Key Parameters for Liquid-Rich Unconventional Plays: Case Studies from North America*

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Abstract

There is a considerable interest in understanding the production of liquids from shales with the discovery and exploitation of liquid-producing regions in numerous unconventional plays including the Eagle Ford, Bakken, Niobrara, Utica/Point Pleasant, Mississippi Lime, and others. It is important to understand how liquids are produced from ultra-low-permeability rocks so that production rates and recovery could be optimized.

The geological and engineering considerations in optimizing liquid recoveries from “shales” are complex. A comprehensive study of fluid production from shales should include lithology and mineralogy, natural fractures and faults, petrophysics, micro-imaging, geochemistry including TOC, thermal maturity, and kerogen type, production declines, GOR and other phase changes, recovery factors, fluid properties, relative permeabilities, pressure dependence, and completion practices.

Past assumptions about “shales” have been that they are good seals over conventional reservoirs, as well as source rocks, where the TOC and thermal maturity are conducive. As a seal, the implication is that hydrocarbons are prevented from flowing through them. And yet, as a source rock, we assume that somehow the generated oil is able to escape and migrate into the conventional reservoir. Do source rock systems work only because they have ample geologic time over which to enable oil escape and migration?

Production results in these plays are showing several anomalous characteristics that could overturn previous concepts about what is and is not possible in nano-permeability systems. Previous geologic models for sediment accumulation, water depth, effects of currents, and biologic activity are proving to be over-simplified and in many cases wrong. Mud-rock heterogeneity is a much bigger factor than previously thought.

The Energy & Geoscience Institute at the University of Utah has been studying these liquids-rich systems in depth for the past 2-3 years. We have been using micro-imaging technologies including SEM, QEMScan, and FIB, on core and outcrop samples, ranging upscale to field, regional, and basin-scale characterization and modeling. Several examples of liquids-rich systems will be featured in a case-study examination of controlling parameters, focusing especially on the Bakken, Eagle Ford, and Niobrara.

Also incorporated into this study are existing pore- and pore-throat-size classification schemes, and porosity-type classification systems. Different porosity types may act very differently with respect to effective permeability. Simply visualizing these geometries is a useful step. Hopefully, it will lead to a fundamental improvement in our understanding of fluid flow through nano-pores and pore throats in the matrix, and will help significantly in developing unconventional "shale" reservoirs.

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EGI Energy & Geoscience Institute
AT THE UNIVERSITY OF UTAH

Key Parameters for Liquid-Rich Unconventional Plays: Case Studies from North America

Tom Anderson | Tuesday, 5 November 2013

AAPG Geosciences Technology Workshop
Vancouver, BC

egi.utah.edu | *The Science To Find Energy*

North American shale plays
(as of May 2011)

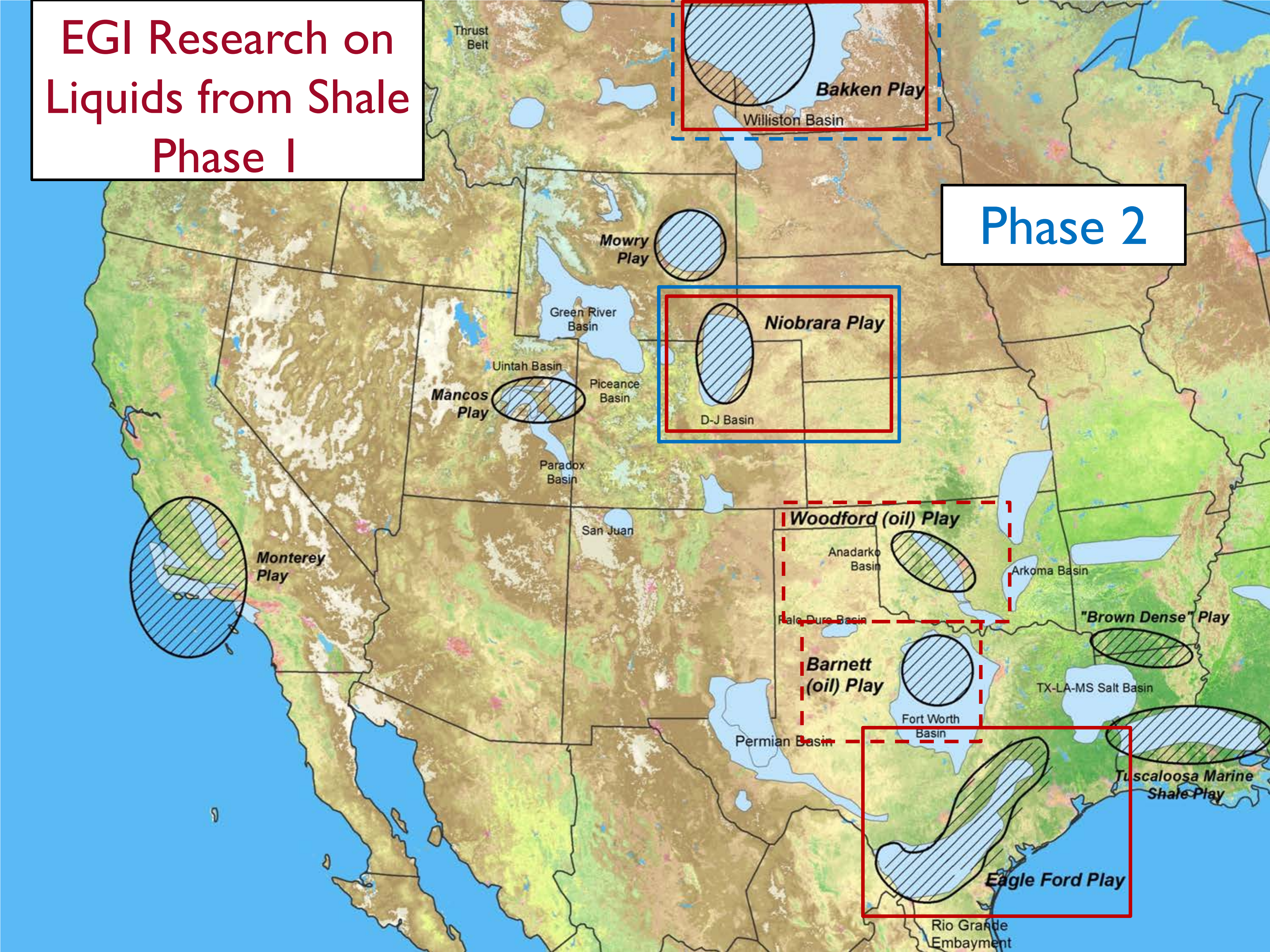
Every shale is different –

- *We can't just use observations, experience, and practices from one shale to understand the next play*
- *But, there are several different geologic settings and characteristics that can succeed as liquids-rich production*

"Shale List Grows – Wet Is In"*

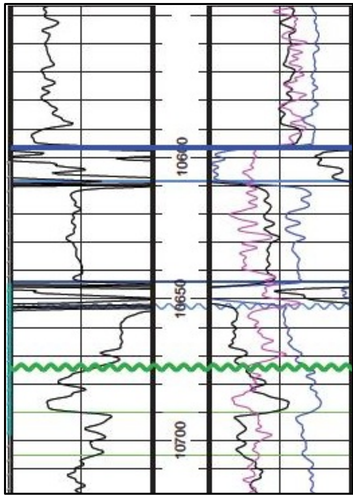
- **Avalon Shale**
- **Bakken**
- **Barnett Combo**
- **Bone Spring**
- **Cana Woodford**
- **Cardium**
- **Cleveland**
- **Eagle Ford**
- **Exshaw**
- **Granite Wash**
- **Marcellus**
- **Mississippi Lime**
- **Monterey**
- **Montney**
- **Niobrara**
- **Tonkawa**
- **Tuscaloosa Marine Shale**
- **Utica-Point Pleasant**
- **Viking**
- **Wolfcamp-Wolfberry-Wolfbone**
- **Woodford**

Durham, Louise, AAPG Explorer July 2012

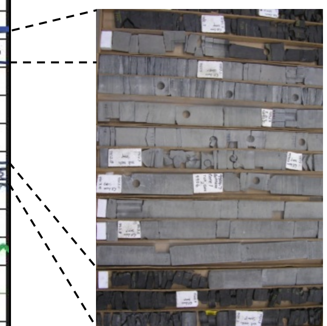


EGI Research on Liquids from Shale Phase I
Phase 2
Thrust Belt
Bakken Play
Williston Basin
Mowry Play
Niobrara Play
Green River Basin
Uintah Basin
Piceance Basin
Mancos Play
D-J Basin
Paradox Basin
San Juan
Woodford (oil) Play
Anadarko Basin
Arkoma Basin
Palo Duro Basin
"Brown Dense" Play
Monterey Play
Barnett (oil) Play
Fort Worth Basin
TX-LA-MS Salt Basin
Permian Basin
Tuscaloosa Marine Shale Play
Eagle Ford Play
Rio Grande Embayment

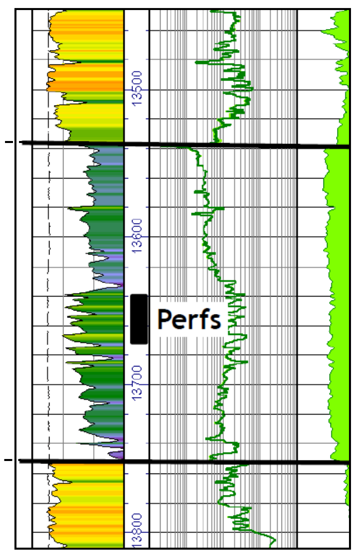
Conceptual Models Comparison

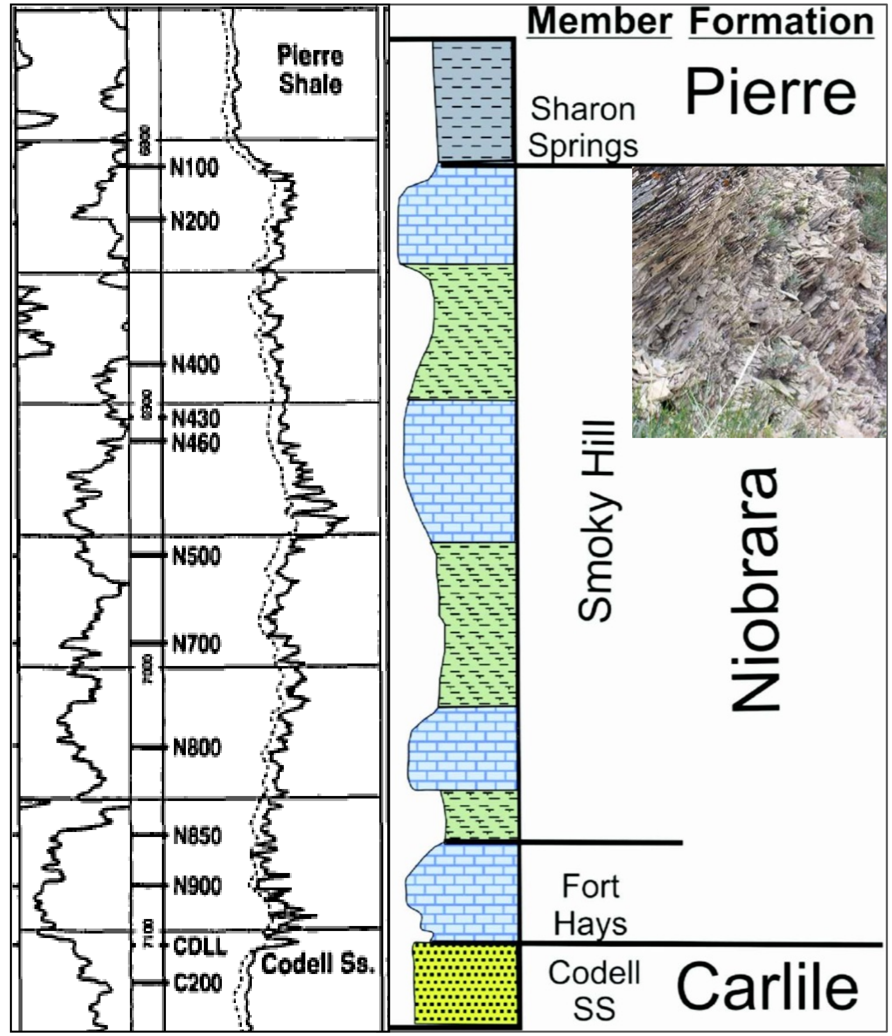


Bakken/
Three Forks



Eagle Ford





Source: *Pioneer Natural Resources, 2011, "Eagle Ford Shale Field Tour"*

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What Makes a Shale Play Good?

- Thickness
- Porosity
- Mineralogy (brittleness)
- Organic Richness
- Thermal Maturity
- Pressure

- Pore Pressure
- Gas in Place
- TOC
- Maturation
- Depth of Burial
- Natural Fractures
- Shale Thickness
- Reservoir Pressure
- porosity
- permeability
- texture
- Structures

- Total organic carbon (TOC)
- Maturation: "gas" window - 1.1 to 1.4 Ro.
- Low hydrogen content - gas prone.
- Moderate clay content - less than 40%.
- Thickness - greater than 100 ft.
- Good gas content - greater than 100 scf/ton.
- Brittle and contain hydraulic fractures.

