My Source Rock is Now My Reservoir - Geologic and Petrophysical Characterization of Shale-Gas Reservoirs*

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Abstract

Many currently producing shale-gas reservoirs are overmature oil-prone source rocks containing Type I or Type II kerogen. Key characterization parameters are: total organic carbon (TOC), maturity level (vitrinite reflectance), mineralogy, thickness, and organic matter type (OMT). Recent studies indicate that although organic-rich shale-gas formations may be hundreds of meters in gross thickness (and may appear largely homogeneous), the vertical variability in the organic richness and mineralogy can vary on relatively short vertical scales (e.g., 10's centimeters - 1 meter). The vertical heterogeneity observed can be directly tied back to geologic and biotic conditions when deposited. The accumulation of organic-rich rocks (ORRs) is a complex function of many interacting processes that can be summarized by three main control variables: rate of production, rate of destruction, and rate of dilution. The marine realm includes three physiographic settings that accumulate significant organic-matter-rich rocks: constructional shelf margin, platform/ramp, and continental slope/basin. In general, the fundamental geologic building block of shale-gas reservoirs is the parasequence, or its equivalent, and commonly 10's to 100's of parasequences comprise the organic-rich formation whose lateral continuity can be estimated, using techniques and models developed for source rocks.

Many geochemical and petrophysical techniques developed to characterize organic-rich source rocks in the oil-generation window (Ro=0.5-1.0) can be applied, sometimes with modification, to shale-gas reservoirs that currently exhibit high thermal maturity (Ro=1.1 - 4.0). Well logs can be used to calculate TOC, porosity, and hydrocarbon saturation, but in clay-rich mudstones, the fundamental definition of porosity is complicated by the high surface area of clay minerals (external and sometimes internal), the volume of surface water, and the presence of water held by capillary forces in very small pores between silt and clay size mineral grains. Moreover, SEM images of ion-beam-milled samples reveal a separate nano-porosity system contained within the organic matter, and the gas may be largely contained in these organic pores.

The use of high-vertical-resolution standard logs and borehole image logs enhances the interpretation of vertically heterogenous shale-gas

formations. It is important to keep in mind that kerogen occupies a much larger volume percent (vol%) than is indicated by the TOC weight percent (wt%); this is because of the low grain density of the organic matter (typically 1.1-1.4 g/cc) compared to that of common rock-forming minerals (2.6-2.8 g/cc). Well logs play a critical role in characterizing and quantifying shale-gas resources.

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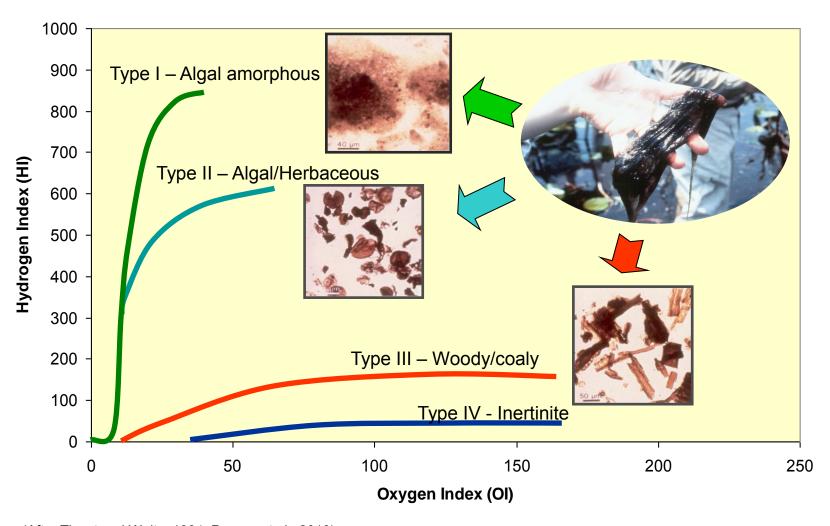
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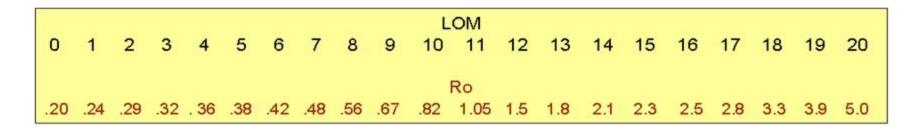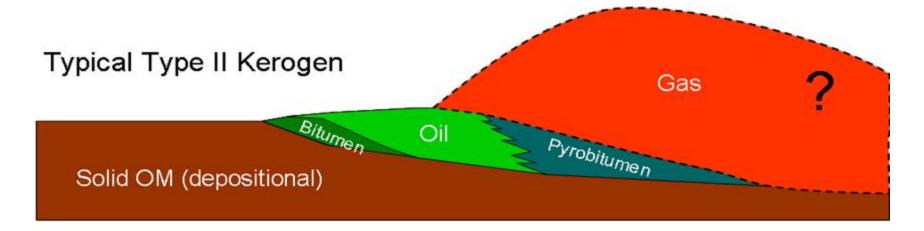Taking on the world's toughest energy challenges.™

Organic Matter Type

(After Tissot and Welte, 1984; Passey et al., 2010)
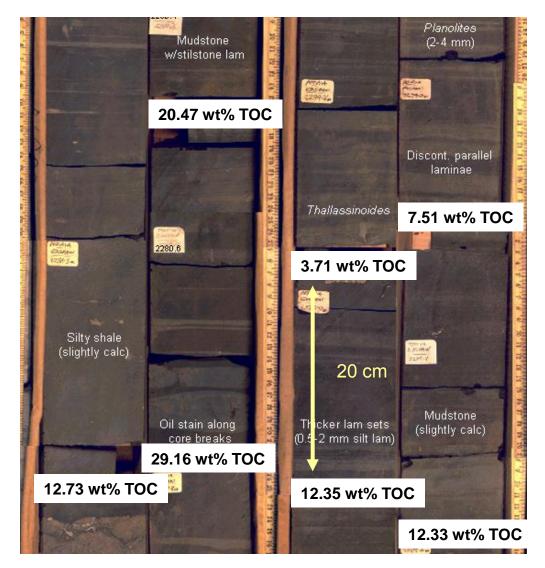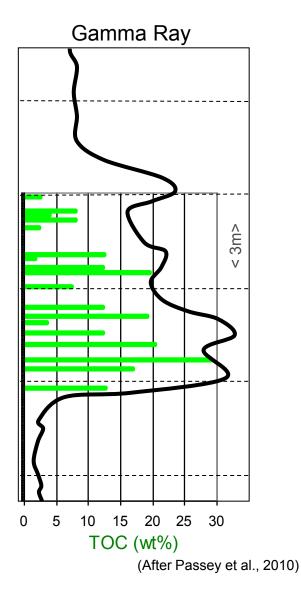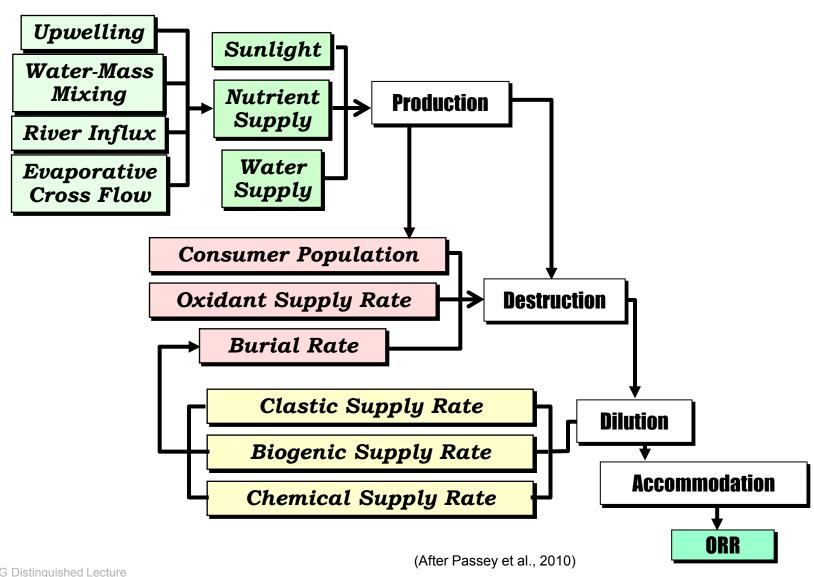
Maturity (LOM/Ro) – Type II Kerogen and Coal Rank

