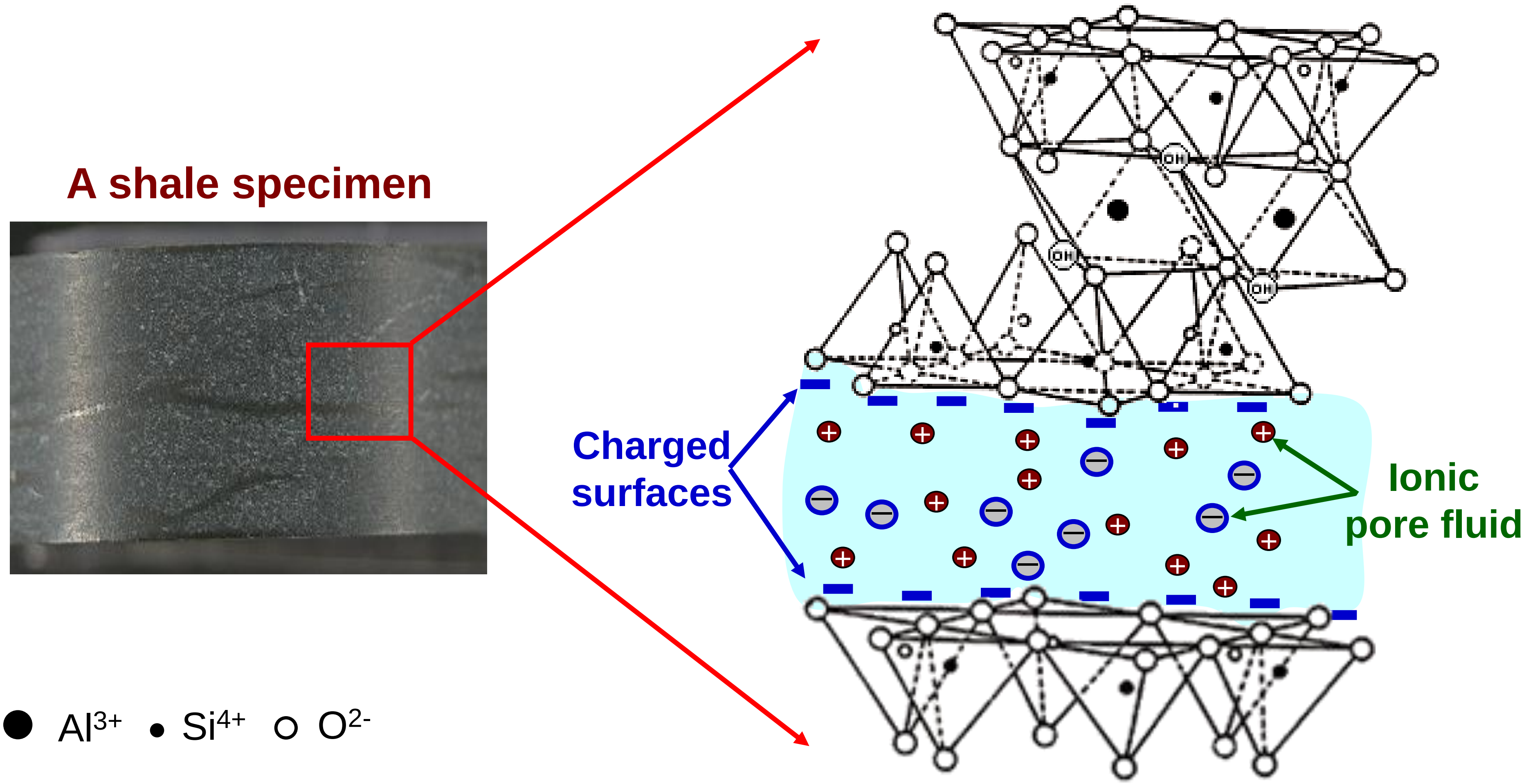
Anything Else We Know About Shale?

Some shale can react strongly with some fluids!