PARAMETER
Source Rock Quality
Source Maturity
Gas Quality
Structural Complexity
Timing of Burial/uplift
Clay content/ brittle index
Presence of water-filled aquifers
Geomechanics (stress regime)
Pore pressure

Fundamental
- deposition/ burial history
- diagenesis
- kerogen type
- mineralogy
- uplift
- structural evolution
- hydrocarbon expulsion and retention
- geomechanics
- rock-fluid interactions

→

Indirect determinants
- maturity, Ro
- TOC
- depth
- pressure
- play thickness
- natural fractures
- water saturation
- drilling, completion & stimulation
- production strategy

→

Direct determinants
- matrix permeability
- matrix porosity
- reservoir pressure
- reservoir temperature
- adsorption parameters
- productive fracture surface area
- fracture spacing
- drawdown

Nature
vs
Nurture

So far our work has validated the conventional wisdom that these lists contain the key parameters

Shale Scorecard (Randy Miller)

1. Total Organic Carbon (TOC)					
Range of Values	< 1.0	1-3	3-6	6-9	>9
Assigned Score	0	4	6	8	10
2. Vitrinite Reflectance (Ro)					
Range of Values	< 0.5	0.5-1.0	1.0-1.5	1.5-2.0	> 2.0
Assigned Score	0	4	6	8	10
3. Shale Thickness					
Range of Values	< 50	50-100	100-200	200-300	> 300
Assigned Score	2	4	6	8	10
4. Gas-Filled porosity (Ave)					
Range of Values	< 2	2-4	4-6	6-8	>8
Assigned Score	0	4	6	8	10
5. Clay content (wt %)					
Range of Values	> 60	45-60	30-45	15-30	< 15
Assigned Score	2	4	6	8	10
6. Quartz content (wt %)					
Range of Values	< 15	15-30	30-45	45-60	> 60
Assigned Score	2	4	6	8	10
7. Fluid compatibility (Fresh Water; CST ratio)					
Range of Values	> 4	3-4	2-3	1-2	< 1
Assigned Score	2	4	6	8	10
8. Natural Fracture Intensity (per 10 feet)					
Range of Values	< 1	1-3	4-6	7-9	> 9
Assigned Score	2	4	6	8	10
9. Tectonic stress (σ2 versus σ3)					
Range of Values	σ2>>σ3	σ2>σ3	σ2=σ3		
Assigned Score	3	6	10		
10. Reservoir pressure gradient (psi/ft)					
Range of Values	< 0.4	0.4-0.5	0.5-0.6	0.6-0.7	> 0.7
Assigned Score	2	4	6	8	10

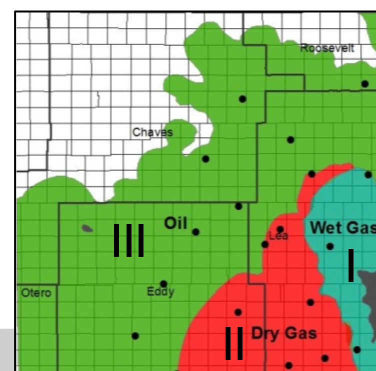
Source: Bammidi, V.S., et al, 2011, Ranking the Resource Potential of the Woodford Shale in New Mexico, SPE 144576, modified from Miller, R.S., 2010, Critical Elements of Gas Shale Evaluation: 60th Annual GCAGS Convention, San Antonio, TX

Use of Shale Scorecard: Woodford Shale in NM

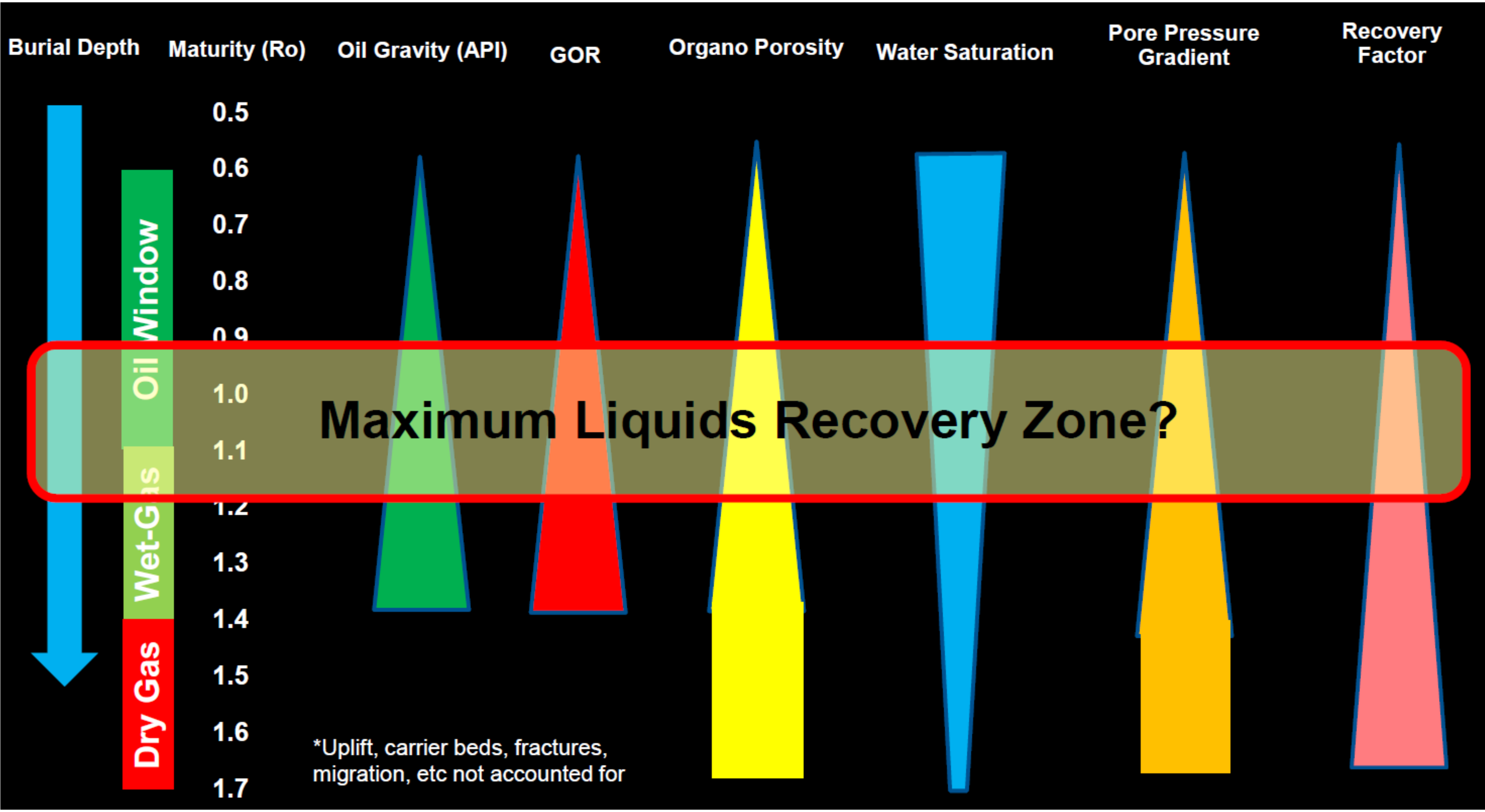
Summary of Ranking

Parameters	Ranking on the Shale Scale: Region I	Region II	Region III
Total Organic Carbon (TOC) – wt %	8	6	4
Vitrinite Reflectance (Ro) - %	6	8	4
Shale Thickness - ft	8	6	4
Gas-Filled porosity (Ave)	6	8	4
Clay content (wt %)	4	4	4
Quartz content (wt %)	6	6	6
Fluid compatibility (Fresh Water; CST ratio)	4	4	4
Natural Fracture Intensity (per 10 feet)	8	6	6
Tectonic stress (σ2 versus σ3)	10	10	6
Reservoir pressure gradient (psi/ft)	8	8	6
Total Score	**68**	**66**	**48**

Source: Bammidi, V.S., 2011, Resource Potential of the Woodford Shale in New Mexico, Search and Discovery Article #80178, modified from Miller, R.S., 2010, Critical Elements of Gas Shale Evaluation: 60th Annual GCAGS Convention, San Antonio, TX



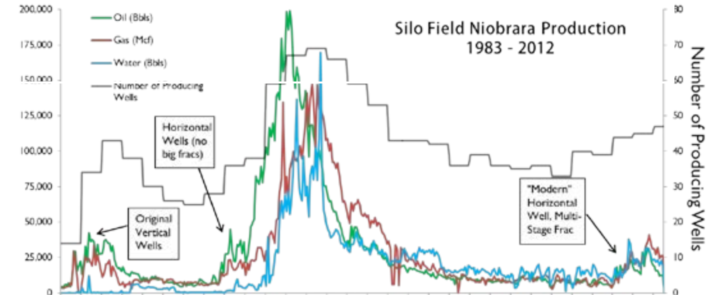
Controlling Factors

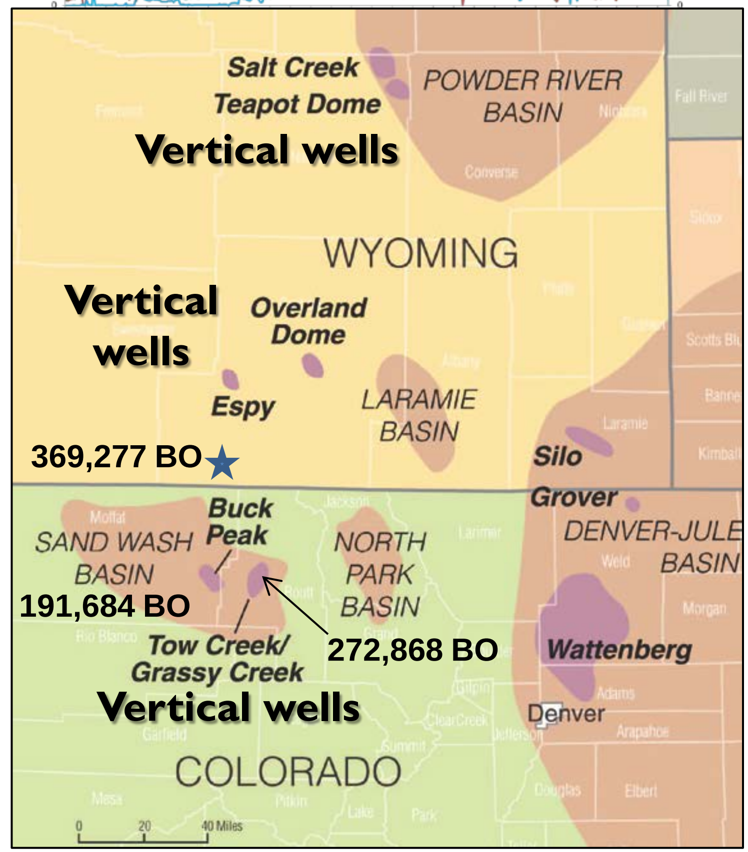


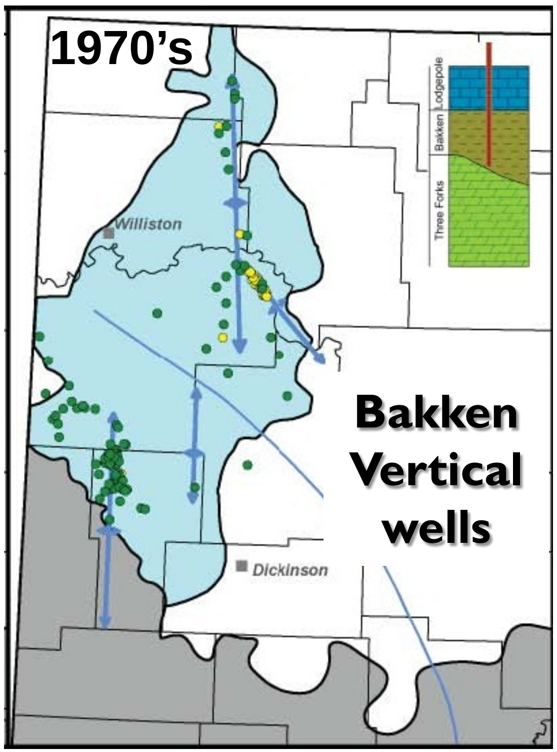
From Randy Miller – Core Labs

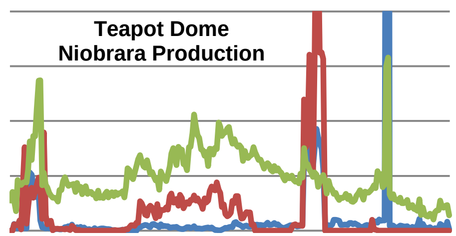
Production from Naturally Fractured Vertical Wells

What about the vertical wells into shale units that have apparently encountered natural fracture systems, resulting in commercial oil flow rates? Is it all "flush production"?

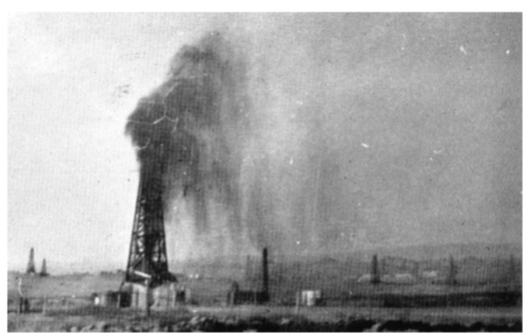








Niobrara Shale production at Teapot Dome: in 1922, Well 301 blew out and flowed 28,000 BO for six days.



Parameters of Importance in Shale Production

Symbol	Property
K_m	Matrix perm
X_f	Hydraulic Fracture spacing
Rs_i	Initial dissolved gas-oil ratio
dRs/dp	Slope of dissolved GOR
P_i	Initial pressure
n_g	Gas rel. perm exponent
C_f	Compressibility
P_{wf}	Producing BHP

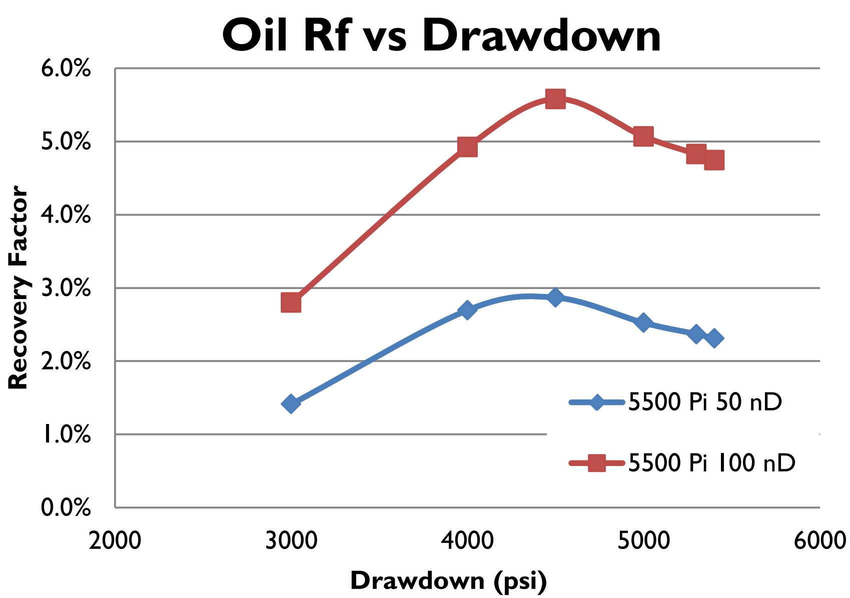
"Nature": 6 of the top 8 Parameters (geol.)