(After Passey et al., 2010)

20.47 wt% TOC

7.51 wt% TOC

3.71 wt% TOC

20 cm

29.16 wt% TOC

12.73 wt% TOC

12.35 wt% TOC

12.33 wt% TOC

Mudstone w/stilstone lam

Planolites (2-4 mm)

Discont. parallel laminae

Thallassinoides

Silty shale (slightly calc)

Oil stain along core breaks

Thicker lam sets (0.5-2 mm silt lam)

Mudstone (slightly calc)

2280.6

Gamma Ray

< 3m >

0   5   10   15   20   25   30

TOC (wt%)

(After Passey et al., 2010)
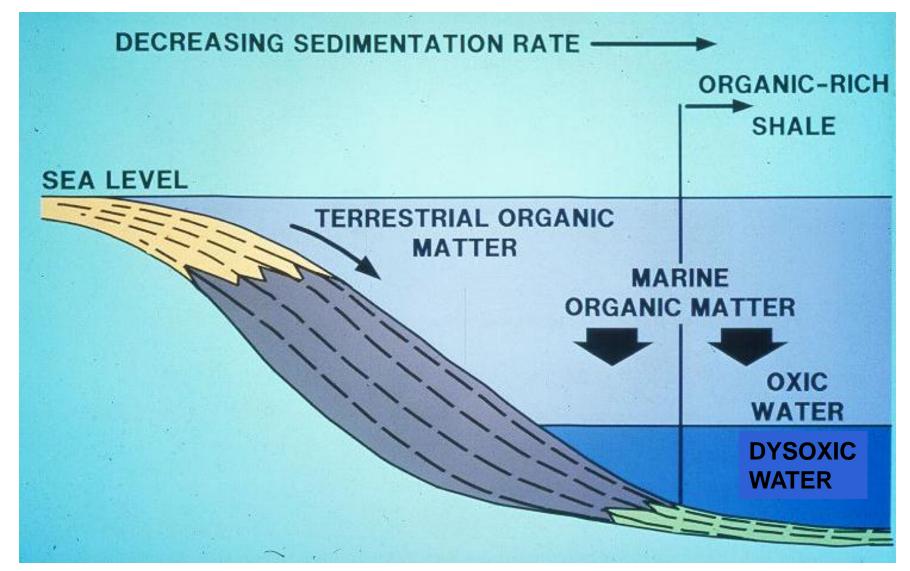
Controls On Organic-Richness

(After Passey et al., 2010)
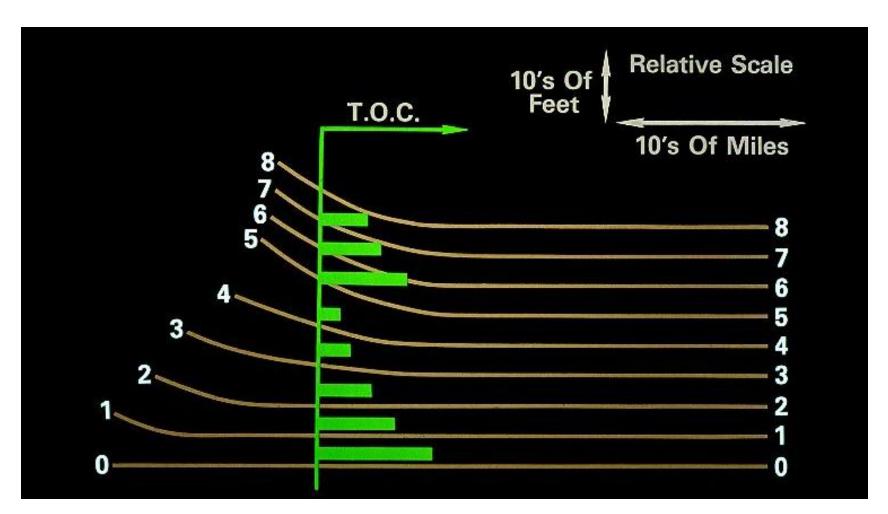
Simple Model for Marine Organic Enrichment

DECREASING SEDIMENTATION RATE →

ORGANIC-RICH SHALE

SEA LEVEL

TERRESTRIAL ORGANIC MATTER

MARINE ORGANIC MATTER

OXIC WATER

DYSOXIC WATER

(After Creaney and Passey, 1993)
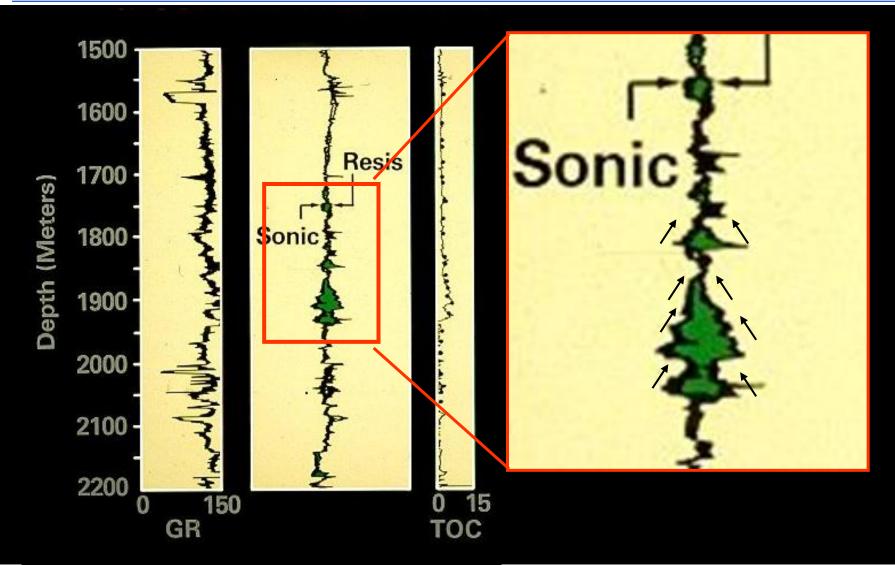
Stacked TOC Triangles (2 Parasequences)

(After Creaney and Passey, 1993)

Vertical Variation in TOC from Well Log Response

(After Creaney and Passey, 1993)
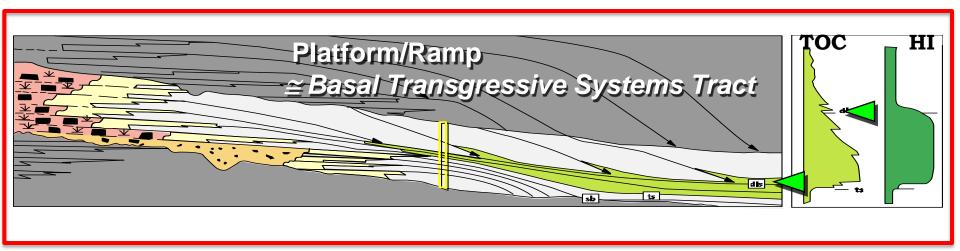
Marine Source Rock Settings

TOC   **HI**

Constructional Shelf Margin
≃ Maximum Transgression (uTST-lHST)