4% $CaCl_2$

16% $CaCl_2$

A Closer Look at Shale

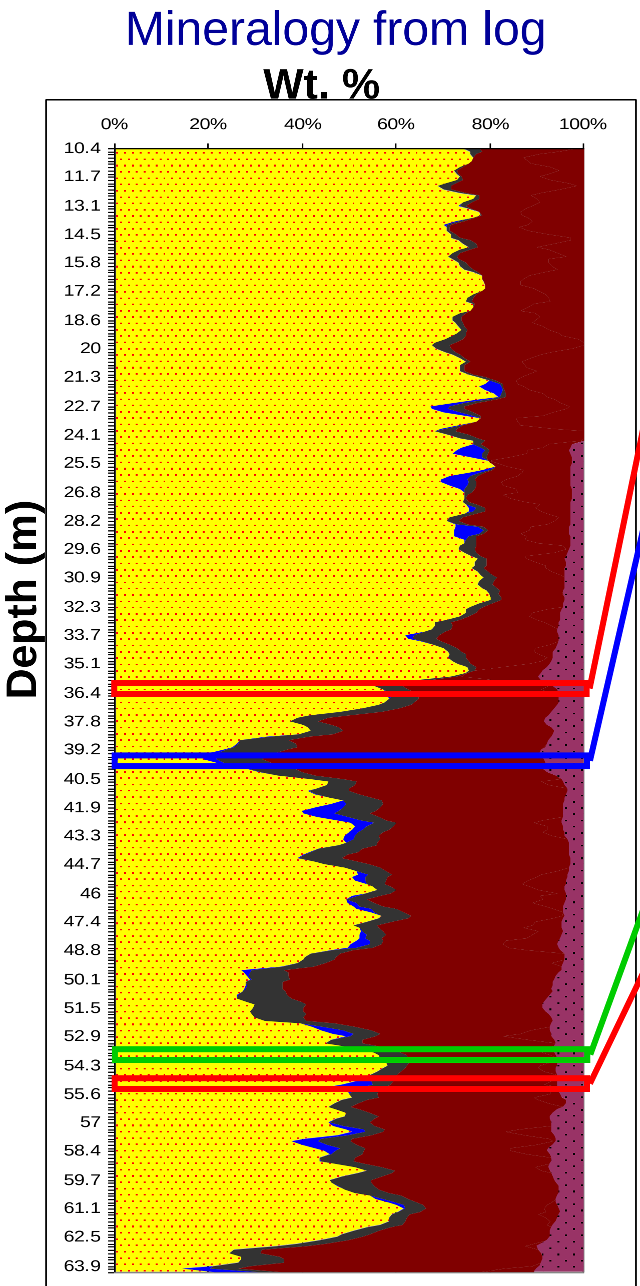


● Al^{3+} • Si^{4+} ○ O^{2-}

Pore fluid dissolved anion (Cl^-, etc.)

Pore fluid dissolved cation (Na^+, K^+, etc.)

Variation of Woodford GeoChemical Properties



Depth (m)	Sum Non-Clay	Sum Clay	CEC (meq/100g)
33.7	62	20	9
36.7	82	5	4
36.9	94	2	3
39.9	54	30	14
41.3	62	25	8
42.8	54	30	9
47.0	54	32	9
47.2	55	28	8
50.6	51	31	13
53.4	52	36	11
54.7	67	18	6
56.7	49	37	9
57.9	46	43	10
61.2	59	26	9
64.2	42	43	10

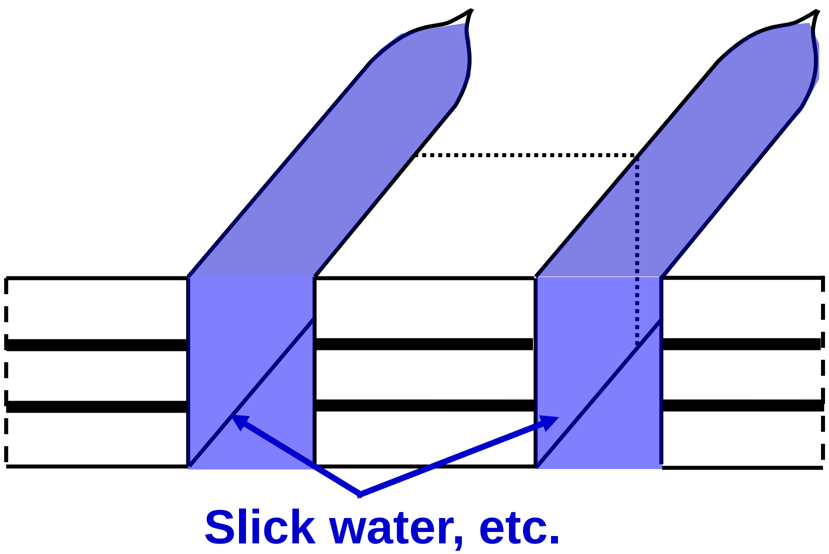
Effects of Frack Fluid & Shale Chemistry

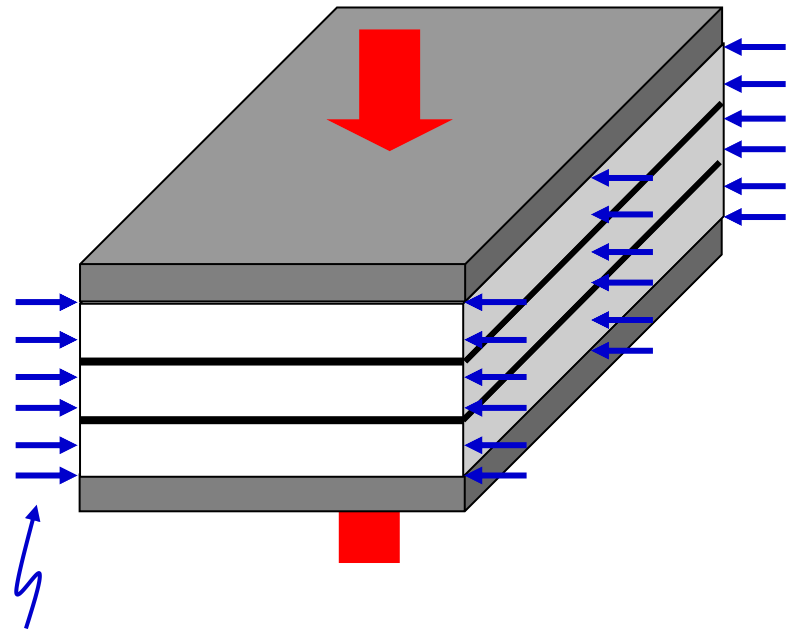
Depth: 2000 m

Overburden: 41 MPa

S_h: 25 MPa

Virgin pore pressure: 18 MPa





Fracturing fluid:

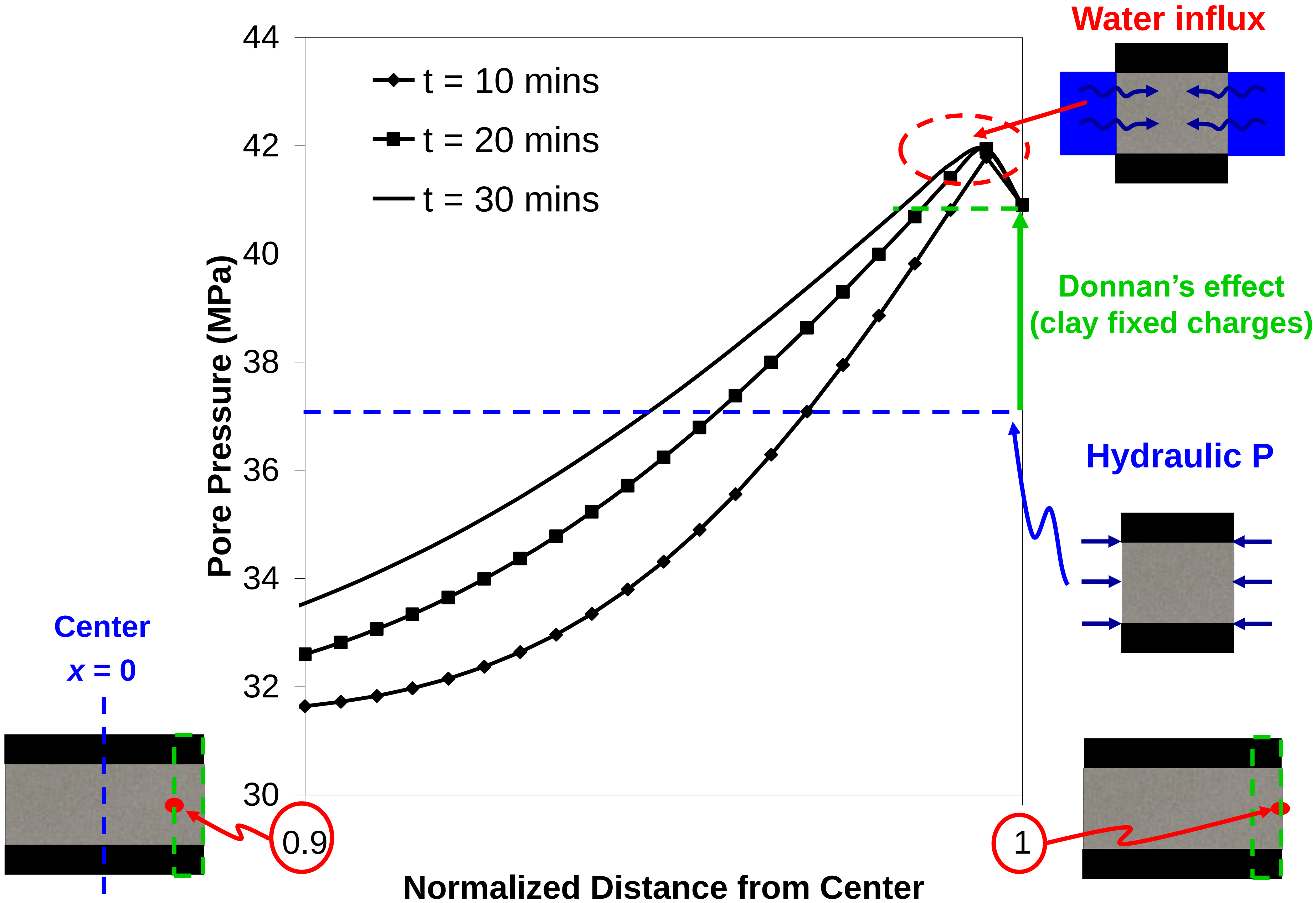
- **2.5% NaCl (or a_{frack} = 0.95)**
- **P = 37 MPa**