Oil Recovery from Shales

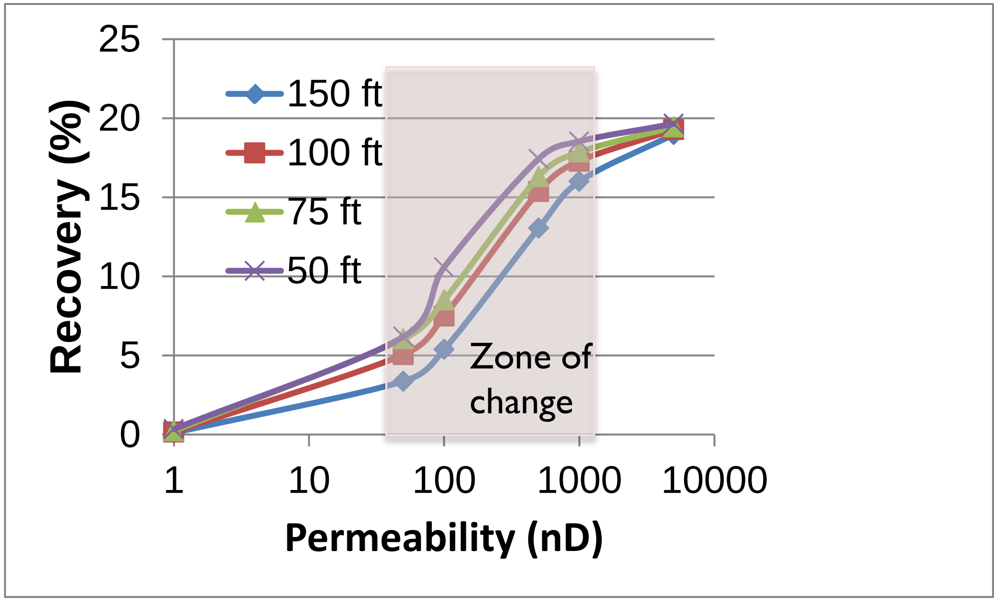
1 yr	10 yrs	20 yrs	Economic limit 5 STB/day
$*X_f$	K_m	K_m	K_m
K_m	$*X_f$	$*X_f$	Rs_i
Rs_i	Rs_i	Rs_i	$*X_f$
P_i	dRs/dp	dRs/dp	P_i
dRs/dp	P_i	P_i	C_f
$*P_{wf}$	n_g	C_f	dRs/dp
n_g	C_f	$*P_{wf}$	$*P_{wf}$
C_f	$*P_{wf}$	n_g	n_g

** Only 2 operationally controllable parameters ("Nurture")*

Optimizing "Controllable" Parameters



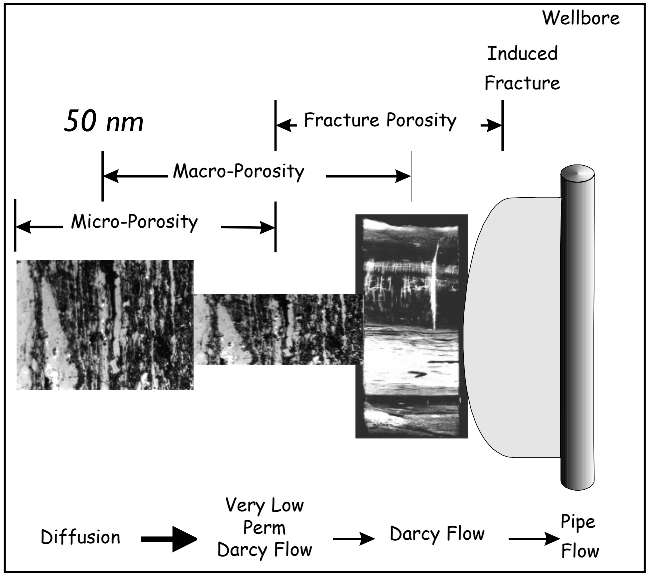
Recovery at Different Fracture Spacing



- Liquids from shales production are governed by primary production above and below bubble point (or dew point)
- Phase 1 simulation study indicates that there is an optimum with respect to drawdown for very low-permeability reservoirs
- This is due to the consideration of "relative" flow of gas to the well with respect to the liquid
- Fracture spacing also affects recovery more significantly in the 100-1000 nD range

Conventional Wisdom: "Triple Porosity Gas Storage"

- Micro- (<2 nm) and Meso-Porosity (< 50 nm)
  - Gas Storage by *Adsorption*
  - Mass Transfer by Diffusion
- Macro-Porosity (> 50 nm)
  - Gas Storage by *Solution and Compression*
  - Mass Transfer by Diffusion and $\boxed{\text{Darcy Flow}}$
- Natural or Induced Fractures
  - Gas Storage by *Solution and Compression*
  - Mass Transfer by Darcy Flow

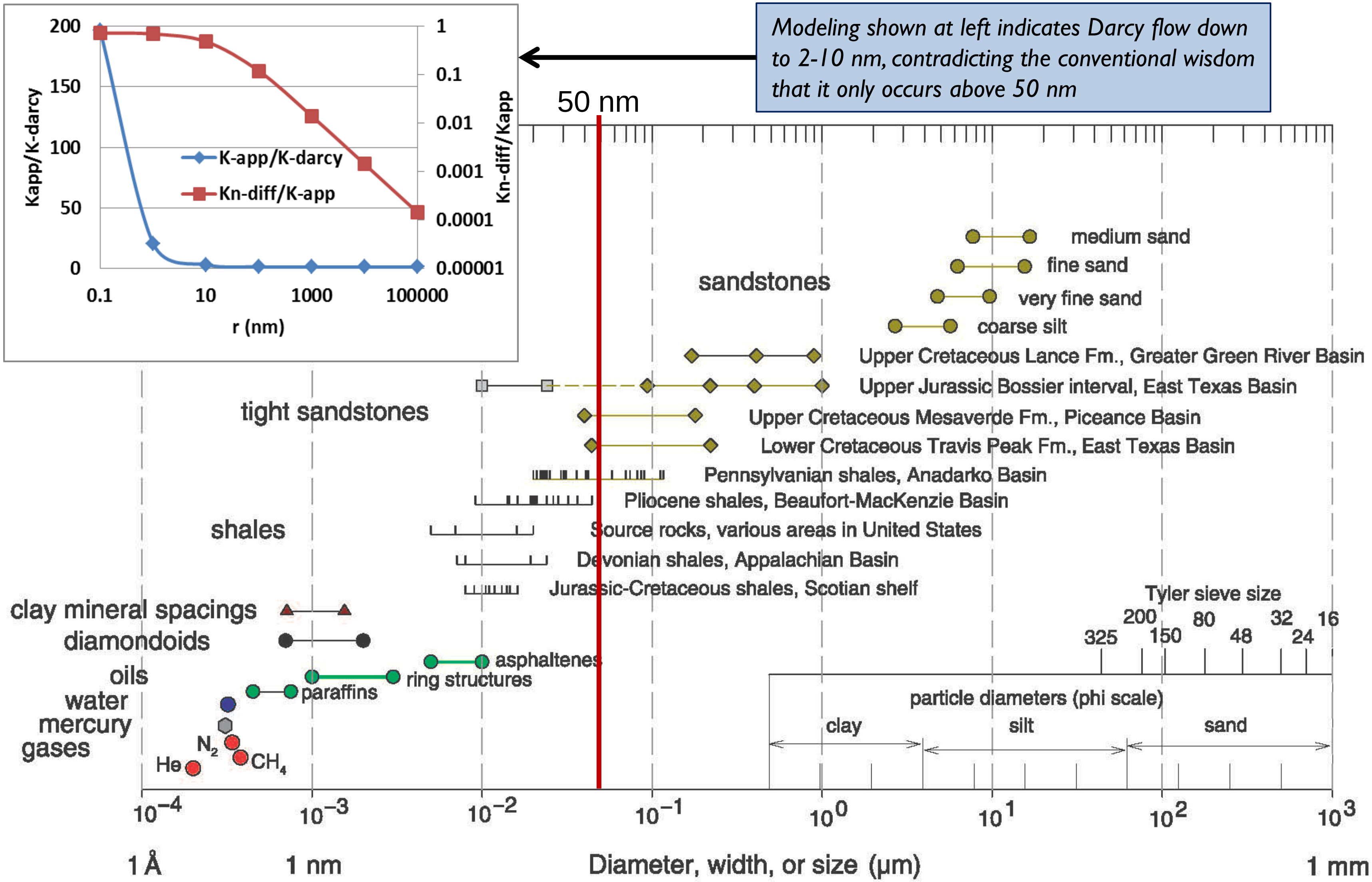


Note: Uses Roquerol et al. (1994) classification; compare to Loucks et al. (2012)

Source: ***Shale Gas Recovery Simulations & Permeability/Diffusivity, Chad Hartman, Chief Technical Advisor, Unconventional Reservoir Services, Weatherford Laboratories, presentation 9/28/2010***

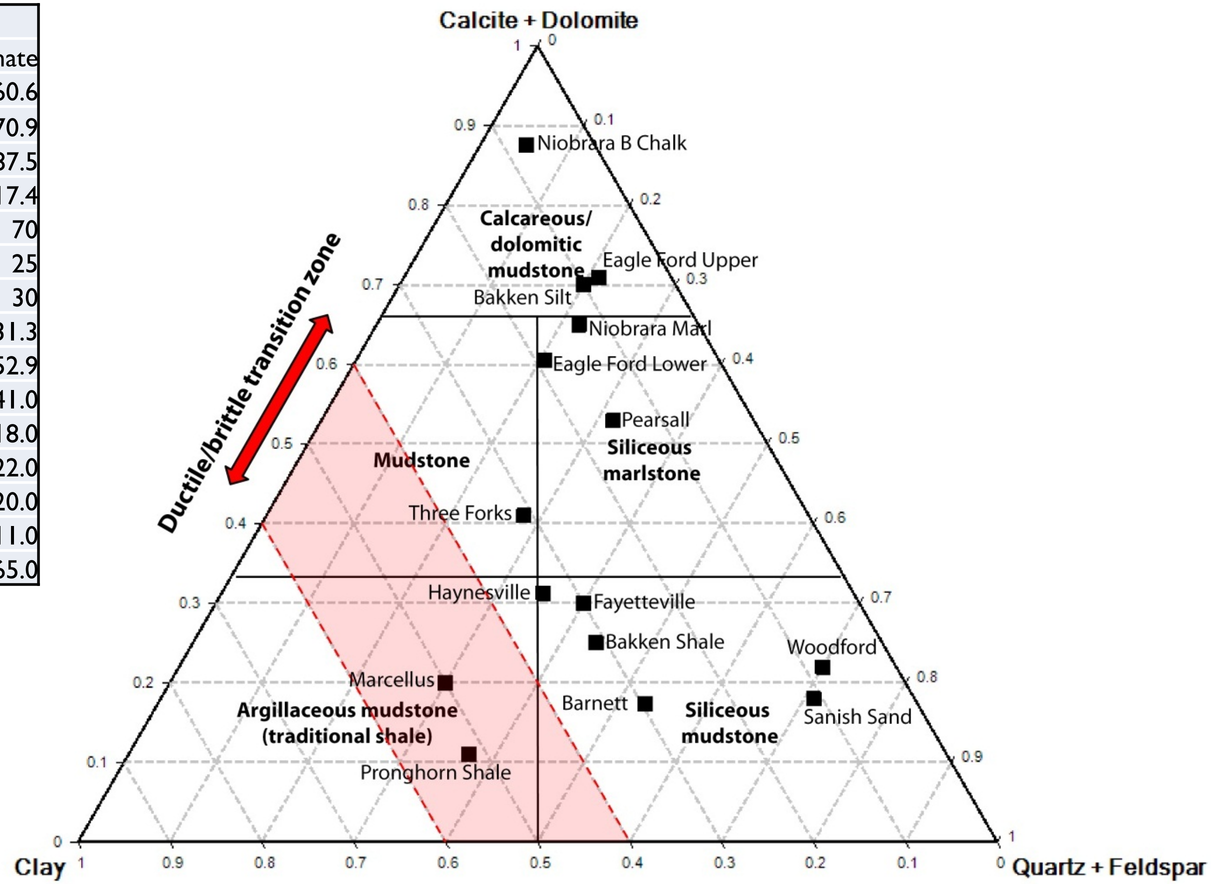
Conventional Wisdom: Darcy Flow Only at >50 nm?

Modeling shown at left indicates Darcy flow down to 2-10 nm, contradicting the conventional wisdom that it only occurs above 50 nm



Ternary Diagram – Mineralogy

Shale	Proportion in class (%)		
Formation	Clay	Silica	Carbonate
Eagle Ford L.	18.9	20.5	60.6
Eagle Ford U.	7.9	21.2	70.9
Niobrara Chalk	7.5	5	87.5
Barnett	29.6	53	17.4
Bakken Silt	10	20	70
Bakken Sh	31.2	43.8	25
Fayetteville	30	40	30
Haynesville	33.7	35	31.3
Pearsall	15.3	31.8	52.9
Three Forks	31.0	28.0	41.0
Sanish	11.0	71.0	18.0
Woodford	8.0	70.0	22.0
Marcellus	50.0	30.0	20.0
Pronghorn	52.0	37.0	11.0
Niobrara Marl	13.0	22.0	65.0



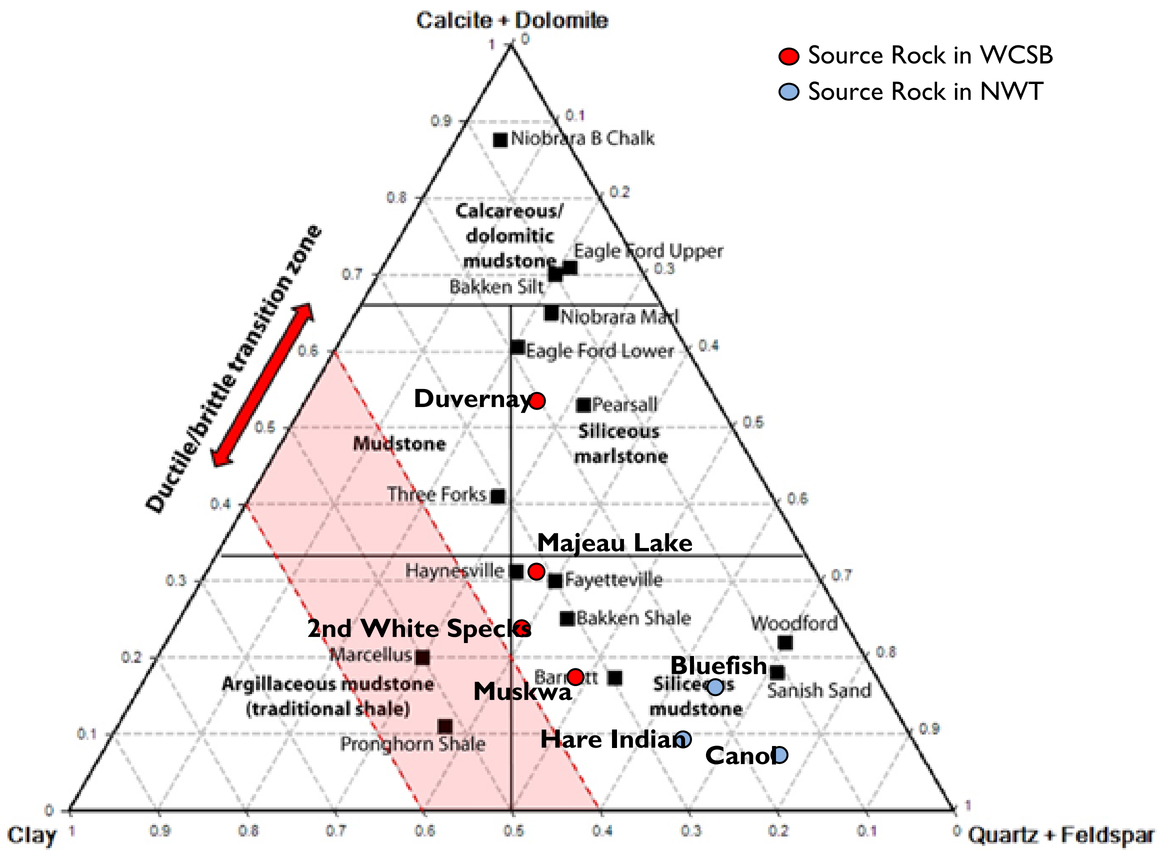
Some thoughts on mineralogy:

- *Investigate geomechanics of calcite vs dolomite rather than lump together*
- *Similarly, separate detrital quartz from biogenic silica*
- *What is contribution of feldspar fraction vs quartz behavior?*

Note:Ternary examples from the literature – confusion reigns:

- *clay on top, quartz to left*
- *quartz on top, clay to right*
- *clay on top, quartz to right*
- *carbonate on top*