Platform/Ramp
≃ Basal Transgressive Systems Tract

(After Bohacs et al., 2005; Passey et al., 2010)
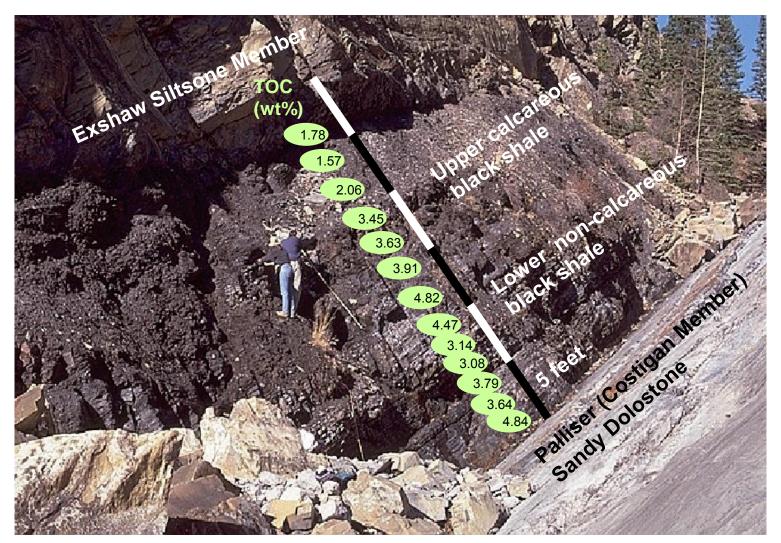
TOC/Parasequence Stacking in Outcrop

TOC (wt%)

1.78
1.57
2.06
3.45
3.63
3.91
4.82
4.47
3.14
3.08
3.79
3.64
4.84

Exshaw Siltsone Member

Upper calcareous black shale

Lower non-calcareous black shale

5 feet

Palliser (Costigan Member) Sandy Dolostone

(After Passey et al., 2010)
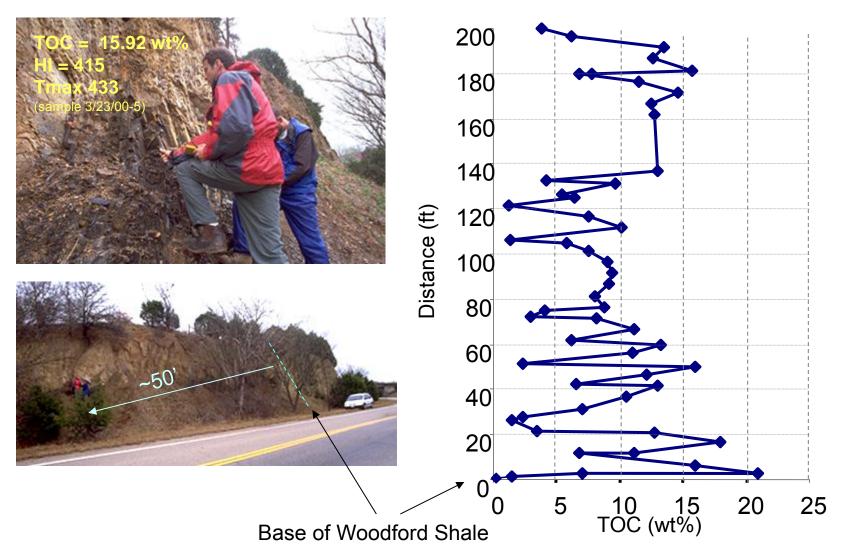
Turner Falls Roadcut (Lower Woodford)

Off US 77 south of Exit 51 (I-35)

(N 34° 26.675' W 97° 7.814')

TOC = 15.92 wt%
HI = 415
Tmax 433
(sample 3/23/00-5)

~50'

Base of Woodford Shale
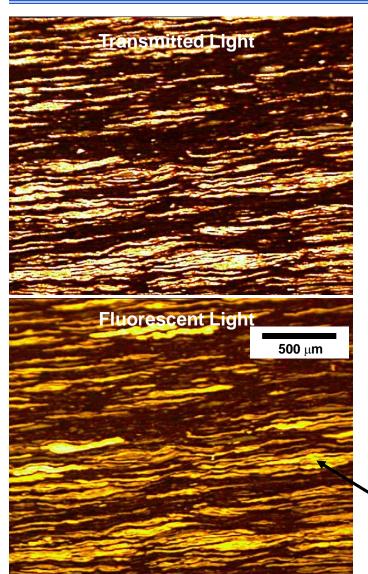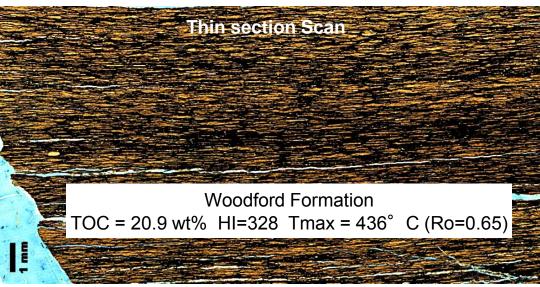
(Includes data from Lo and Bohacs, 1990, pers. comm.)
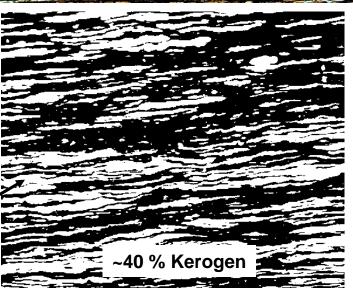
Woodford Shale –
20 wt% TOC → 40 vol% Kerogen

Transmitted Light

Thin section Scan

Woodford Formation
TOC = 20.9 wt%   HI=328   Tmax = 436° C (Ro=0.65)

1 mm

Fluorescent Light

500 μm

Apply threshold
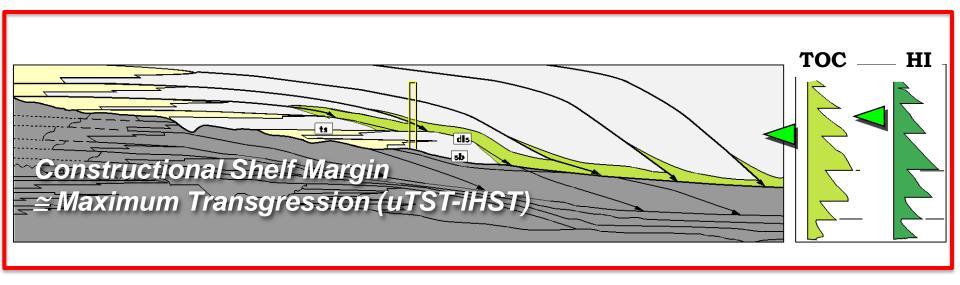
Fluorescing
kerogen
(Tasmanites
cysts of
marine algae)

~40 % Kerogen
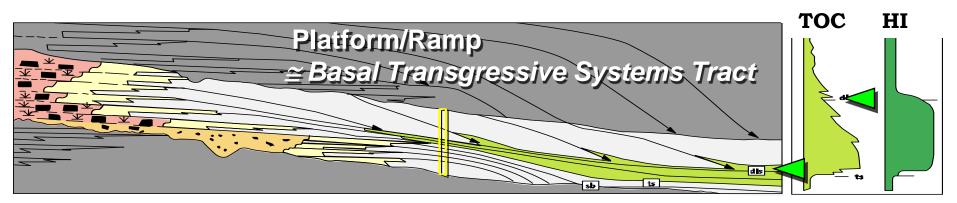
(After Passey et al., 2010)

Marine Source Rock Settings

Constructional Shelf Margin
≅ Maximum Transgression (uTST-lHST)