Woodford Shale Properties

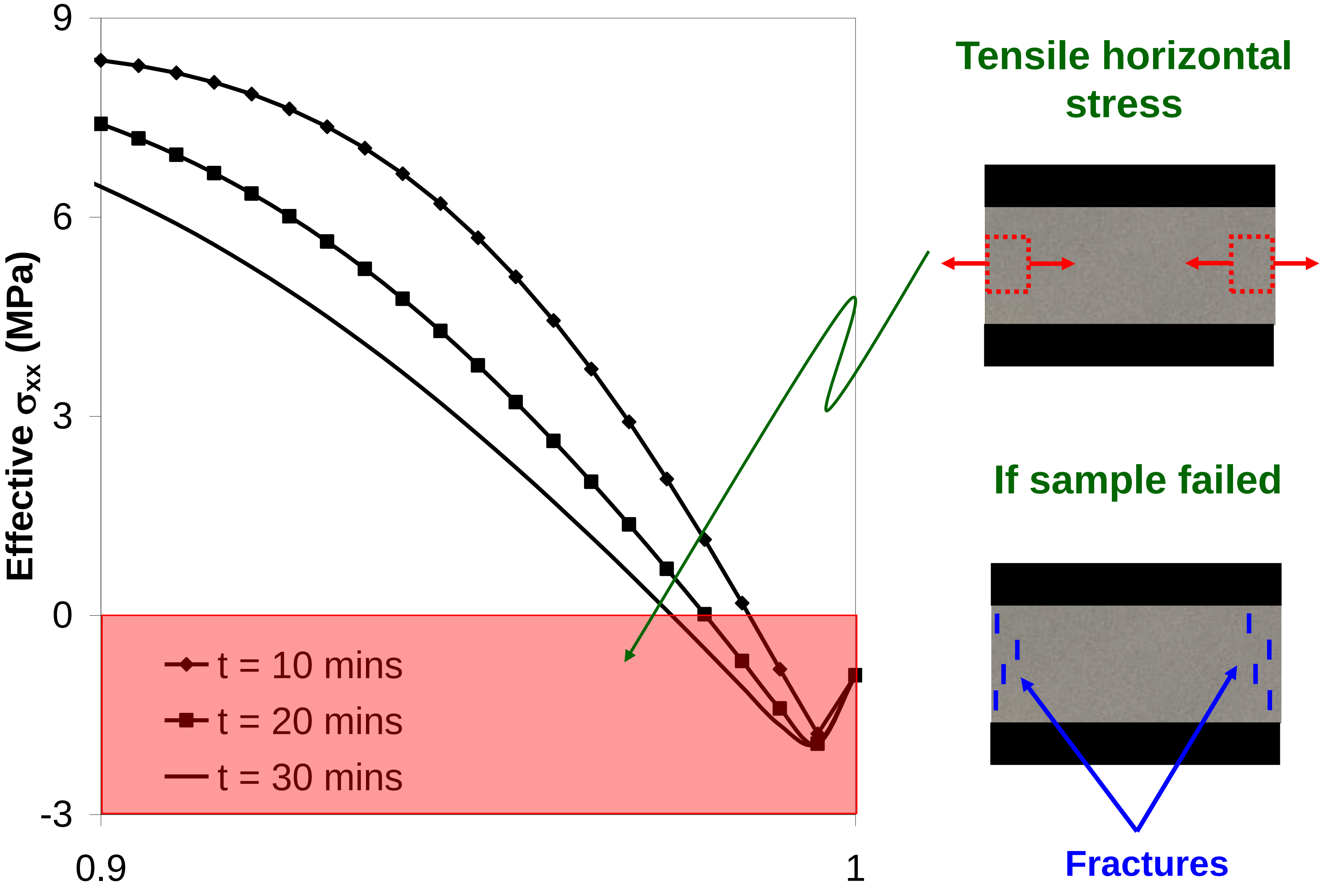
See: Tran & Abousleiman (JAM, 2013), Tran & Abousleiman (MRC, 2013)

Parameters	Values	Notes
Young's modulus, E_1 (GPa)	7.4	Calculated with $E_1/E_3 = 1.75$ from dynamic measurements
Young's modulus, E_3 (GPa)	4.2	Quasi-static measurements (Abousleiman et al., 2007)
Poisson's ratio, ν_1	0.13	Calculated with $\nu_1/\nu_3 = 0.42$
Poisson's ratio, ν_3	0.30	Quasi-static measurements (Abousleiman et al., 2007)
Biot's pore pressure coef., α_1	0.85	Calculated
Biot's pore pressure coef., α_3	0.88	Calculated
Biot's modulus (GPa)	12.0	Calculated
D_{eff} of Na^+ (m^2/s)	1.60×10^{-10}	$D^{Na+} = 1.33 \times 10^{-9}$, $\tau=1$
D_{eff} of Cl^- (m^2/s)	2.44×10^{-10}	$D^{Cl-} = 2.03 \times 10^{-9}$, $\tau=1$
Porosity	0.15	From Hg-injection
Permeability (nD)	200	From pulse decay
Membrane efficiency	0.2	Assume
CEC (meq./100 gr of dry clay)	10	Measured CEC of Woodford shale: 5-15 meq./100 gr clay
Native activity	0.89	Measured Woodford activity: 0.87-0.89
Matrix density (g/cc)	2.3	From XRD mineralogy and porosity