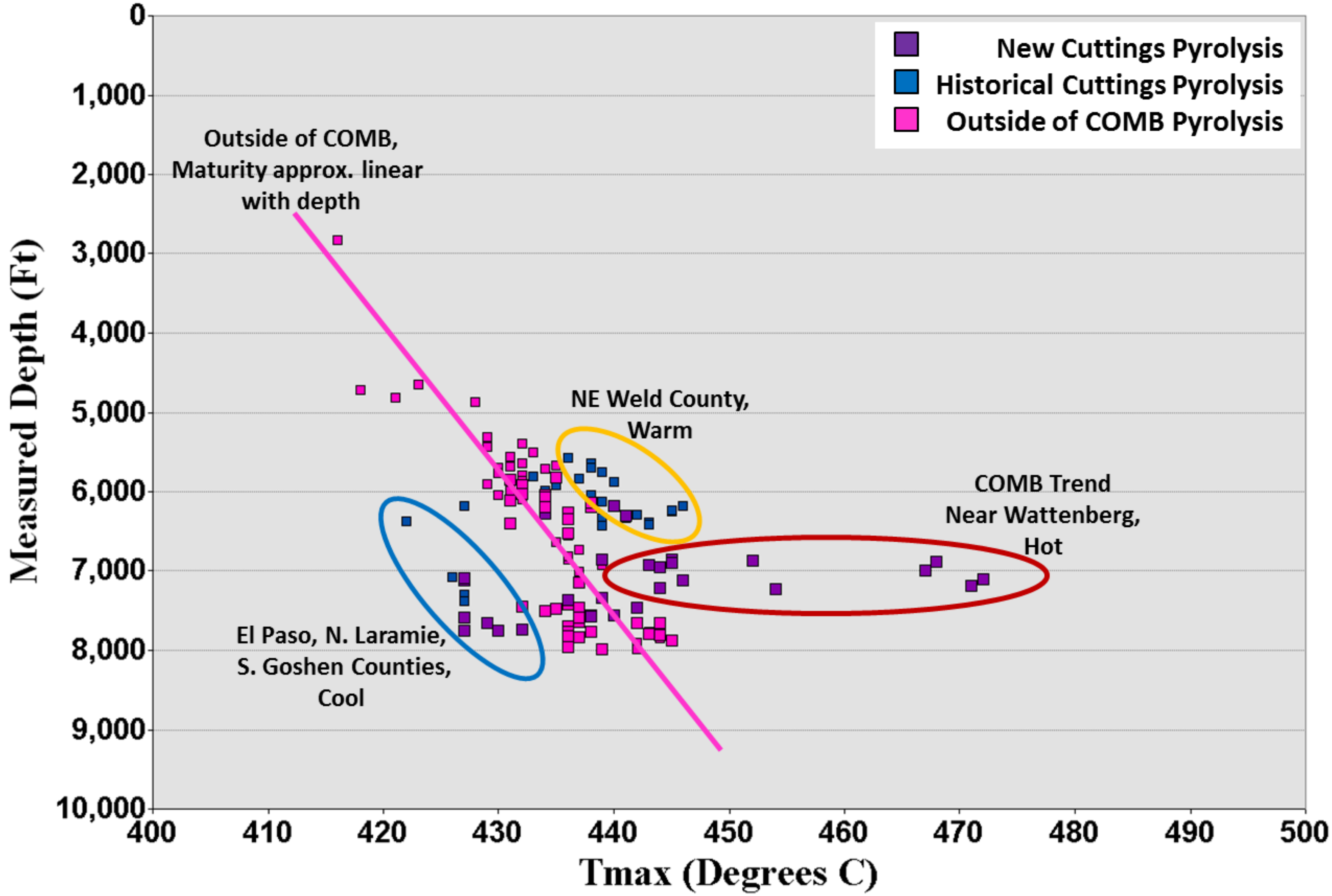
Canada Shale Mineralogy



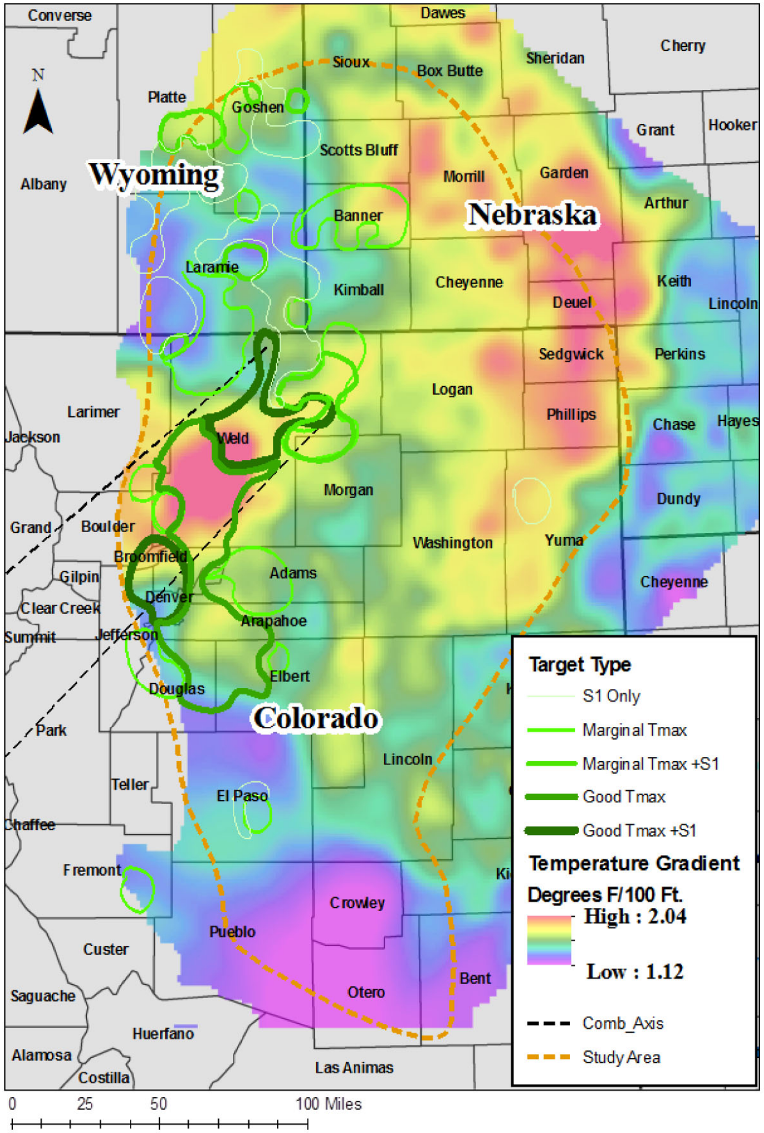
Source rock mineralogy of the selected formations are similar to analogs in the United States.

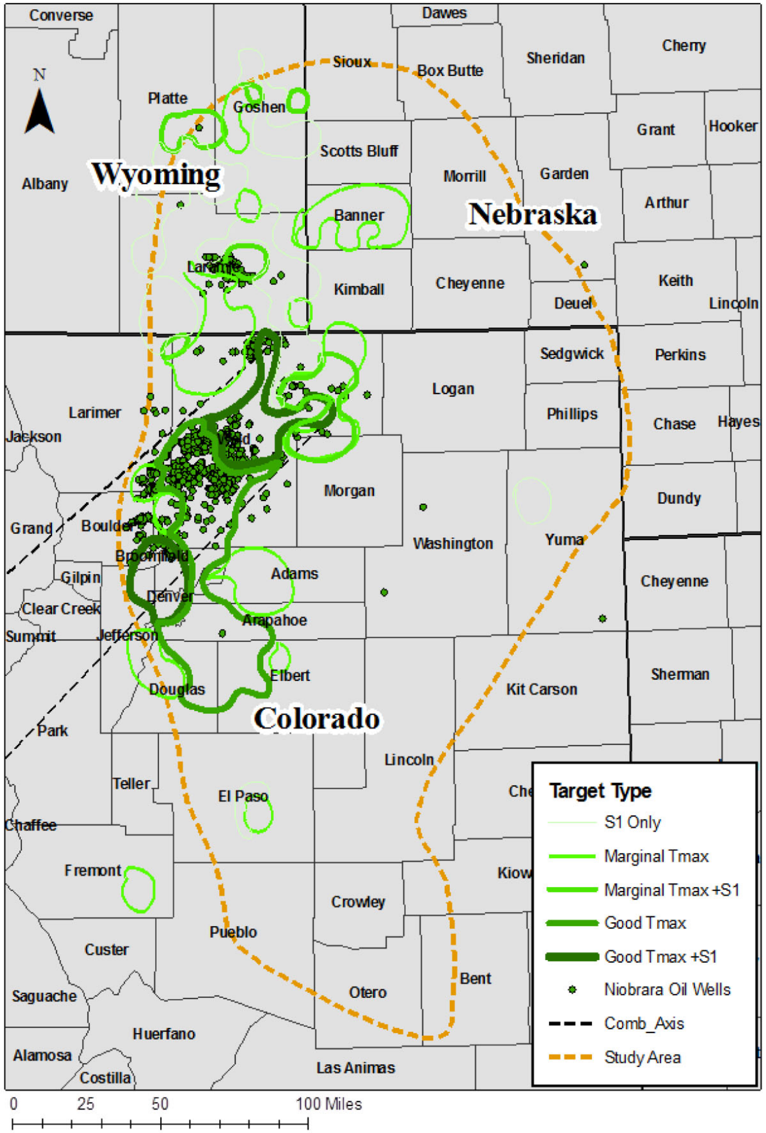
- The Bluefish, Canol and Hare Indian samples are similar in composition to siliceous mudstones like the Woodford and Barnett.
- The Duvernay is similar to the Pearsall.
- The Muskwa is similar to the Barnett
- The Majeau Lake is similar to the Haynesville and Fayetteville.