TOC   HI

Platform/Ramp
≅ Basal Transgressive Systems Tract

TOC   HI

(After Bohacs et al., 2005; Passey et al., 2010)
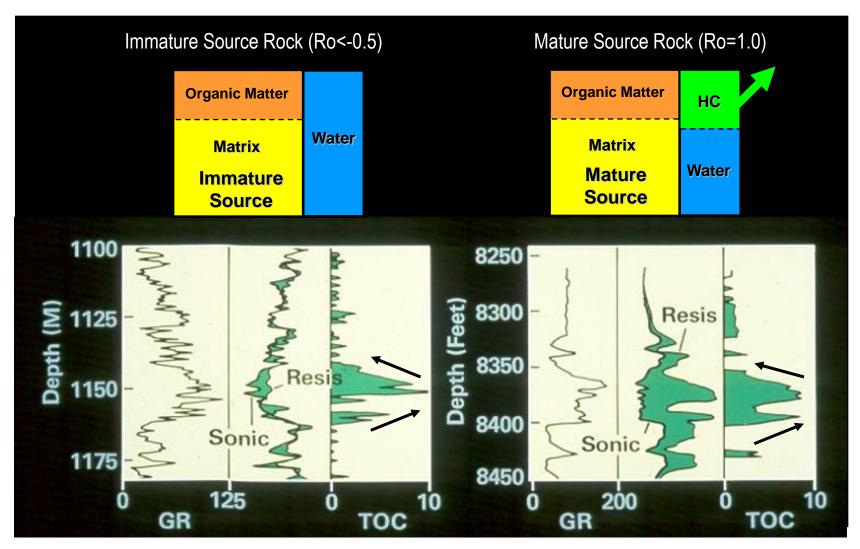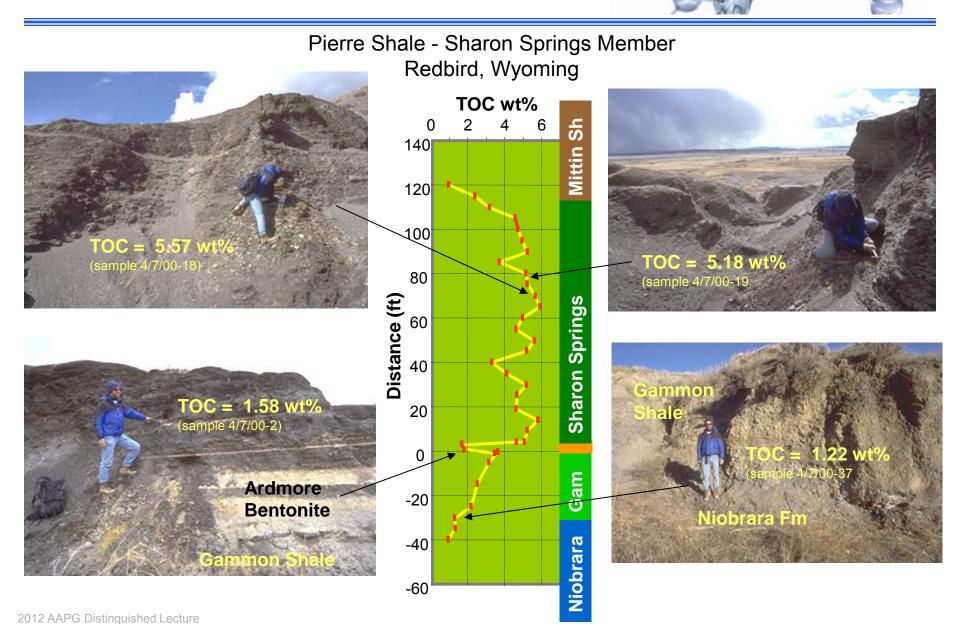
Maturity Effect on Well Log Response in Organic-rich Intervals

Immature Source Rock (Ro<-0.5)

Mature Source Rock (Ro=1.0)

(After Passey et al., 1990)
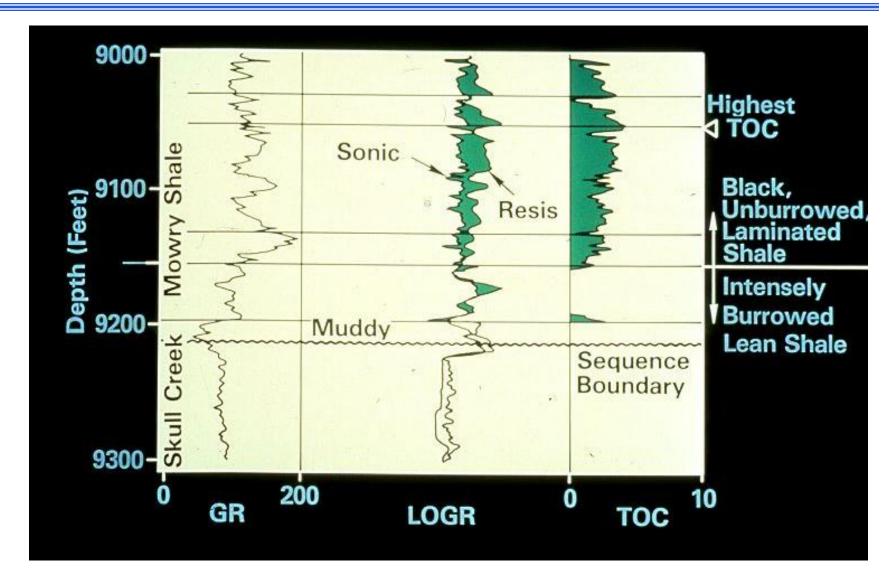
Systematic vertical variation in TOC

Pierre Shale - Sharon Springs Member
Redbird, Wyoming

TOC = 5.57 wt%
(sample 4/7/00-18)

TOC = 5.18 wt%
(sample 4/7/00-19

TOC = 1.58 wt%
(sample 4/7/00-2)

Ardmore
Bentonite

Gammon Shale

Gammon
Shale

TOC = 1.22 wt%
(sample 4/7/00-37)

Niobrara Fm
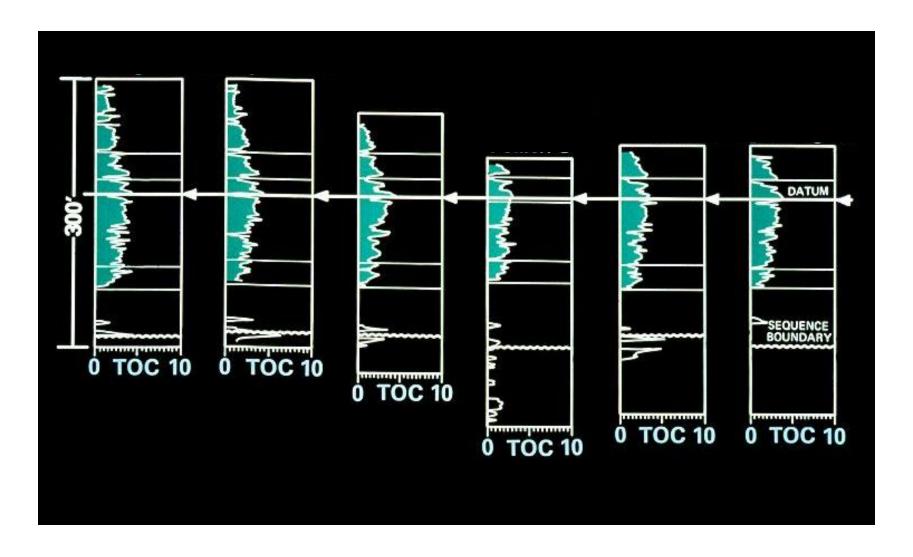
Stacking Patterns within Mowry Shale

(After Creaney and Passey, 1993)
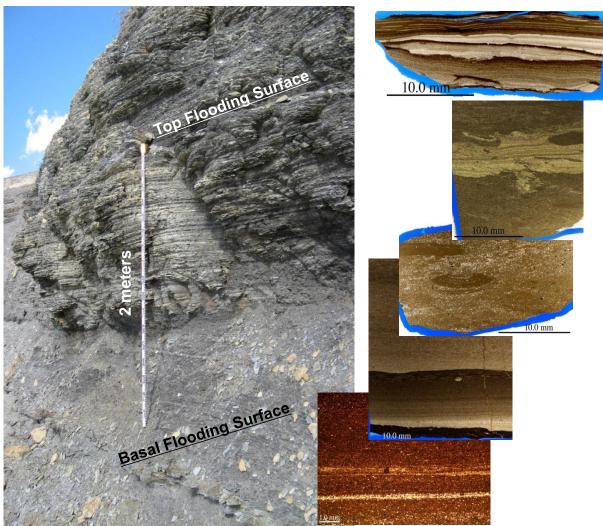
Correlation of TOC Maxima (and Parasequences) Mowry
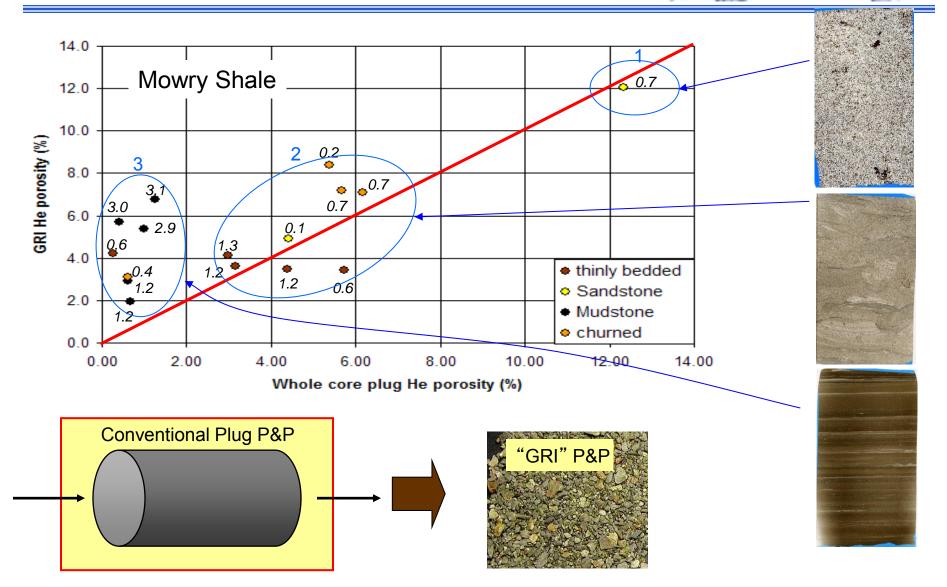
Parasequence Lithofacies Stacking Pattern