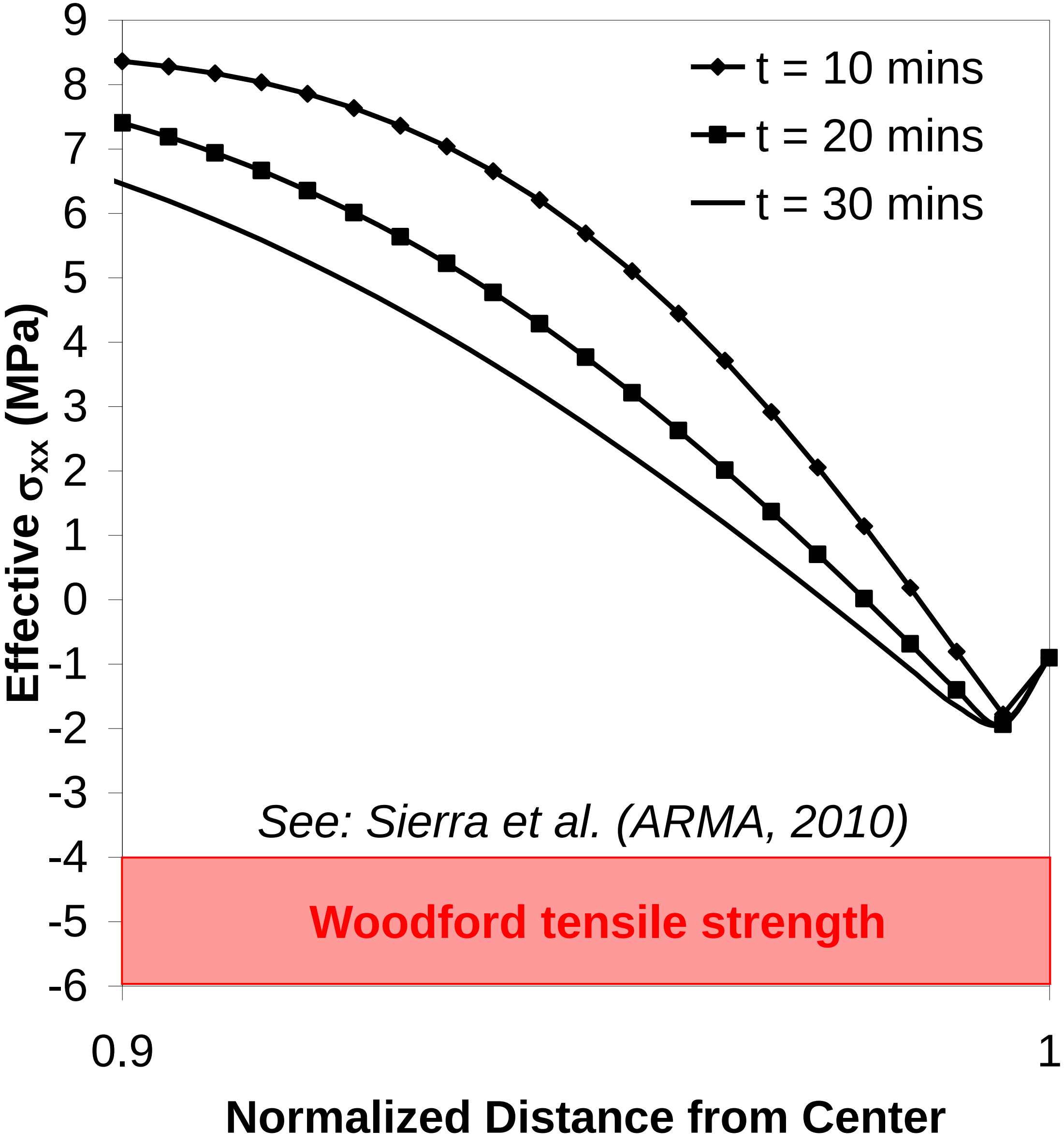
Pore Pressure Distribution



Effective Horizontal Stress Distribution

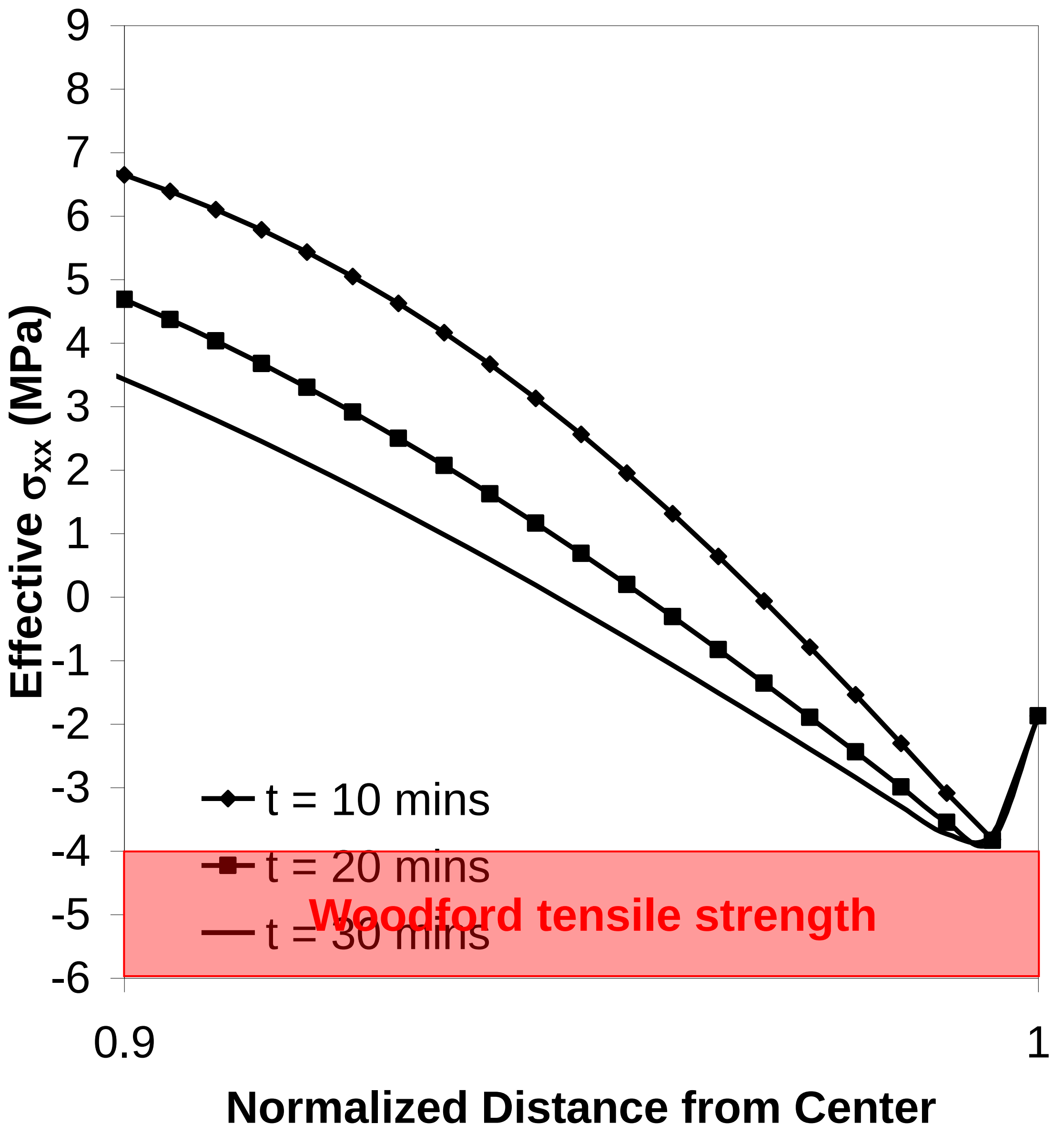


Will The Formation Damaged?