Maturity & Depth in the Denver Basin

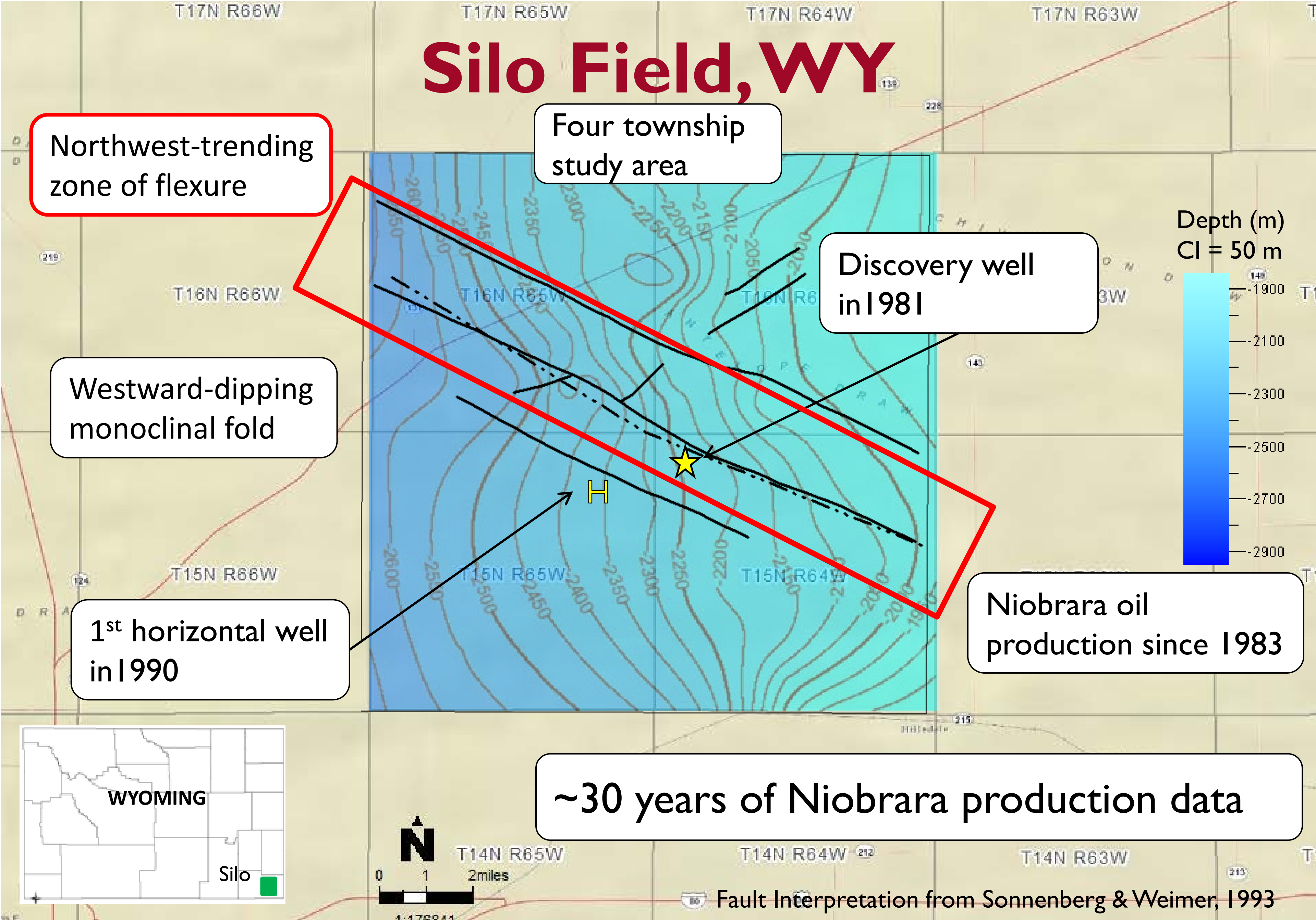


Denver Basin Niobrara

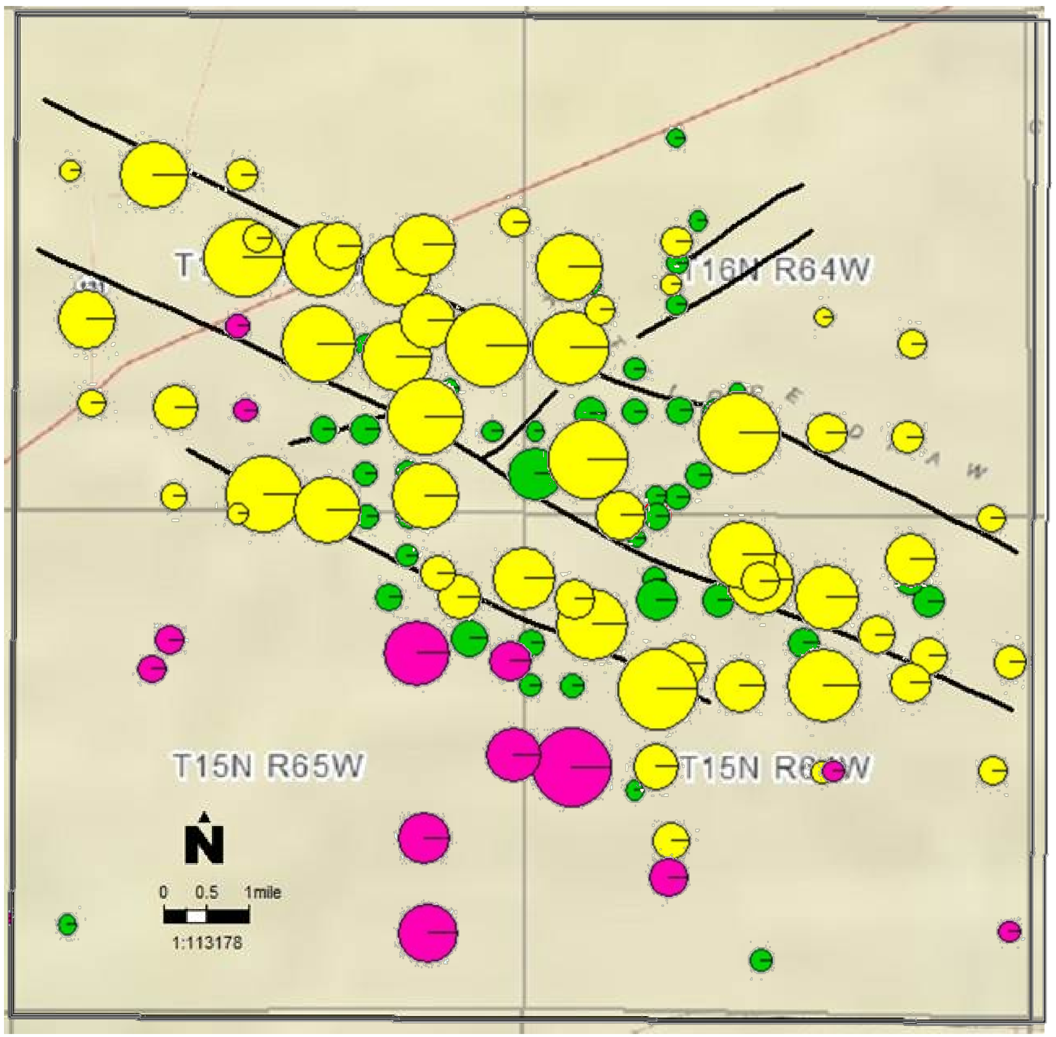




Silo Field, WY



Silo Field Drilling History



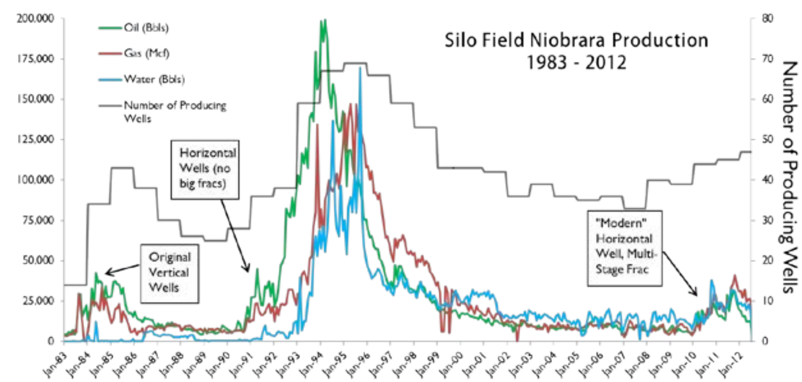
Total field cumulative:
10.8 MMBBLS
9,751 MMCFG

1st year Cumulative Oil (MBBLS)

- > 80
- 45 – 80
- 15 – 45
- 5 – 15
- < 5,000

Drilling Era

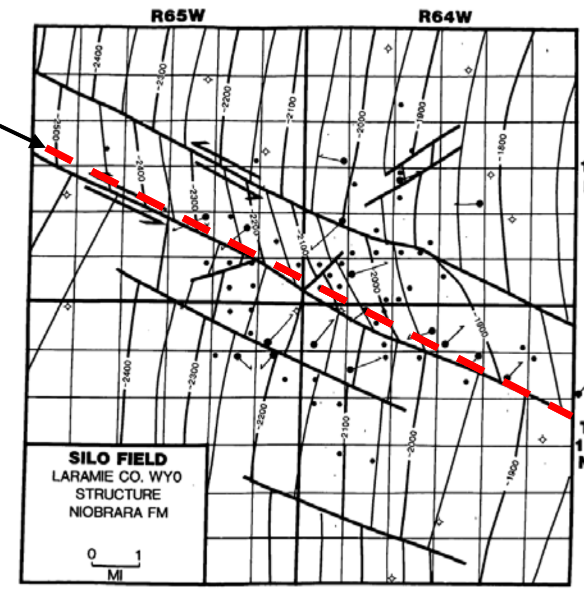
- 1980s vertical
- 1990 horizontal
- modern horizontal



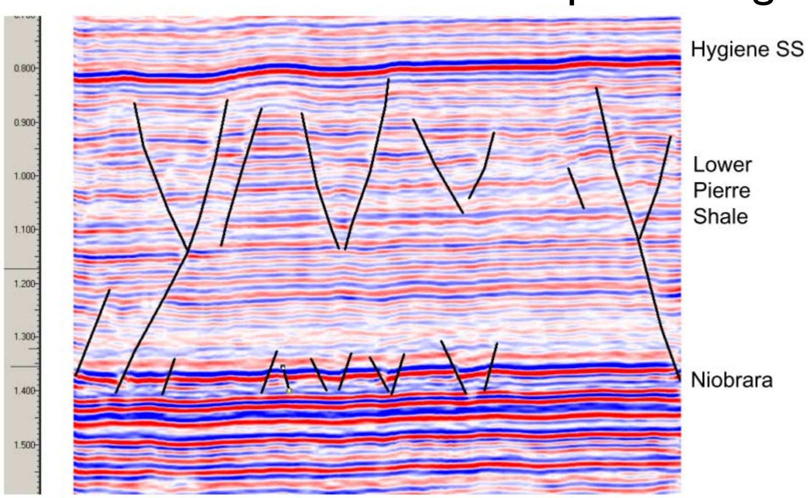
Silo Field Previous Studies

- Natural fractures recognized as important for increased storage and deliverability
  - Increased resistivity indicates presence of oil-filled natural fractures
    - Johnson & Bartshe (1991a&b)
    - Sonnenberg & Weimer (1993)
- Origin of fractures
  - Differential Compaction (Thomas, 1992)
  - Wrench fault and fracture model (Sonnenberg & Weimer, 1993)
  - Basement Tectonics (Svoboda, 1995)
  - Permian-aged salt dissolution edge (Oldham, 1996)
  - Polygonal Fault System (Sonnenberg and Underwood, 2012)
- "Calcite-healed fractures are not storage, but are zones of weakness that re-open during hydraulic frac"

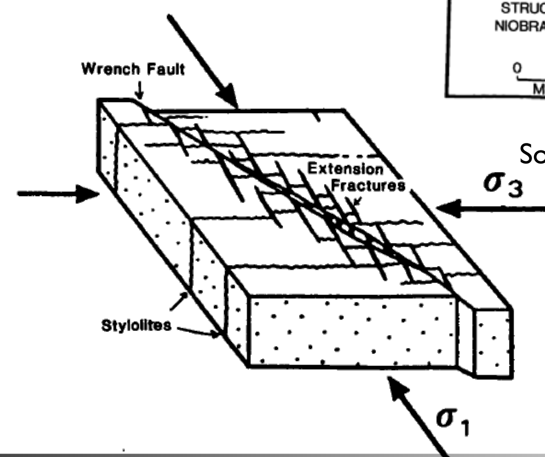
Salt edge



Sonnenberg and Weimer (1993)

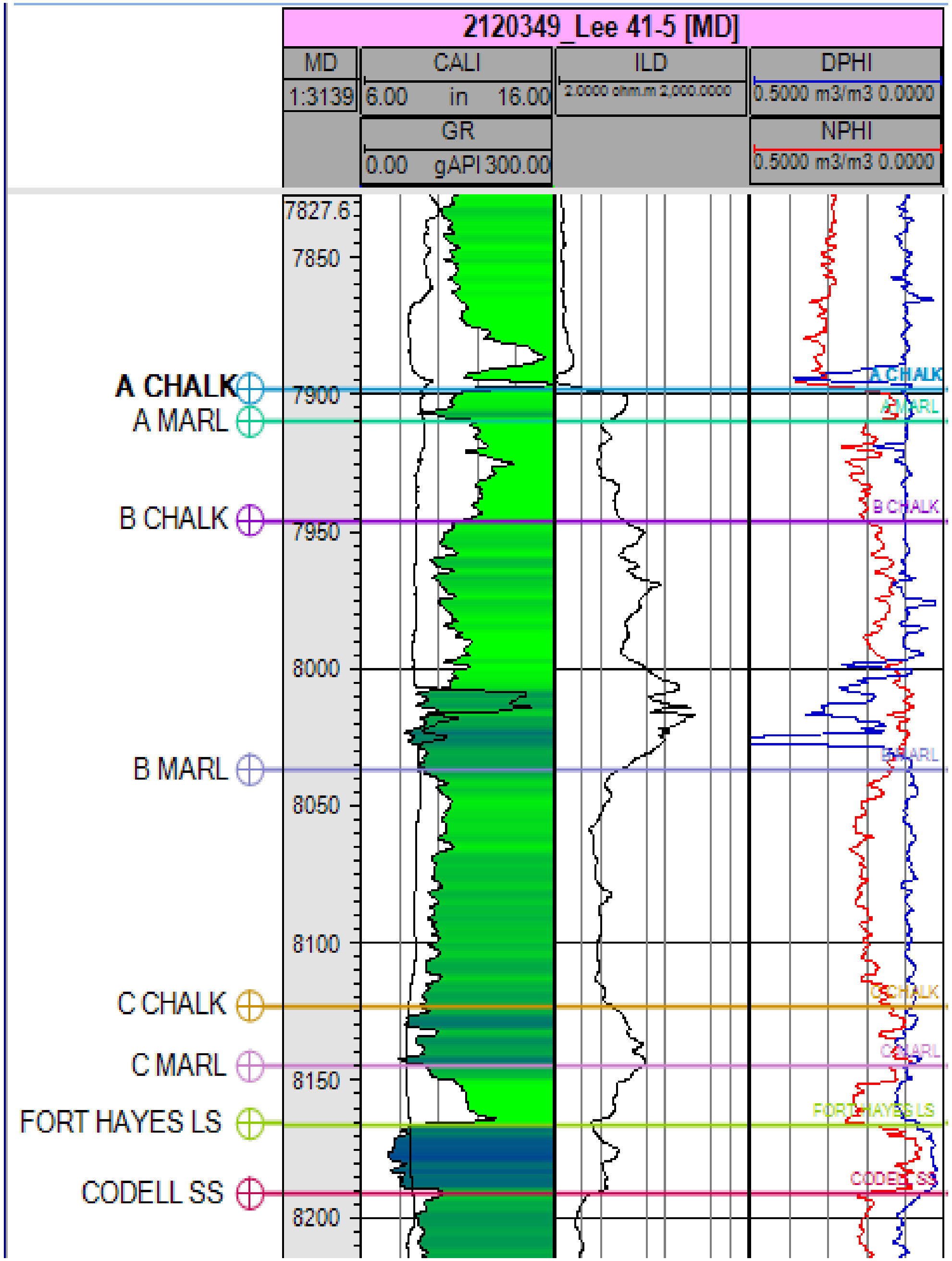


Sonnenberg (2012)



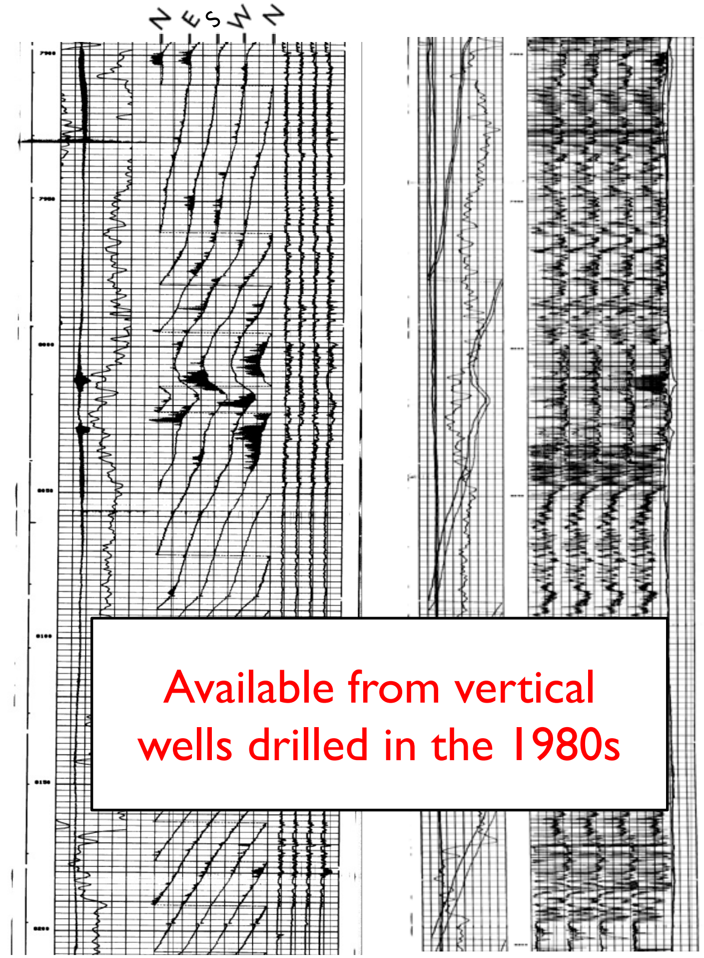
Wrench fault model proposed by Sonnenberg and Weimer (1993) is used in this study

Fracture Identification Logs



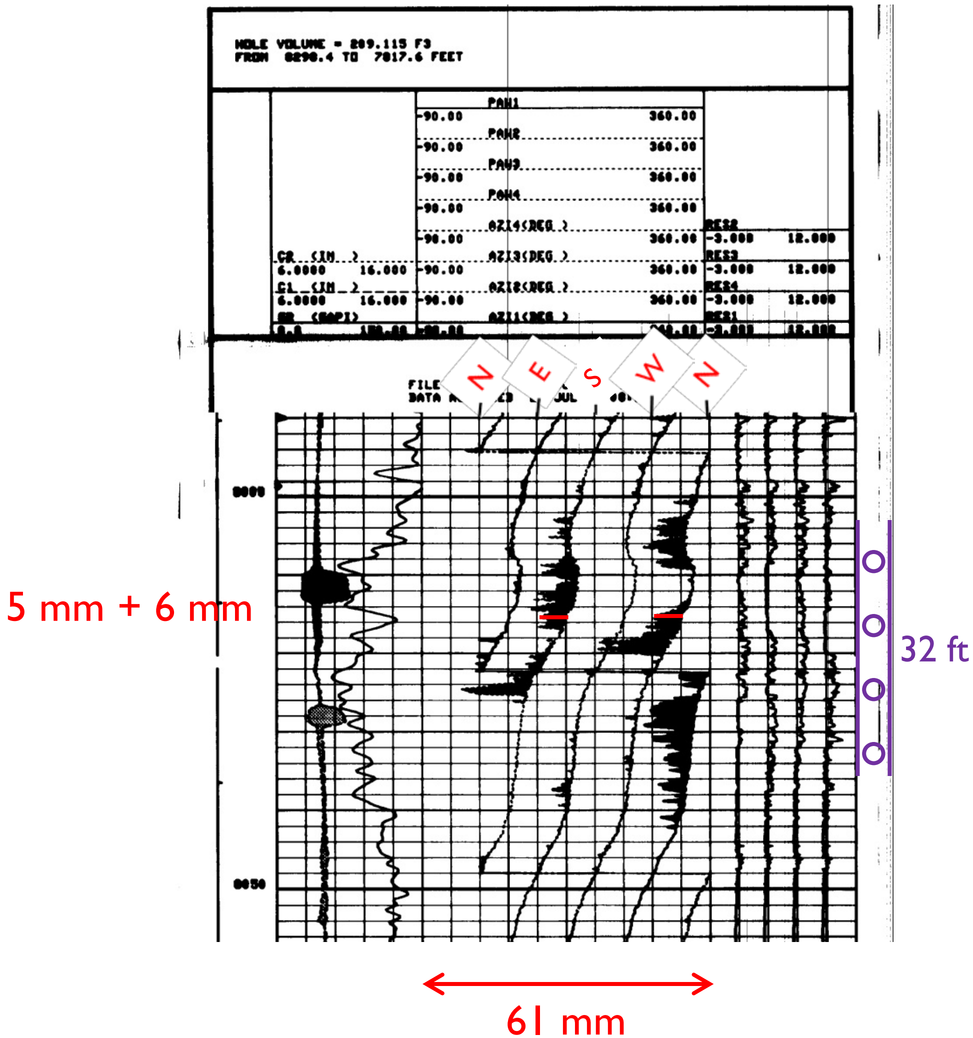
Oriented Micro Resistivity Log (OMRL)

