From Oil-Prone Source Rock to Gas-Producing Shale Reservoir – Geologic and Petrophysical Characterization of Shale-Gas Reservoirs

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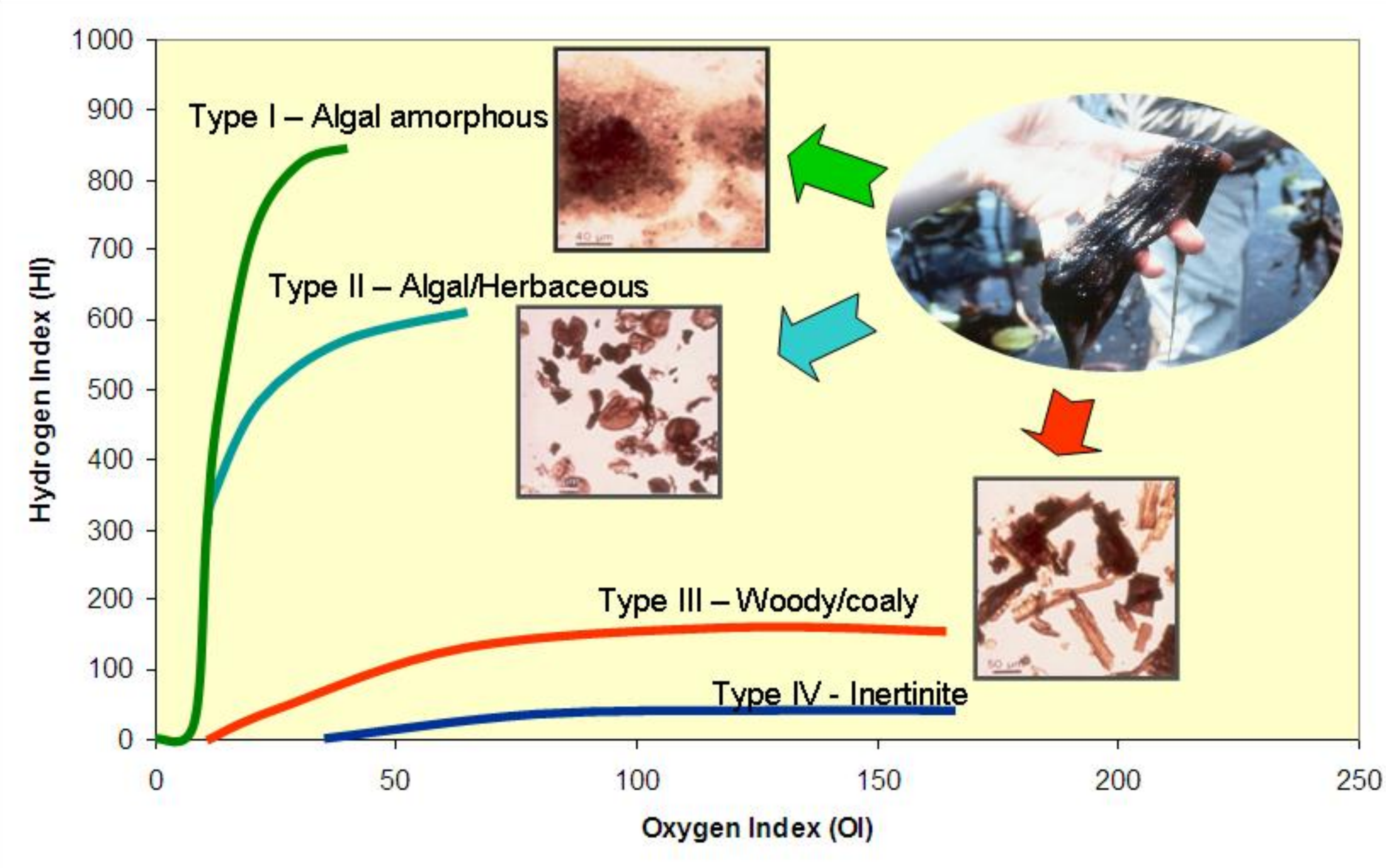
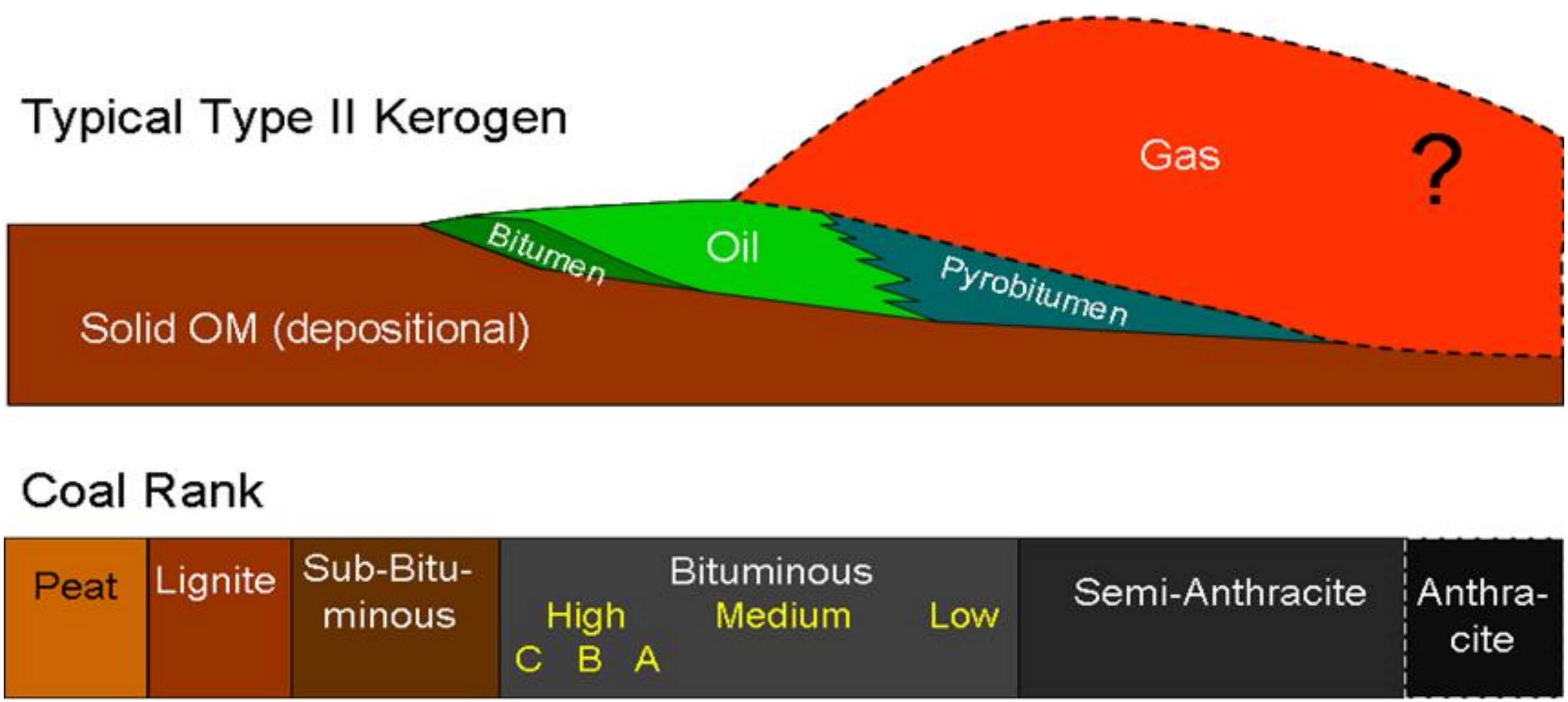