No!

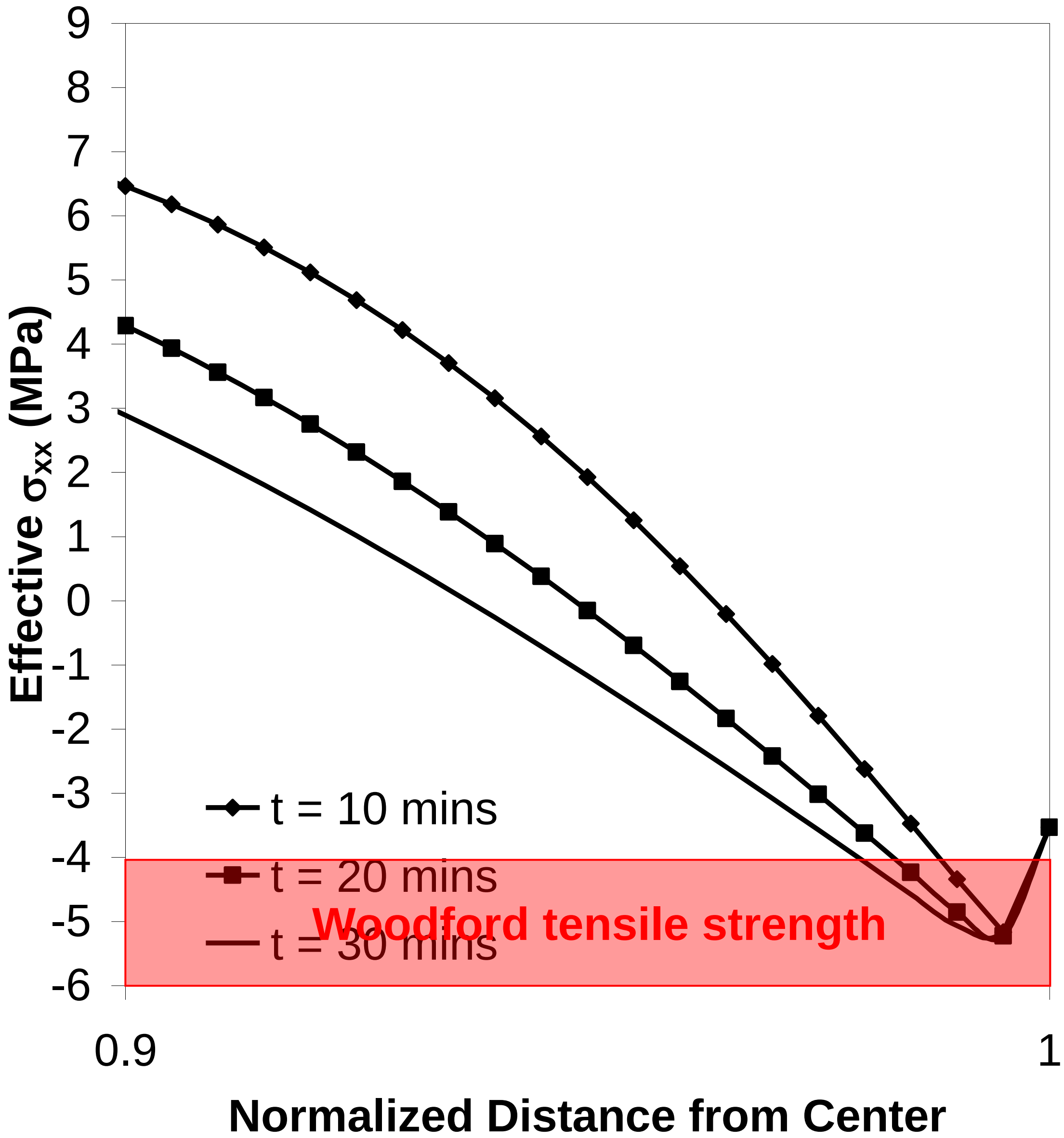
CEC = 10, a_{frack} = 0.98 (tap water mix)



No!