Fracture Identification Log (FID)



Available from vertical wells drilled in the 1980s

Quantifying Fracture Intensity (FI)



Fracture Intensity by foot:

Example:

$$FI = \frac{11\ mm}{61\ mm} \times 100 = 18$$

(Calculated by foot intervals)

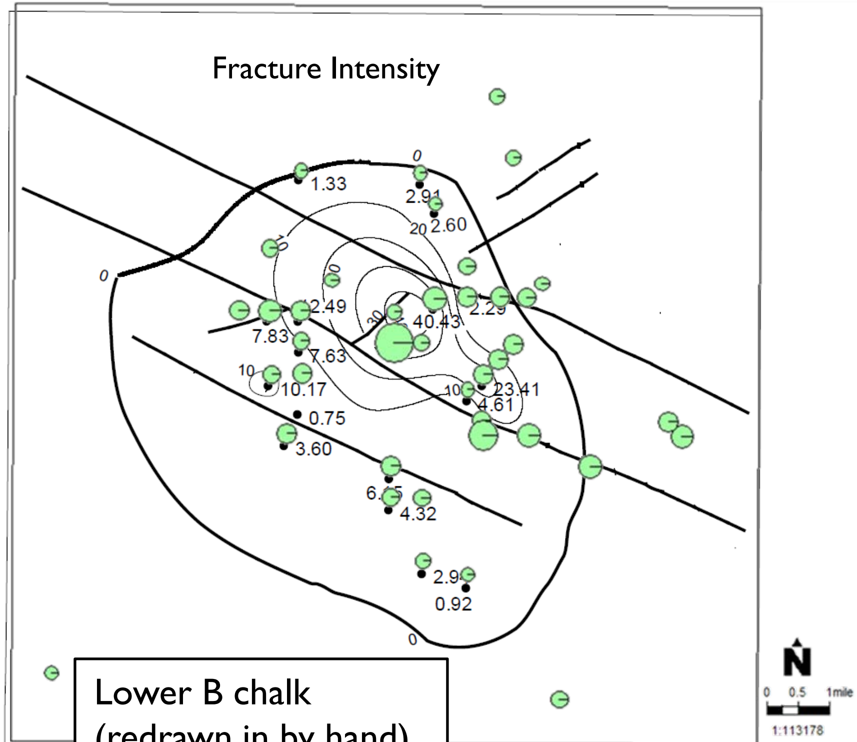
Average FI per foot Lower B chalk:

Example:

$$= \frac{\sum FI}{Lower\ B\ chalk\ thickness}$$

$$= \frac{560}{32} = 17.5$$

Fracture Intensity (averaged by zone)

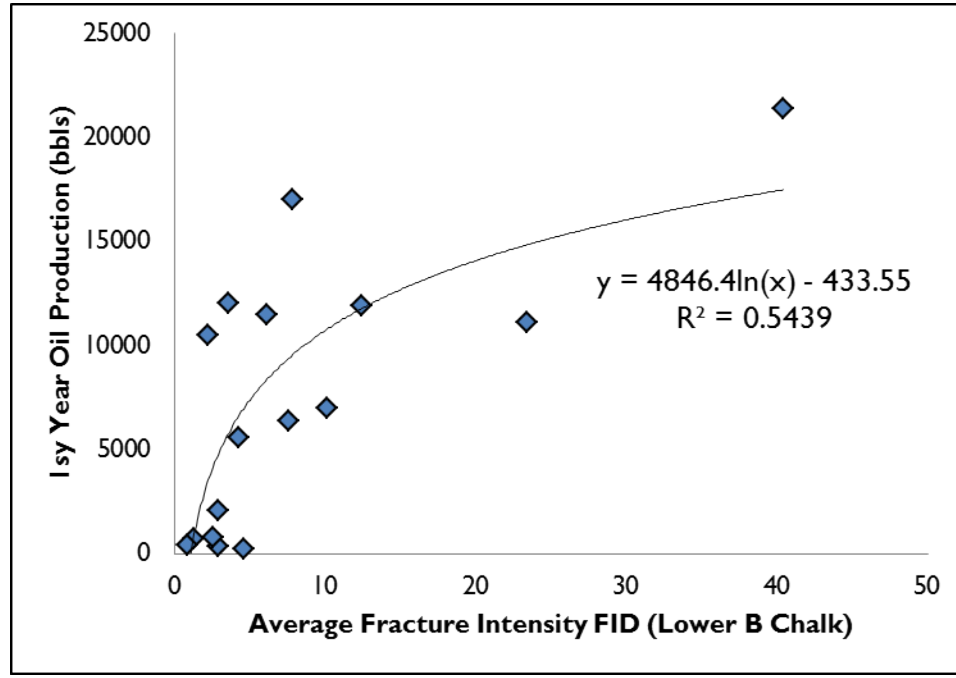


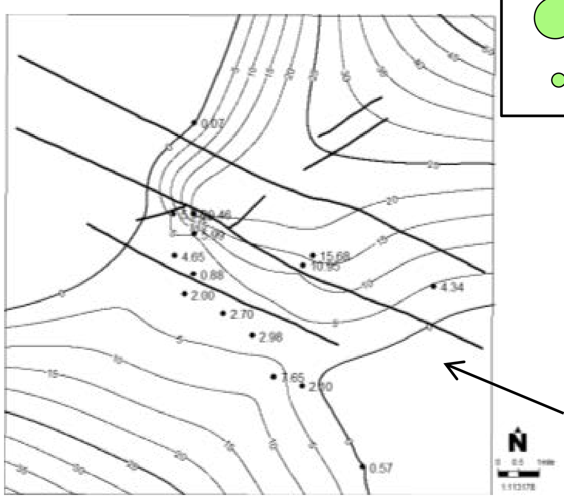
Lower B chalk (redrawn in by hand)

1st Yr Oil (completed in the Lower B chalk)

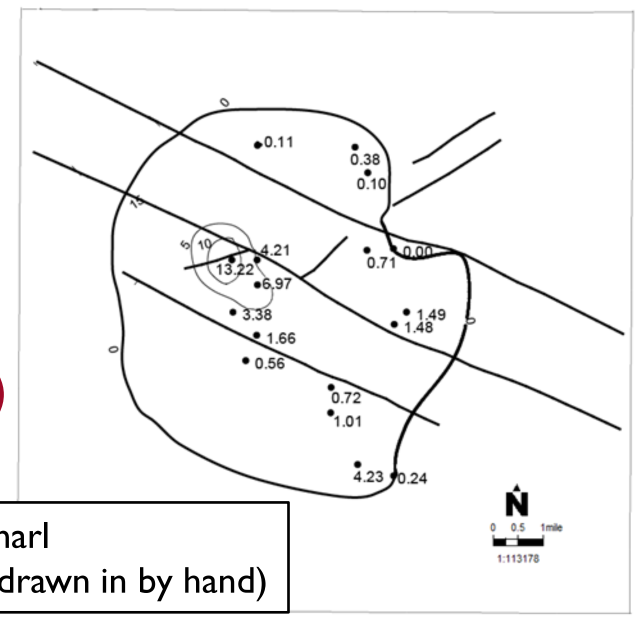
52.6 Mbbls

0.2 Mbbls



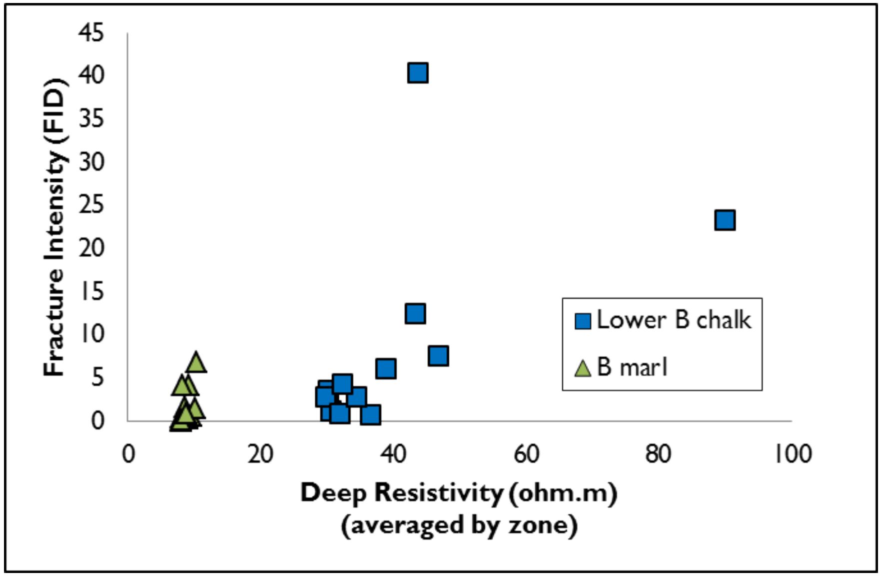


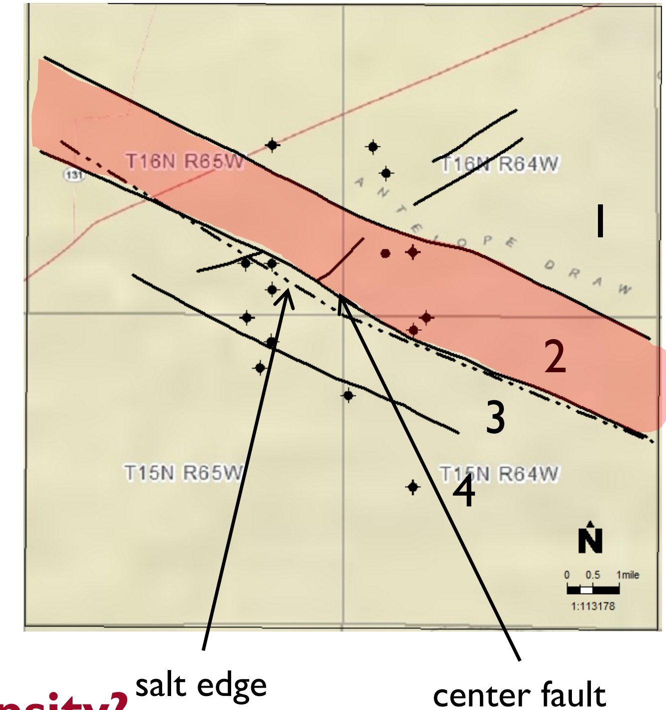
Example of Lower B chalk fracture Intensity contoured by computer algorithm



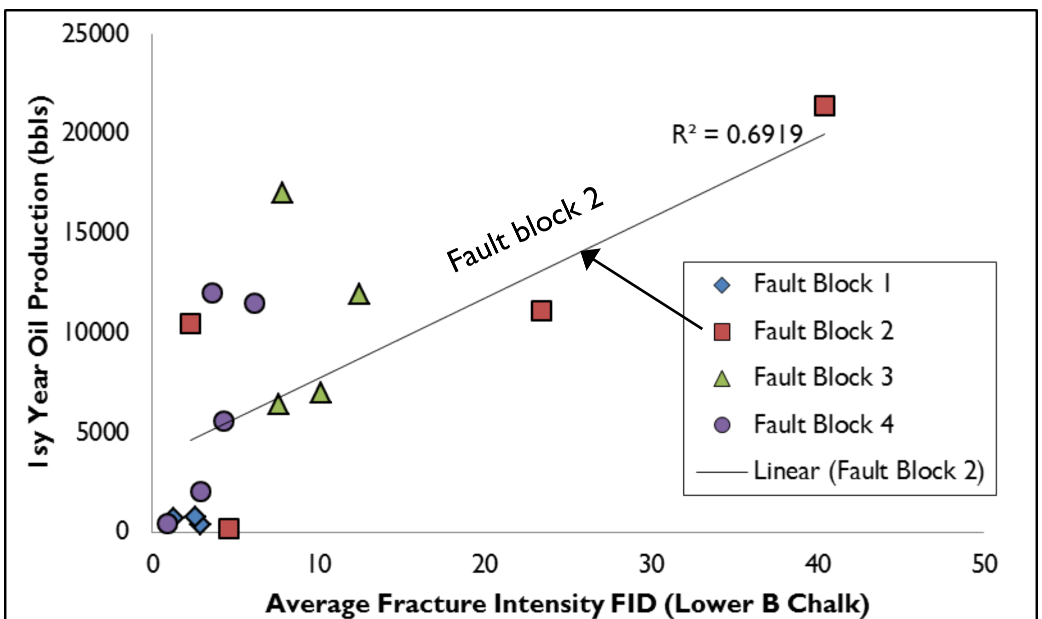
B marl (redrawn in by hand)

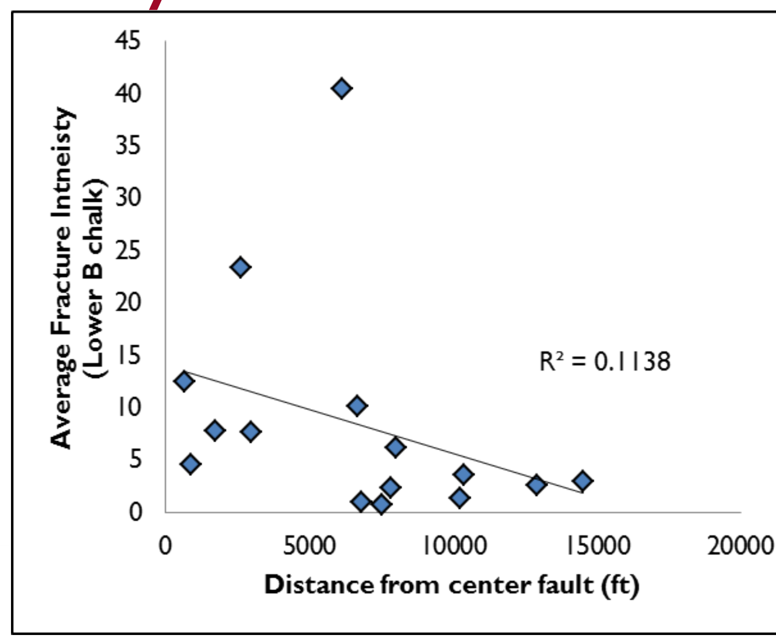
Resistivity as an indicator of natural fractures





Tectonic control on fracture intensity?