Top Flooding Surface

2 meters

Basal Flooding Surface

10.0 mm

10.0 mm

10.0 mm

10.0 mm

10.0 mm

(After Passey et al., 2010)
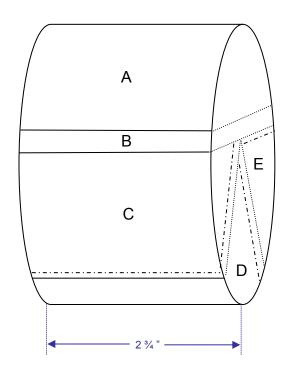
Analytical Methods - GRI Crushed Rock vs Plug Porosity

Mowry Shale

Cluster labels: 1, 2, 3

Data point values: 0.7, 0.2, 0.7, 0.7, 3.1, 3.0, 2.9, 0.1, 0.6, 1.3, 0.4, 1.2, 1.2, 1.2, 0.6

Legend:
- thinly bedded
- Sandstone
- Mudstone
- churned

Axes: GRI He porosity (%) vs Whole core plug He porosity (%)

Conventional Plug P&P

"GRI" P&P

(Courtesy Rene Jonk reported in Spears et al, 2011)
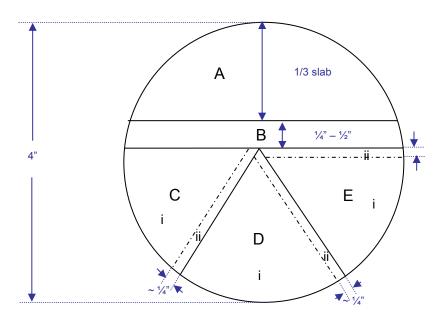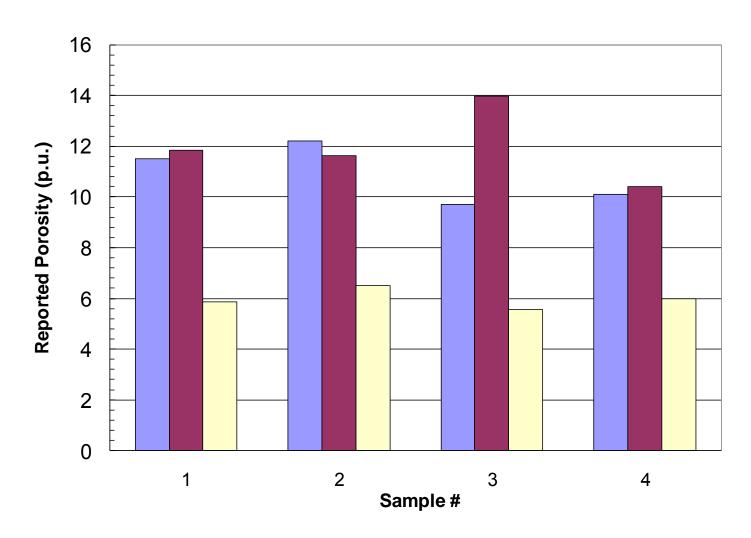
- **Preserved shale samples were used in the studies**
- **Parts of same sample were sent to 3-5 different commercial laboratories for bulk and grain densities, GRI porosity, GRI perm and saturation measurements**
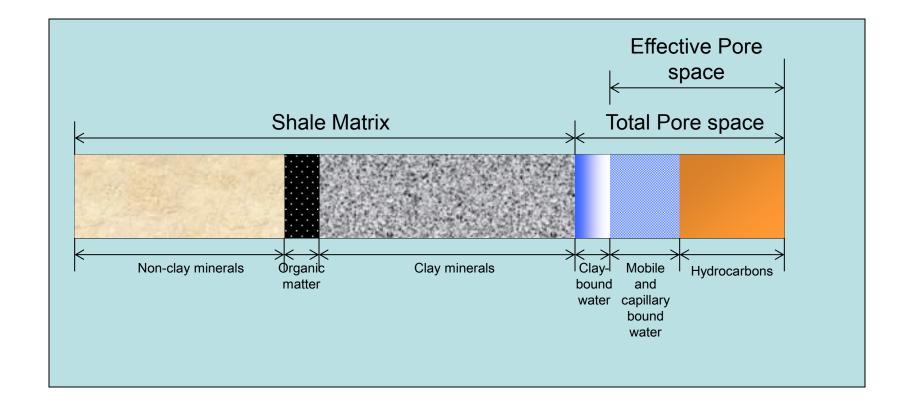
Comparison of "Reported Porosity" from Different Labs

(After Passey et al., 2010)

Definition of Total & Effective Porosity for Shale-gas Reservoirs

(After Passey et al., 2010)
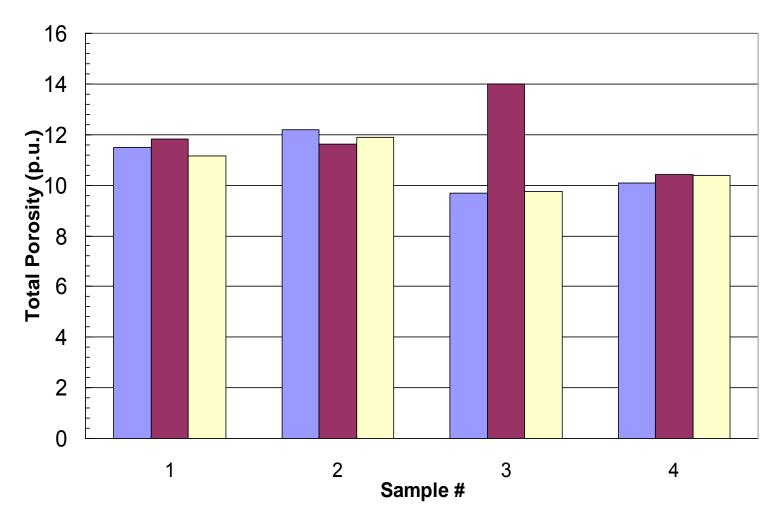
Comparison of "GRI" Total Porosity from Different Labs
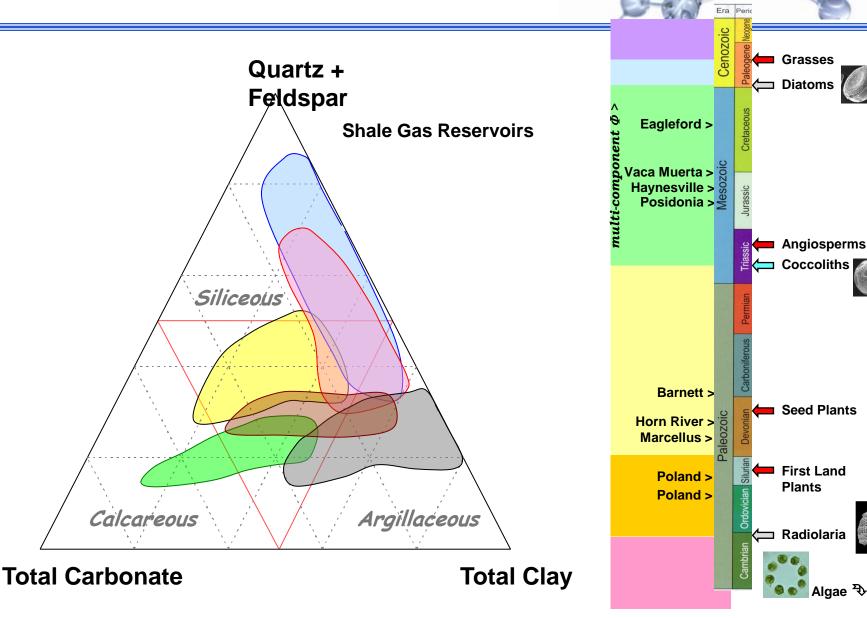
⭐ **Total Porosity Measurements now within ~1p.u.**

Does Rock Composition Matter ?