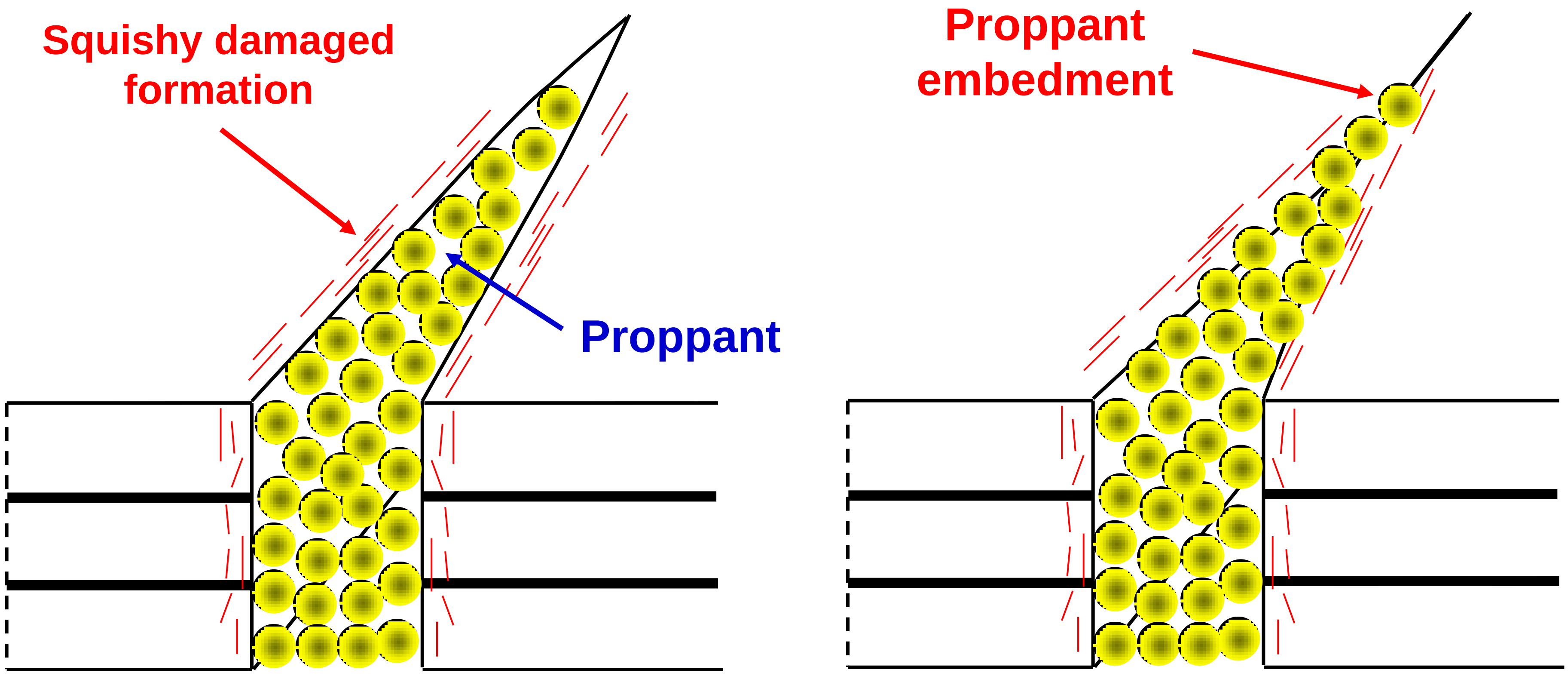
(about to)

CEC = 15 (more reactive), a_{frack} = 0.98



Damage!

Effects of Induced Tensile Damages on Fracturing



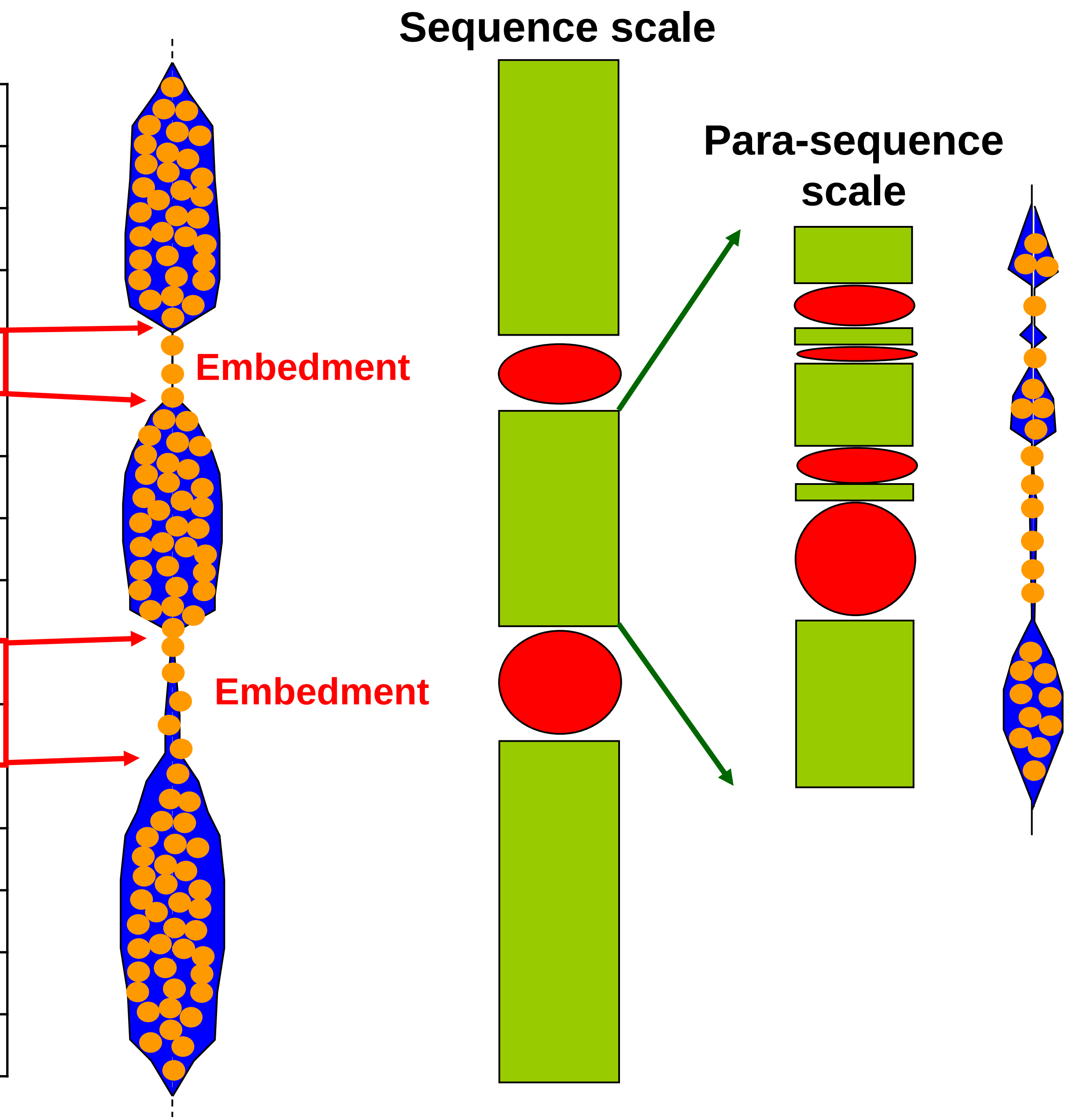
Damaged formation is weaken → deform more