Multi-Resolution Micro- Nano-Scale Imaging: Summary

Micro/chemical

CT

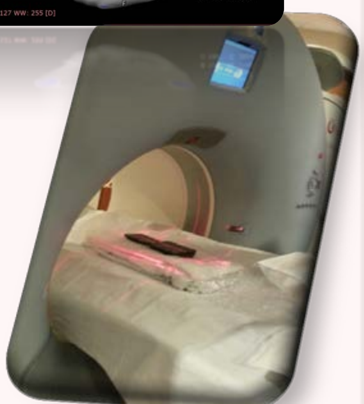
Mineralogy, fabrics, porosity, fractures

Digital mapping: XRF

Mineralogy, fabrics, porosity, fractures

XRF

Bulk (major) element quantification and mapping



Micro/chemical

Petrography

Mineralogy, fabric, microtectonics, microstructures

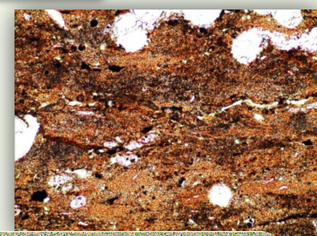
QEMSCAN®

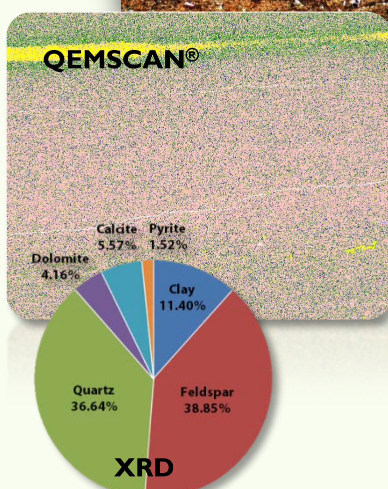
Mineralogy, fabric, microtectonics, microstructures

XRD

Clay quantification and analysis

Petrography





Micro- nano-scale

SEM

Ion Milling

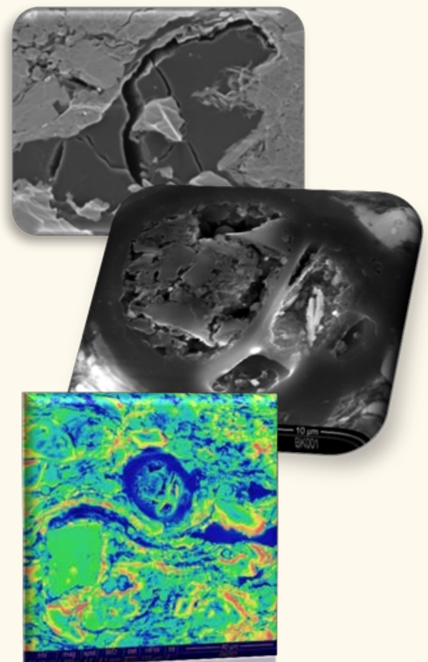
Micro to nano-scale evaluation of samples

FIB-SEM

Micro to nano-scale (including 3D) evaluation of samples

TEM/STEM

Micro to nano-scale (including 3D) evaluation of samples



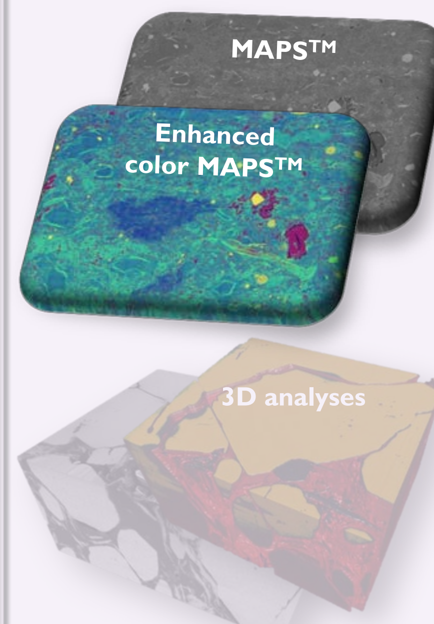
Macro- nano-scale

Data Integration

2D Exploration: Mineralogy, porosity and petrofabrics

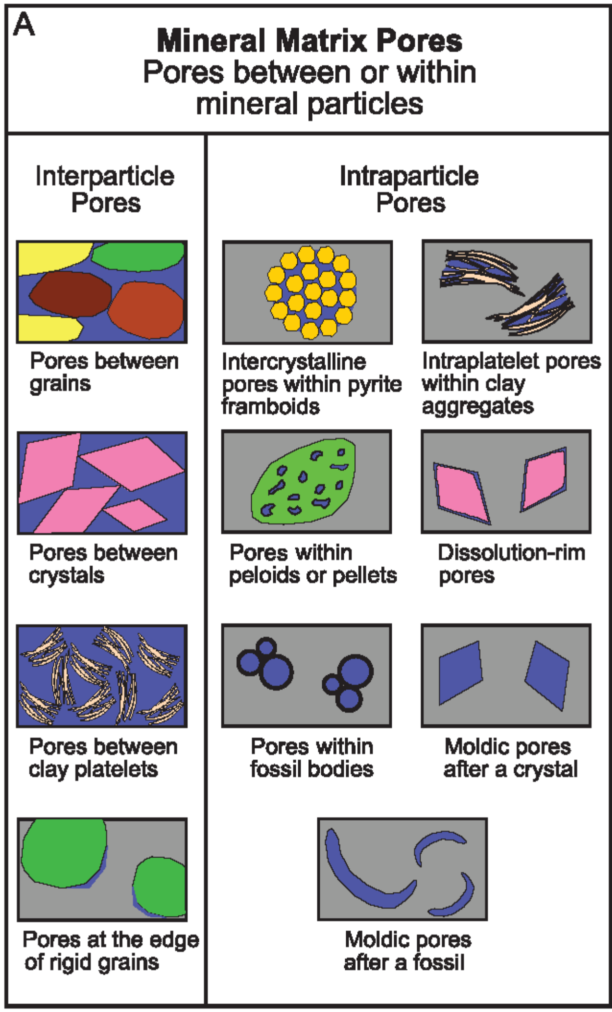
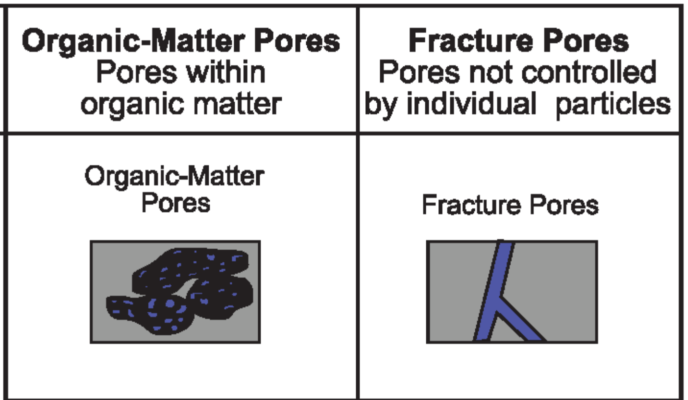
Data Integration

3D Exploration: Mineralogy, porosity and petrofabrics



NB. Metadata and imaging Integration

Carbonate Pore Type Classification

Organic matter pores:

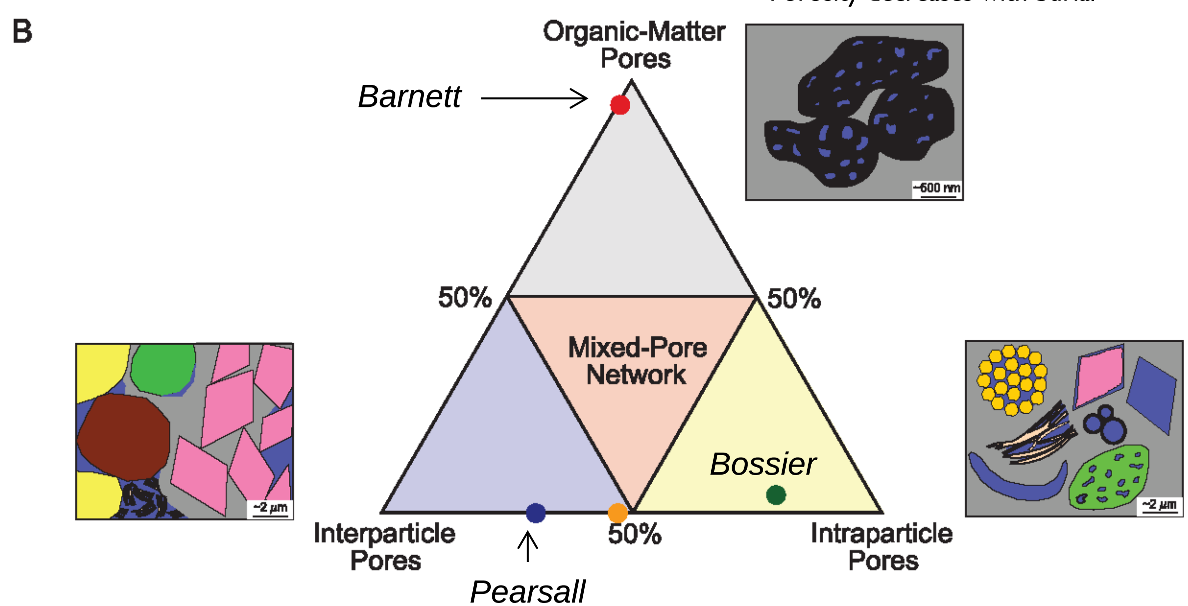
- Result of oil generation in kerogen
- Hydrophobic (oil-wet)
- Porosity increases with maturity (which increases with burial)

Interparticle pores:

- Classic conventional reservoirs
- Hydrophyllic (water-wet)
- Porosity decreases with burial

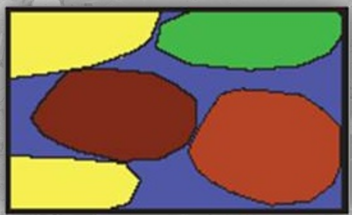
Intraparticle pores:

- Unconventional reservoirs
- Clay booklets, pyrite framboids, fecal pellets, fossil molds
- Porosity decreases with burial

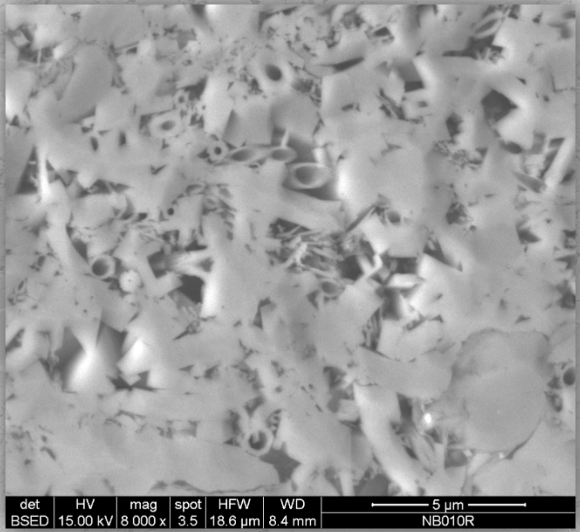


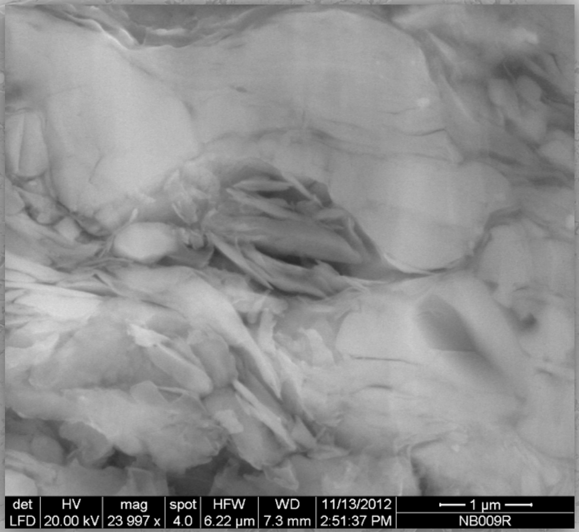
Loucks, Robert G., Robert M. Reed, Stephen C. Ruppel, and Ursula Hammes, 2012, **Spectrum of pore types and networks in mudrocks and a descriptive classification for matrix-related mudrock pores**: AAPG Bulletin, v. 96, no. 6 (June 2012), pp. 1071–1098

Interparticle Pores

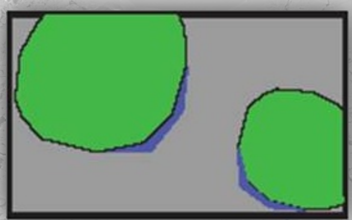


Interparticle

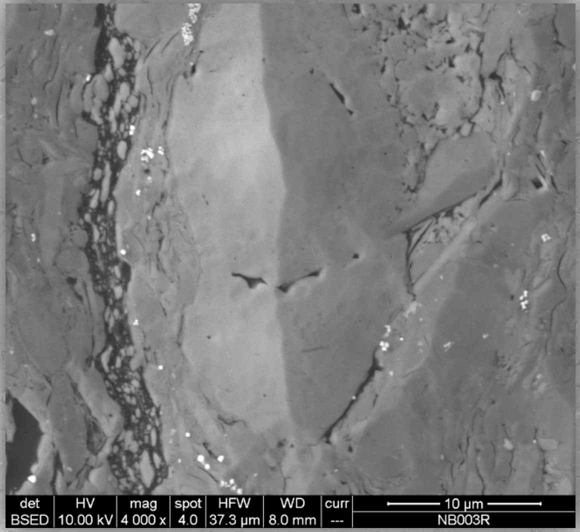


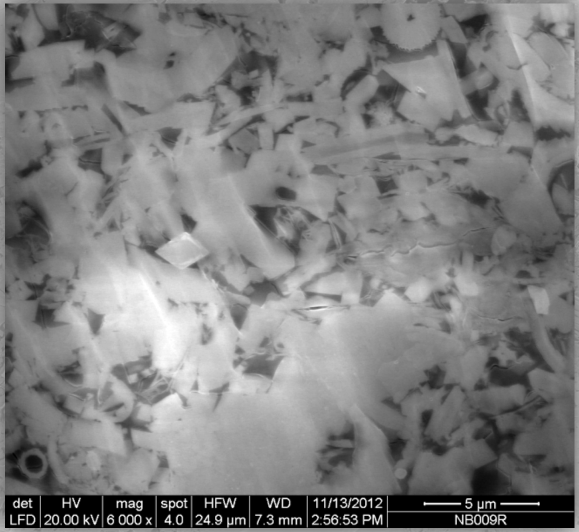


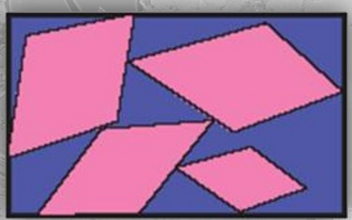
Interplatelet



Grain Edge



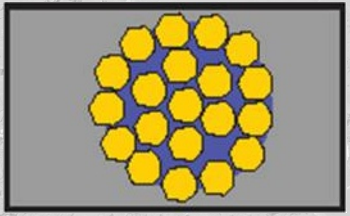




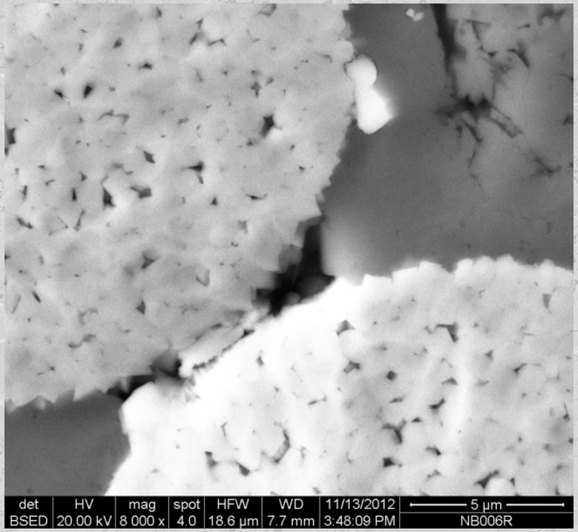
Intercrystal

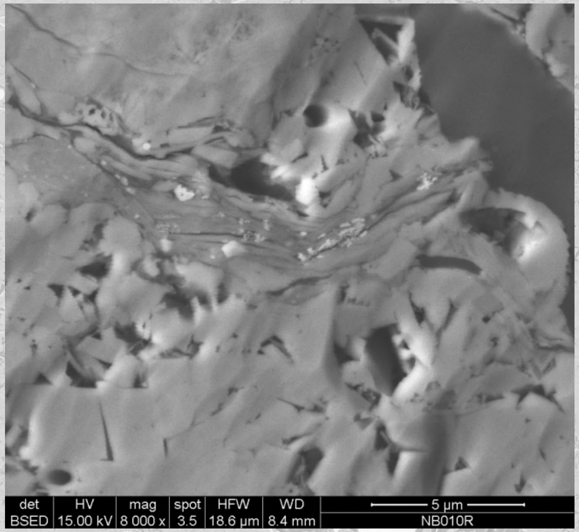
- **Student: Peter Pahnke, MS candidate**
- **Thesis advisor: Dr. Scott Ritter, Brigham Young University**
- **Thesis committee includes Tom Anderson, Adjunct Professor for BYU**