Organic Matter Type

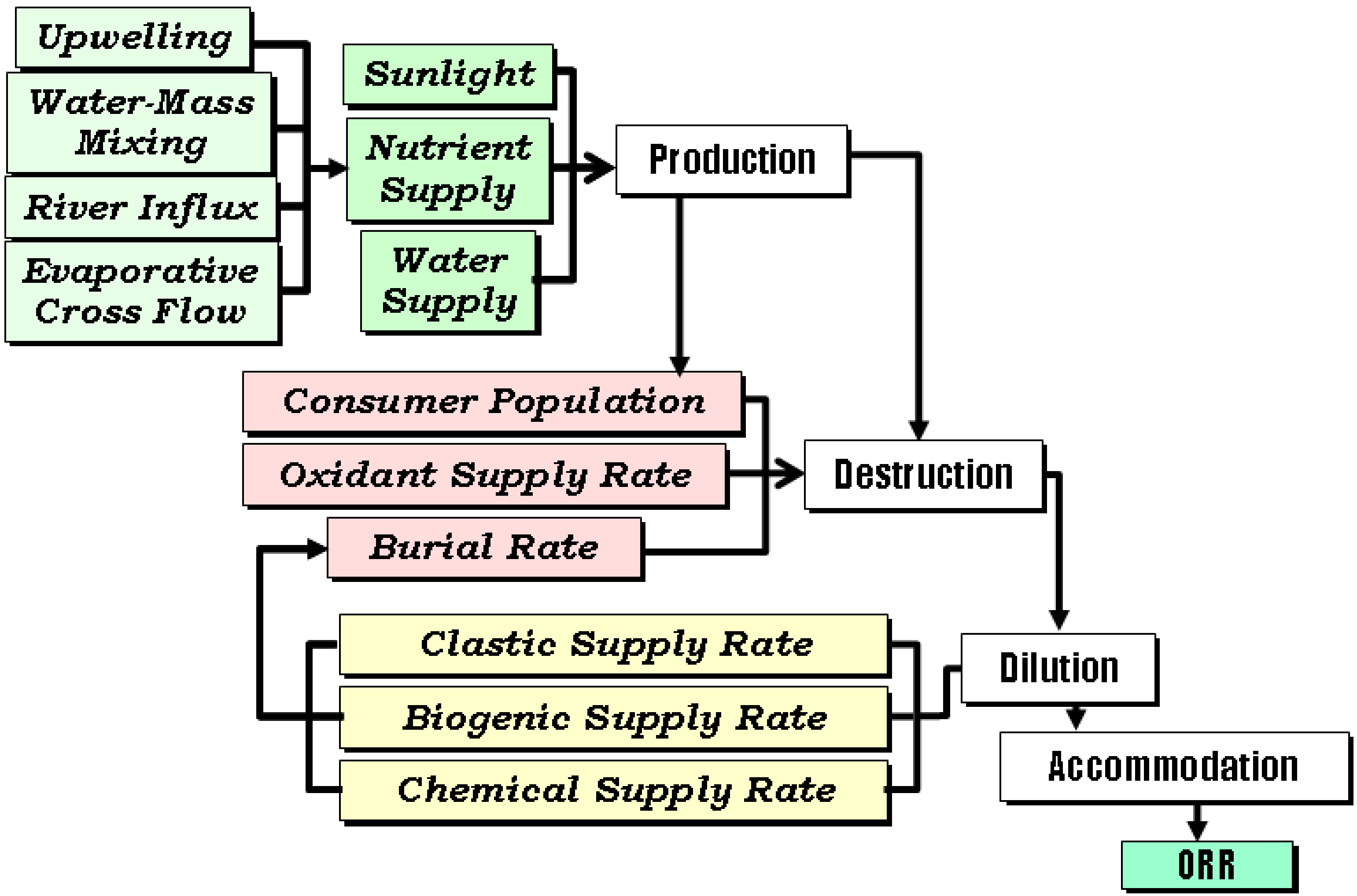


Maturity (LOM/Ro) – Type II Kerogen and Coal Rank

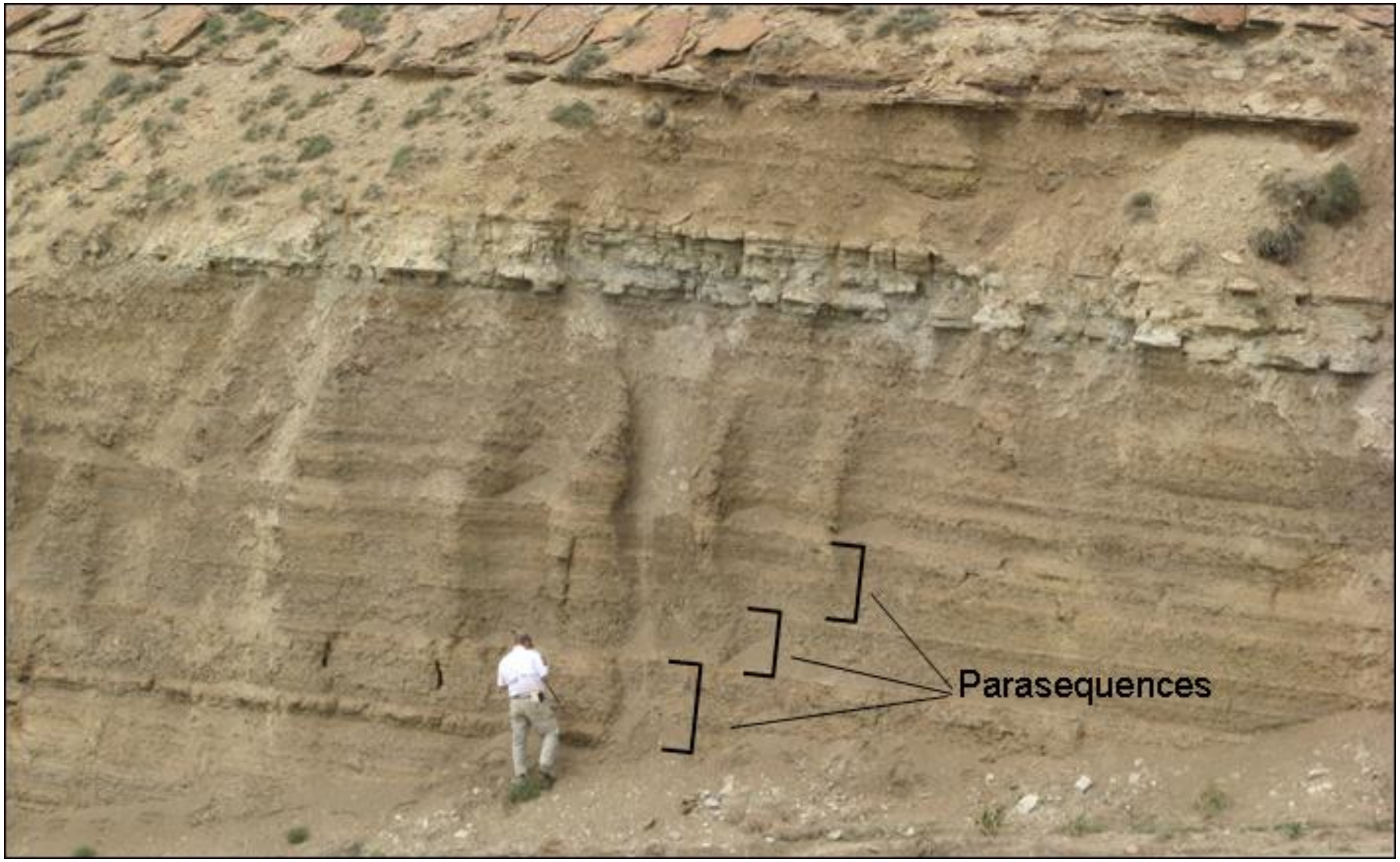