Quartz + Feldspar

Shale Gas Reservoirs

Siliceous

Calcareous   *Argillaceous*

Total Carbonate   **Total Clay**

multi-component Φ >

Era	Period	
Cenozoic	Neogene	
	Paleogene	← Grasses
		⇐ Diatoms
Mesozoic	Cretaceous	**Eagleford >**
		Vaca Muerta >
	Jurassic	**Haynesville >**
		Posidonia >
	Triassic	← Angiosperms
		⇐ Coccoliths
Paleozoic	Permian	
	Carboniferous	
		Barnett >
	Devonian	← Seed Plants
		Horn River >
		Marcellus >
	Silurian	← First Land Plants
		Poland >
	Ordovician	**Poland >**
		⇐ Radiolaria
	Cambrian	
		Algae

Key Parameters for Shale Gas Sample Evaluation

- **Total Organic Carbon (TOC**) wt%
- **Maturity** (Ro %) –
    - -Vitrinite Reflectance Equivalent
    - - Biomarkers – maturity indicator
    - - Carbon Isotopes – related to maturity
- Geo**chemical parameters** (HC type and quality)
    - - Fluid inclusions
    - - Wetness (C2-C5)
    - - API Gravity (tight oil)
- **Total Porosity** – crushed rock total porosity method
- **Water Saturation** (total)
- **Adsorbed gas volume** (scf/ton)
- **Free gas** – typically calculated from logs
- **Permeability** – steady state flow recommended
- **Microscopy**
    - - Thin Sections – optical microscopy
    - - Scanning Electron Microscopy (SEM/EDS)
    - - Focus Ion Beam - SEM
- **Lithology/mineralogy**
    - - XRD/XRF
- **Geomechanical Properties** (Young's Modulus, Poisson's ratio)
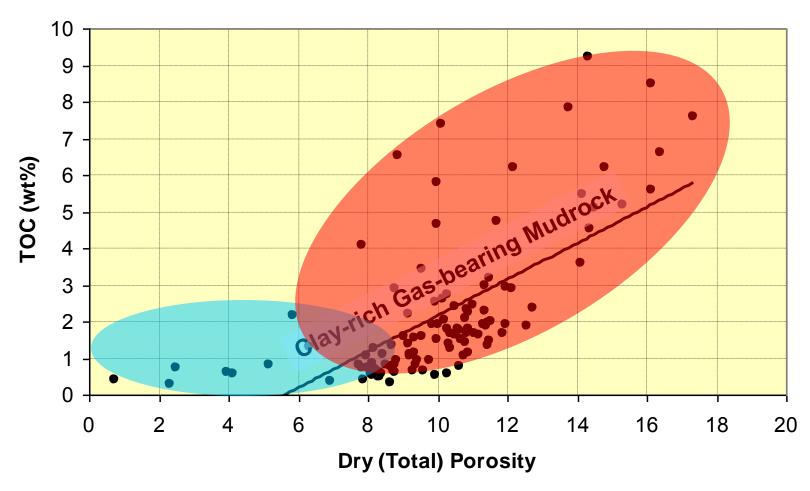
TOC from ΔlogR and Borehole Image Log Response

(After Passey et al., 2010)
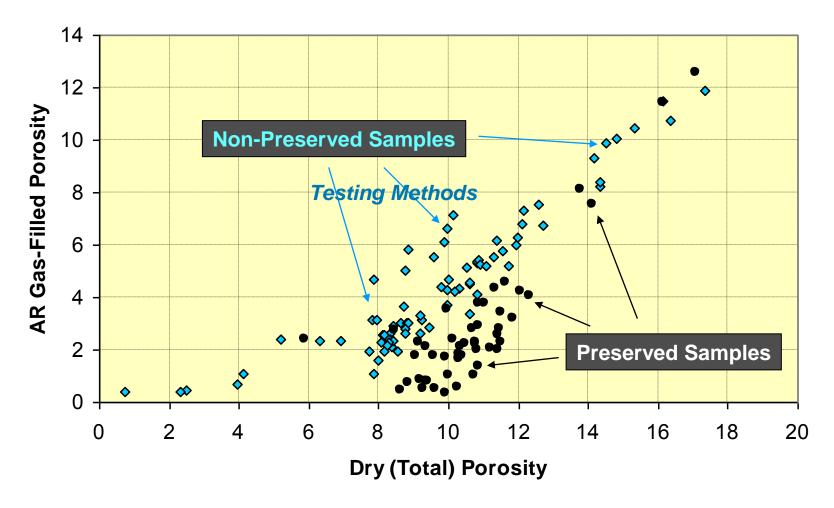
TOC versus Total Porosity in Gas-bearing Mudrocks

Clay-rich Gas-bearing Mudrock

(After Passey et al., 2010)
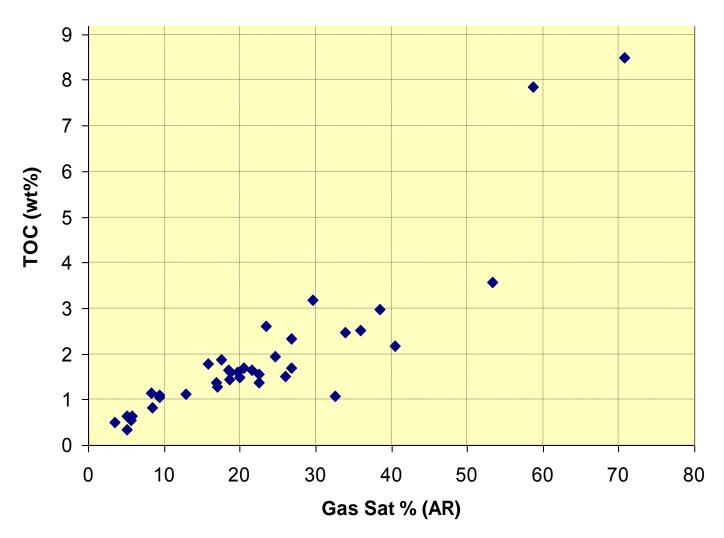
Porosity versus Gas-filled Porosity in Shale-Gas Reservoir

(After Passey et al., 2010)
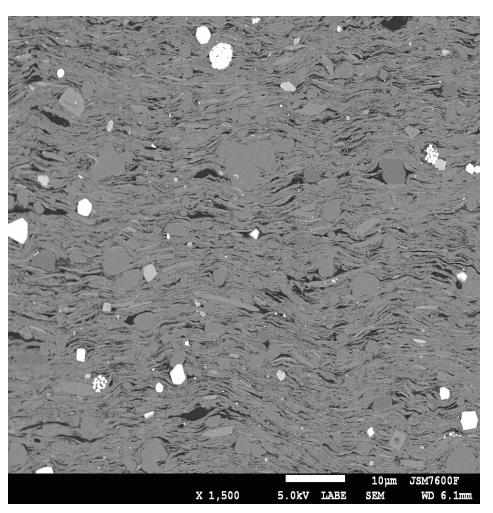
TOC and Sg are Correlated