Intraparticle Pores

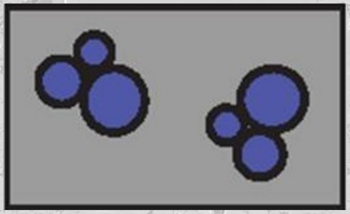


Intercrystalline

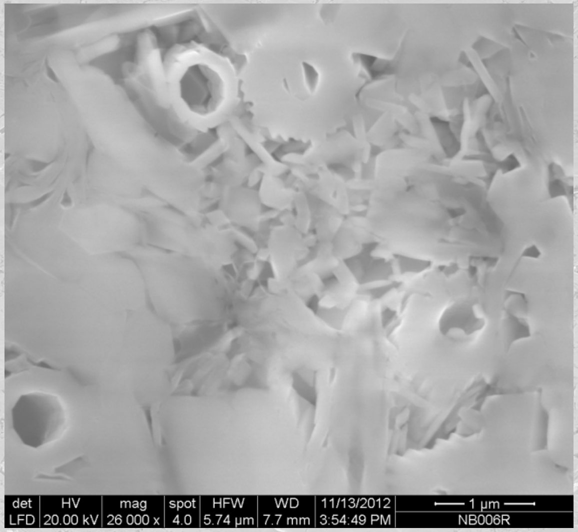


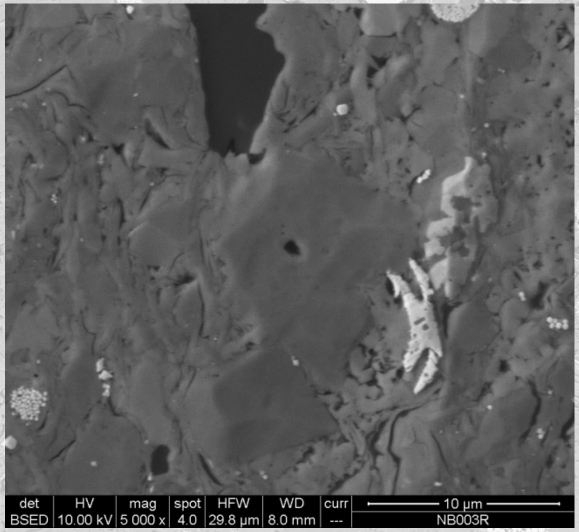


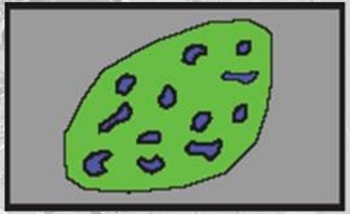
Intraplatelet



Intraparticle



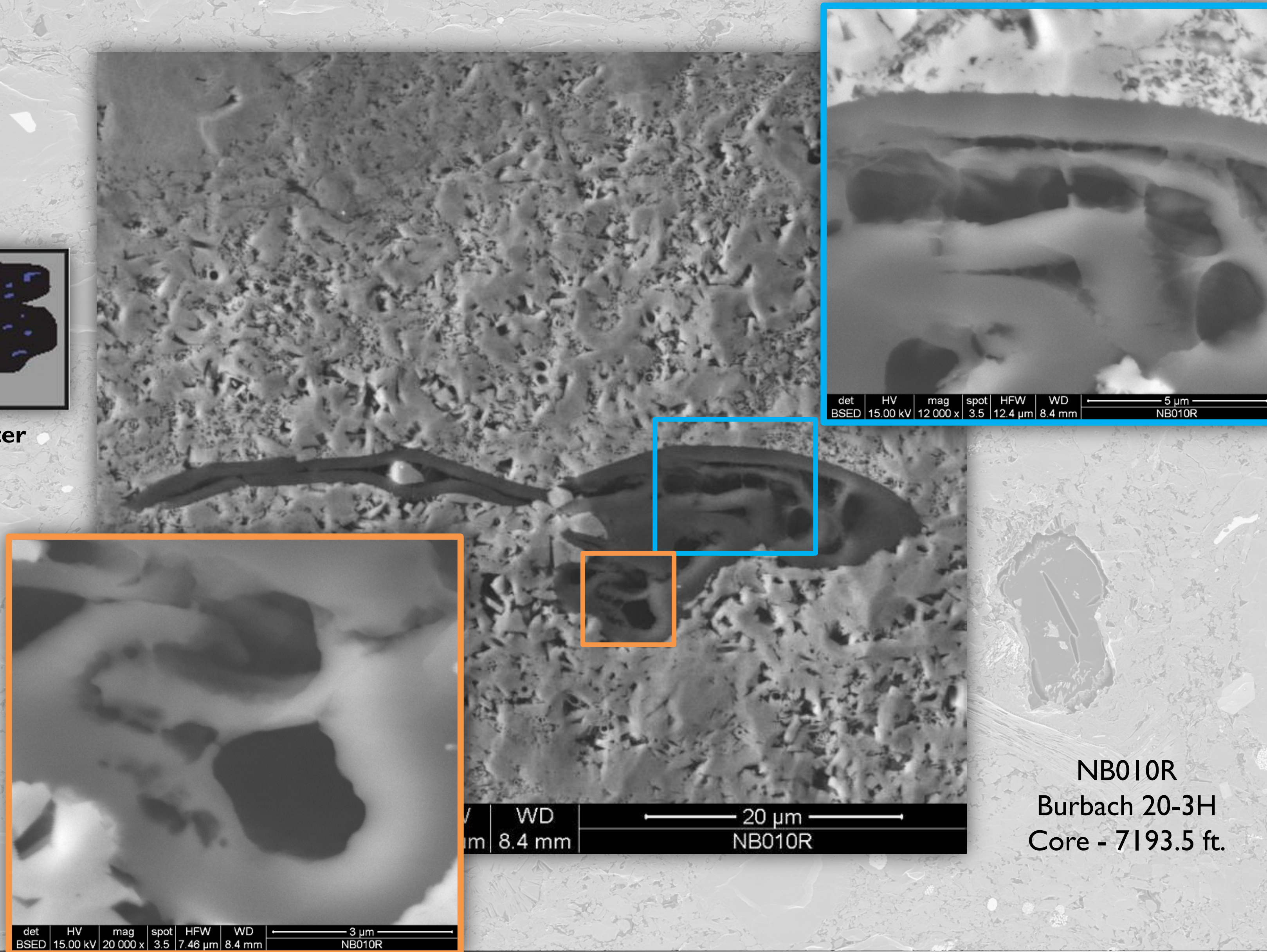




Intragranular

Organic-Matter Pores

Organic Matter

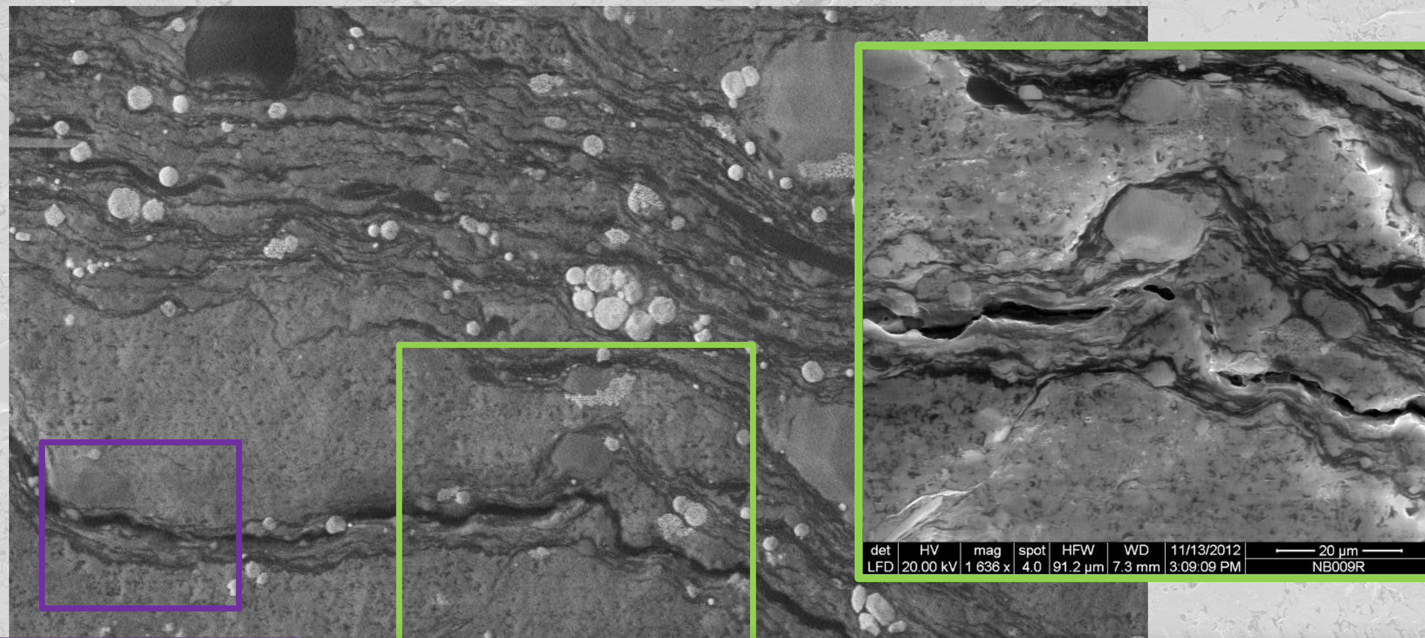
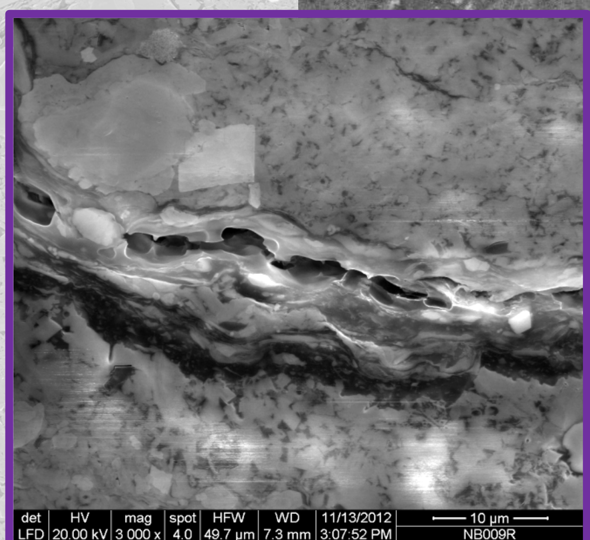


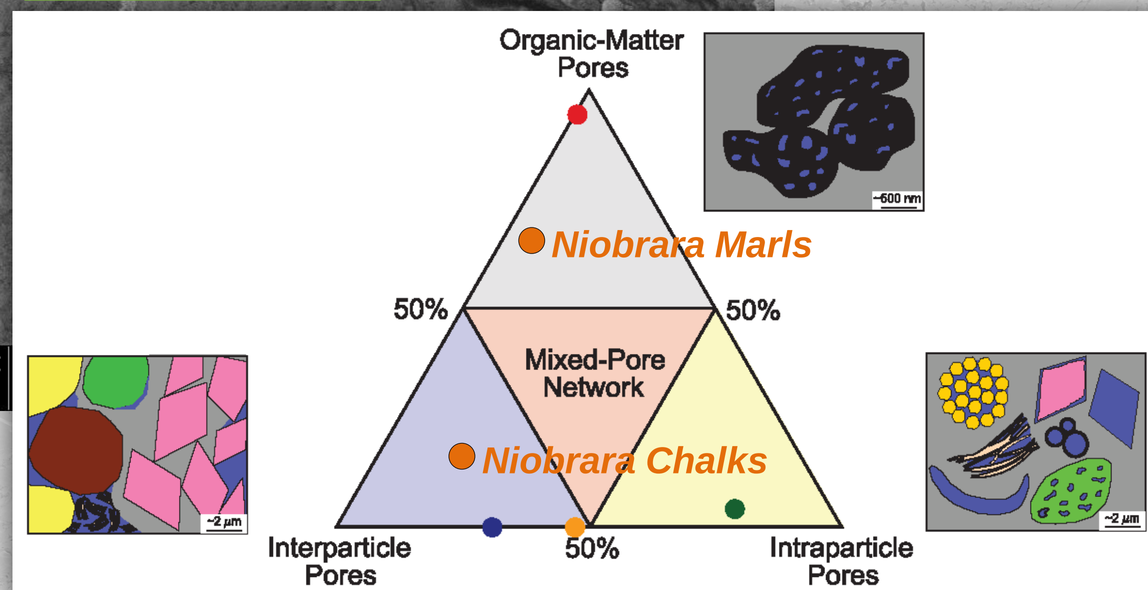
NB010R
Burbach 20-3H
Core - 7193.5 ft.

Fracture Pores

NB009R
Burbach 20-3H
Core - 7185.3 ft.

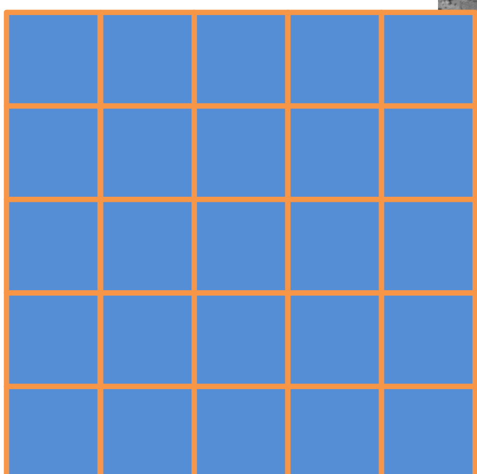
Fracture Pores



MAPS™ Software to "Stitch" SEMs

Niobrara B Chalk
Sample No. NB006R
Mobil Oil Horse Creek
Core – 4202.5 ft



Composite is 5x5 = 25 individual images