Larger proppant embedment → fracture closure

Porochemistry + Poromechanics for Brittleness

Woodford shale CEC

Depth (m)	CEC (meq/100g)
33.7	9
36.7	4
36.9	3
39.9	14
41.3	8
42.8	9
47.0	9
47.2	8
50.6	13
53.4	11
54.7	6
56.7	9
57.9	10
61.2	9
64.2	10



Why Integrated Geosciences?

With chemistry + geomechanics we know:

$$BI = \frac{\text{Quartz} + \text{Dolomite}}{\text{Quartz} + \text{Dolomite} + \text{Clays} + \text{TOC}}$$

Type of clays, CEC values, pore fluid & fracking fluid compositions are all important!!!!

With geomechanics we know:

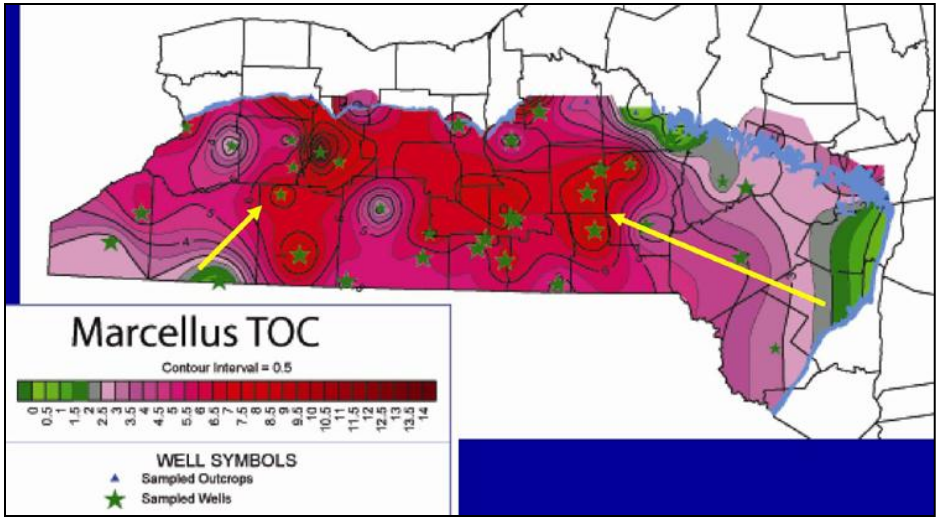
$$S_h = \frac{E_1}{E_3}\frac{v_3}{1-v_1}S_v + \left(\alpha_1 - \frac{E_1}{E_3}\frac{v_3}{1-v_1}\alpha_3\right)P \qquad L = 0.68\left(\frac{E_1 Q^3}{\mu(1-v_1^2)h_f^4}\right)^{1/5} t^{4/5}$$

These groups are important for “brittleness” evaluation.

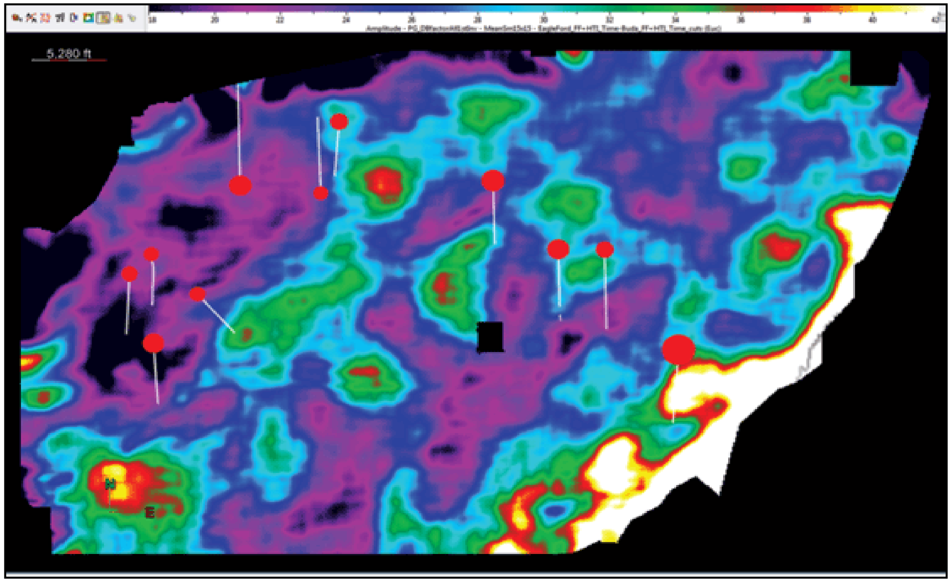
It also takes into account shale anisotropy

The Message

TOC, oil, gas are what we are truly after & cannot change it!



Brittleness may be improved with proper engineer practice!!!



Conclusions

- Integrated geosciences brings a more complete picture of various factors influencing shale fracturing efficiency:
  - Shale anisotropy
  - Shale reactivity
  - Fracking fluid chemistry
- Appropriate engineering practice can help to improve fracking efficiency.

Acknowledgements

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