(After Passey et al., 2010)

Interclay Porosity – Filled with Water
Organic Pores – Filled with Gas
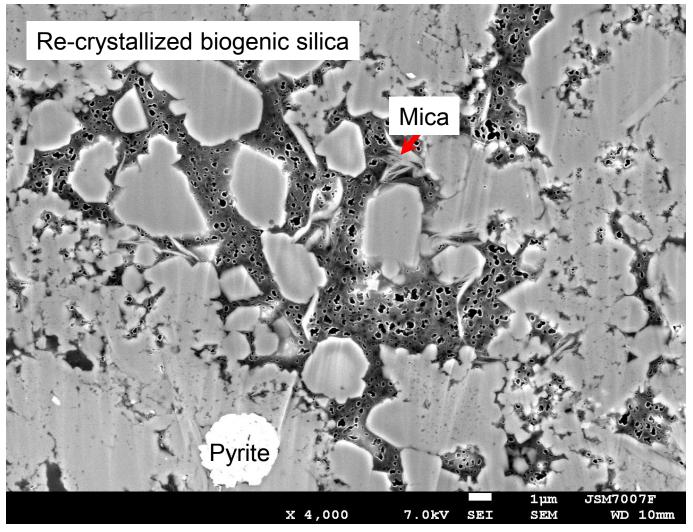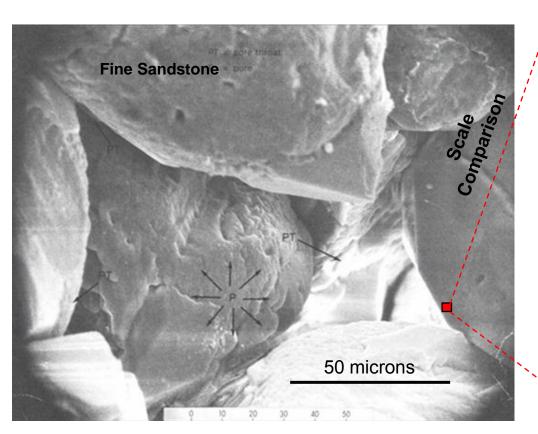
TOC = 5.6 wt%
Ro = 2.2
$\phi_t \cong 15$ p.u. (~ 8 p.u. water)
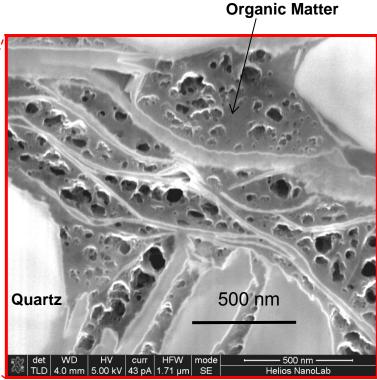
Recrystalized Biogenic Silica and Pores in Organic Matter

Re-crystallized biogenic silica

Mica

Pyrite

X 4,000   7.0kV   SEI   SEM   1µm   JSM7007F   WD 10mm

(After Passey et al., 2010)
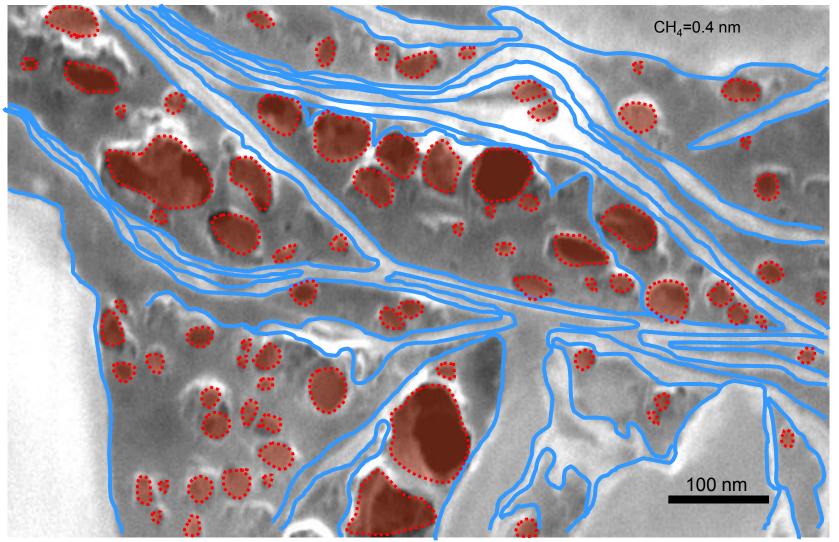
Pore-size Comparison – Fine Sandstone versus Organic-matter

Fine Sandstone

50 microns

Scale Comparison

Organic Matter

Quartz

500 nm

| det | WD | HV | curr | HFW | mode | 500 nm |
| TLD | 4.0 mm | 5.00 kV | 43 pA | 1.71 µm | SE | Helios NanoLab |

(After Passey et al., 2010)

Hypothetical Distribution of Gas and Water

CH$_4$=0.4 nm

100 nm

(After Passey et al., 2010)
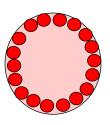
Adsorbed Gas Fraction Higher in Small Pores (Surface to Volume)

40 nm Pore
S/V = 0.15

Free Gas > (Adsorbed)

4 nm Pore
S/V = 1.5
Adsorbed ~ Free Gas
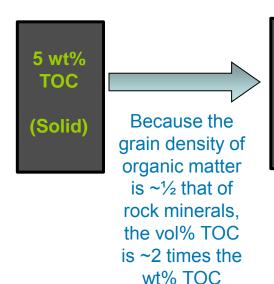
2 nm Pore
S/V = 3.1
Adsorbed > (Free Gas)

TOC wt% ≠ TOC vol%
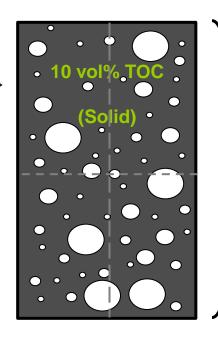
For a "Typical" Shale Gas the current TOC = 5 wt%

5 wt%
TOC

(Solid)

Because the grain density of organic matter is ~½ that of rock minerals, the vol% TOC is ~2 times the wt% TOC
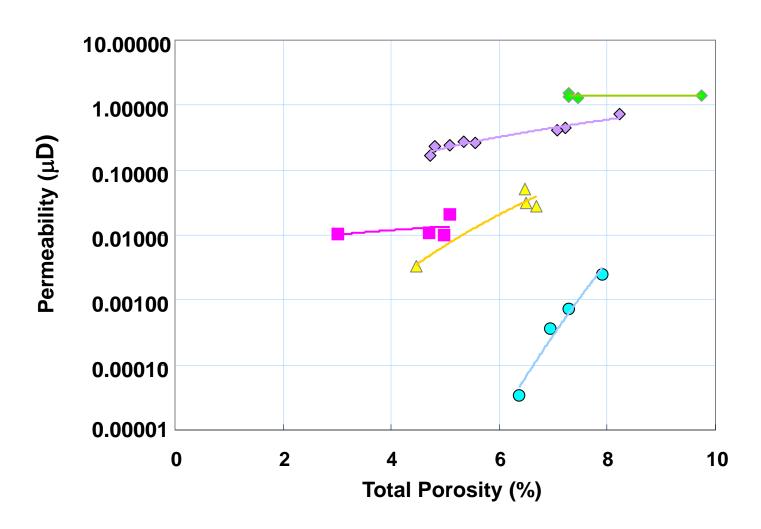
10 vol% TOC

(Solid)

If 50 vol% of the <u>original</u> organic matter volume is now pores, the volume impacted by the current 5 wt% TOC is approximately 20 vol% of the rock.

10 vol% TOC

(Solid)
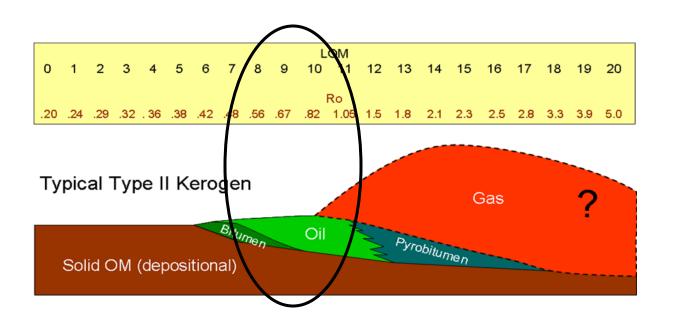
~20 volume % of the rock

(After Passey et al., 2010)

5-Lab Comparison – Porosity getting better but what about Permeability?
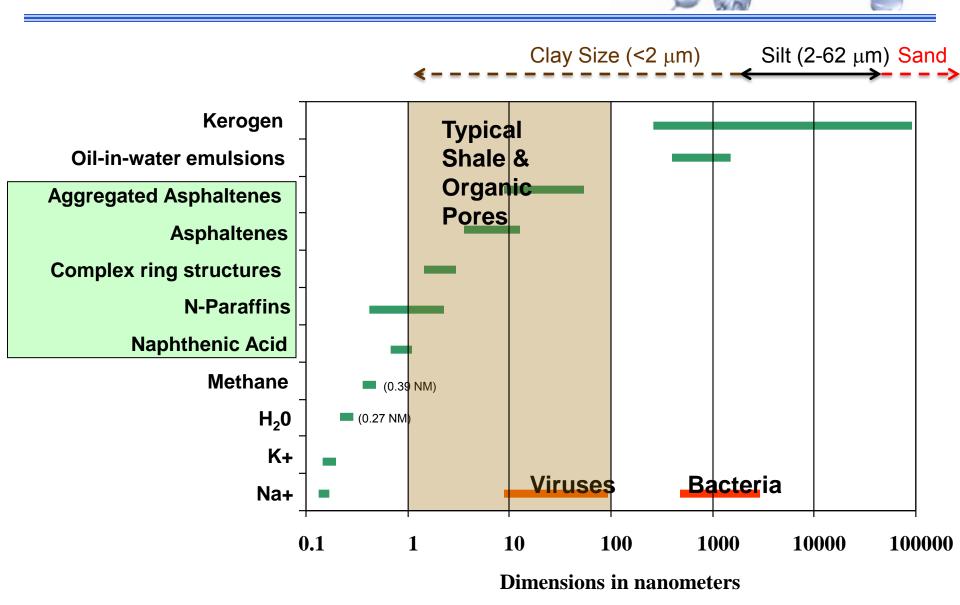
Where is the oil in "Shale Oil"?
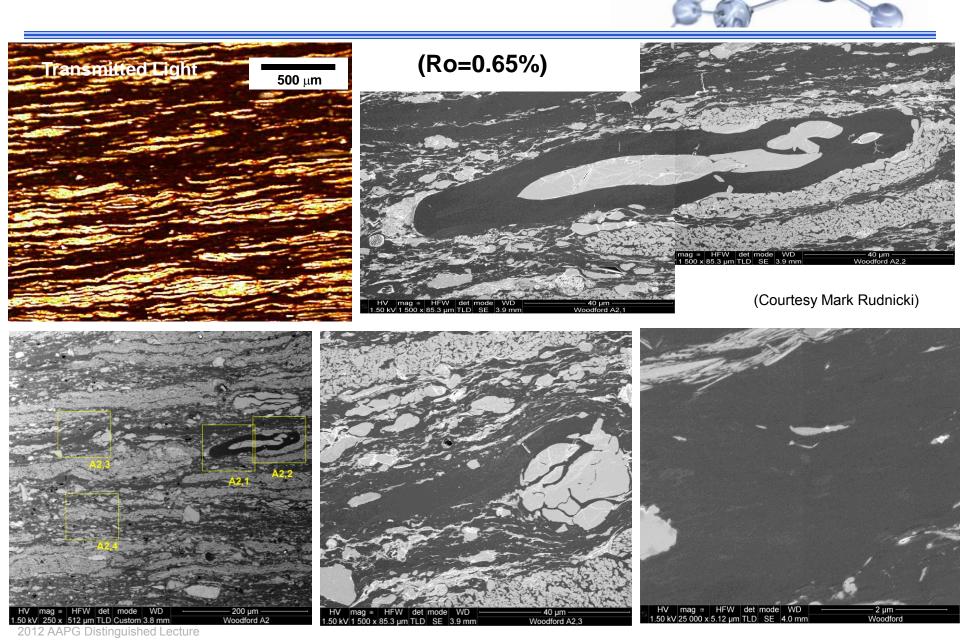
Molecular Sizes and Organic Pores

Clay Size (<2 μm) Silt (2-62 μm) Sand

- Kerogen
- Oil-in-water emulsions
- Aggregated Asphaltenes
- Asphaltenes
- Complex ring structures
- N-Paraffins
- Naphthenic Acid
- Methane (0.39 NM)
- H_2O (0.27 NM)
- K+
- Na+

Typical Shale & Organic Pores

Viruses **Bacteria**

0.1   1   10   100   1000   10000   100000

Dimensions in nanometers
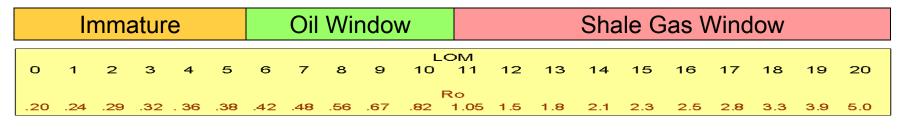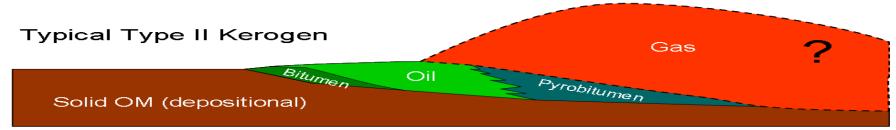
(After Momper, 1978)
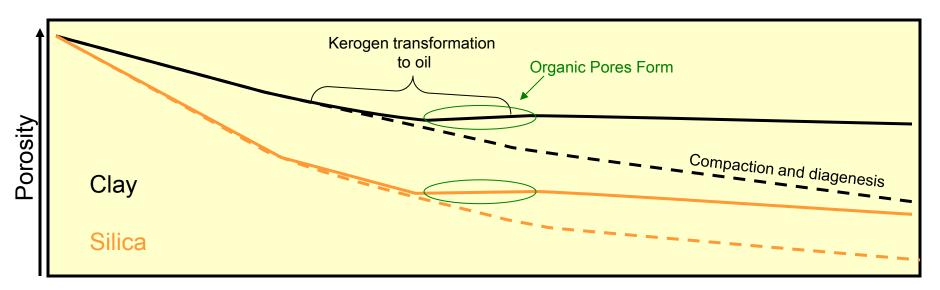
Woodford Shale – 20.9 wt% TOC

Transmitted Light

500 μm

(Ro=0.65%)

(Courtesy Mark Rudnicki)

Porosity Evolution in Organic-rich Rocks

Immature	Oil Window	Shale Gas Window

LOM

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

Ro

.20	.24	.29	.32	.36	.38	.42	.48	.56	.67	.82	1.05	1.5	1.8	2.1	2.3	2.5	2.8	3.3	3.9	5.0

Typical Type II Kerogen

Bitumen

Oil

Gas

?

Pyrobitumen

Solid OM (depositional)

Kerogen transformation to oil

Organic Pores Form

Porosity

Compaction and diagenesis

Clay

Silica

Shale Oil (Ro 0.5-1.0)

(Gale et al. 2007)

5 cm

2 mm

500 μm

kerogen

Carbonate

clay

kerogen

silt

clay

kerogen

Summary

- Shale-gas reservoirs are overmature oil-prone source rocks

- The parasequence is the fundamental building block of shale gas reservoirs

- Porosity, TOC, and gas content are all positively correlated for shale-gas reservoirs Ro 1-3+)

- Free gas likely to be largely in organic-matter porosity

- Gas-filled porosity (BVG) is better characterization term than Sg

- The porosity system for fluids in organic-rich systems evolves with increasing maturity and is influenced by matrix lithology

For Further Information – SPE 131350