LOM	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Ro	.20	.24	.29	.32	. 36	.38	.42	.48	.56	.67	.82	1.05	1.5	1.8	2.1	2.3	2.5	2.8	3.3	3.9	5.0



Controls On Organic-Richness

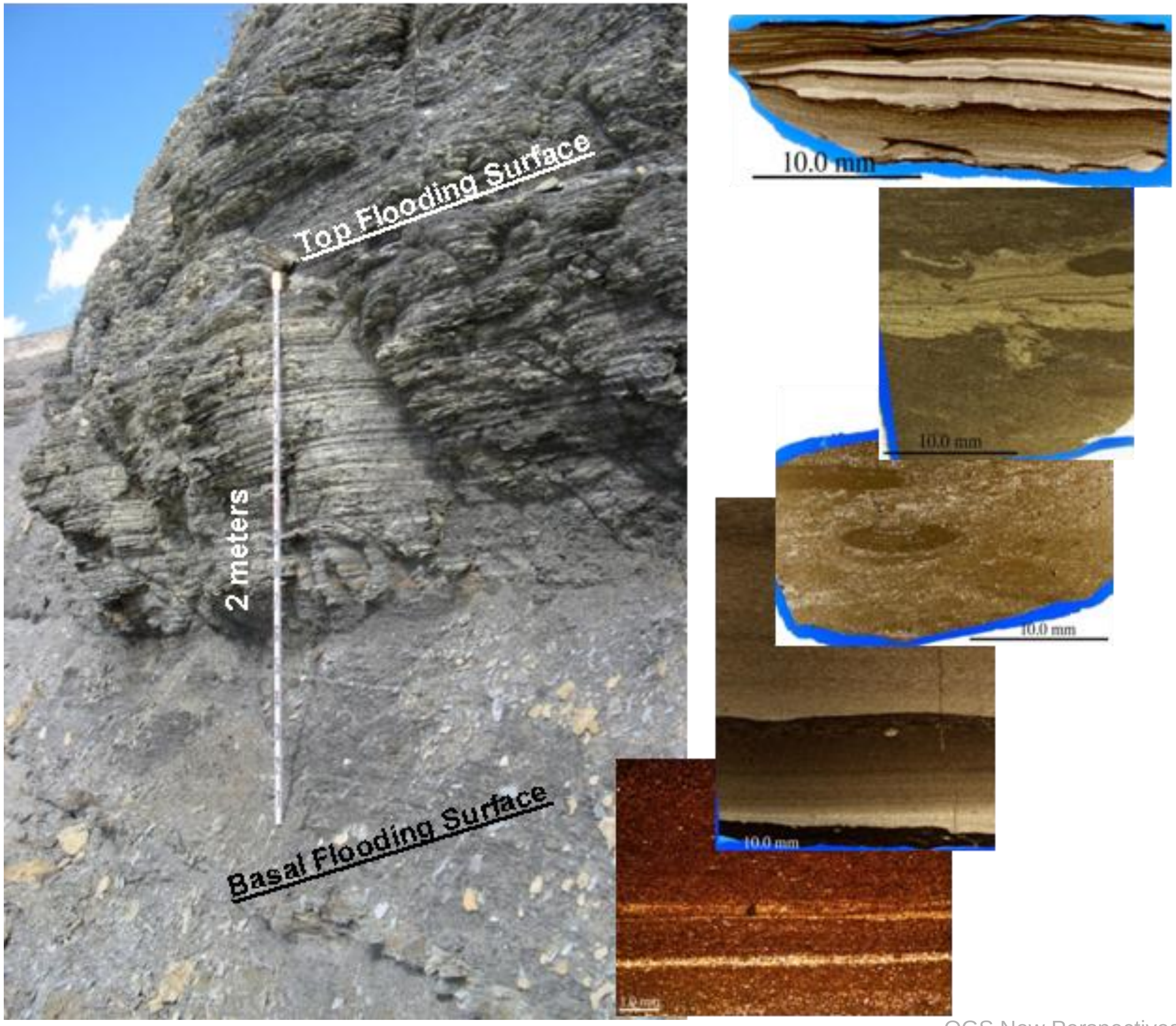


1-2 m thick Parasequences in Mudstones

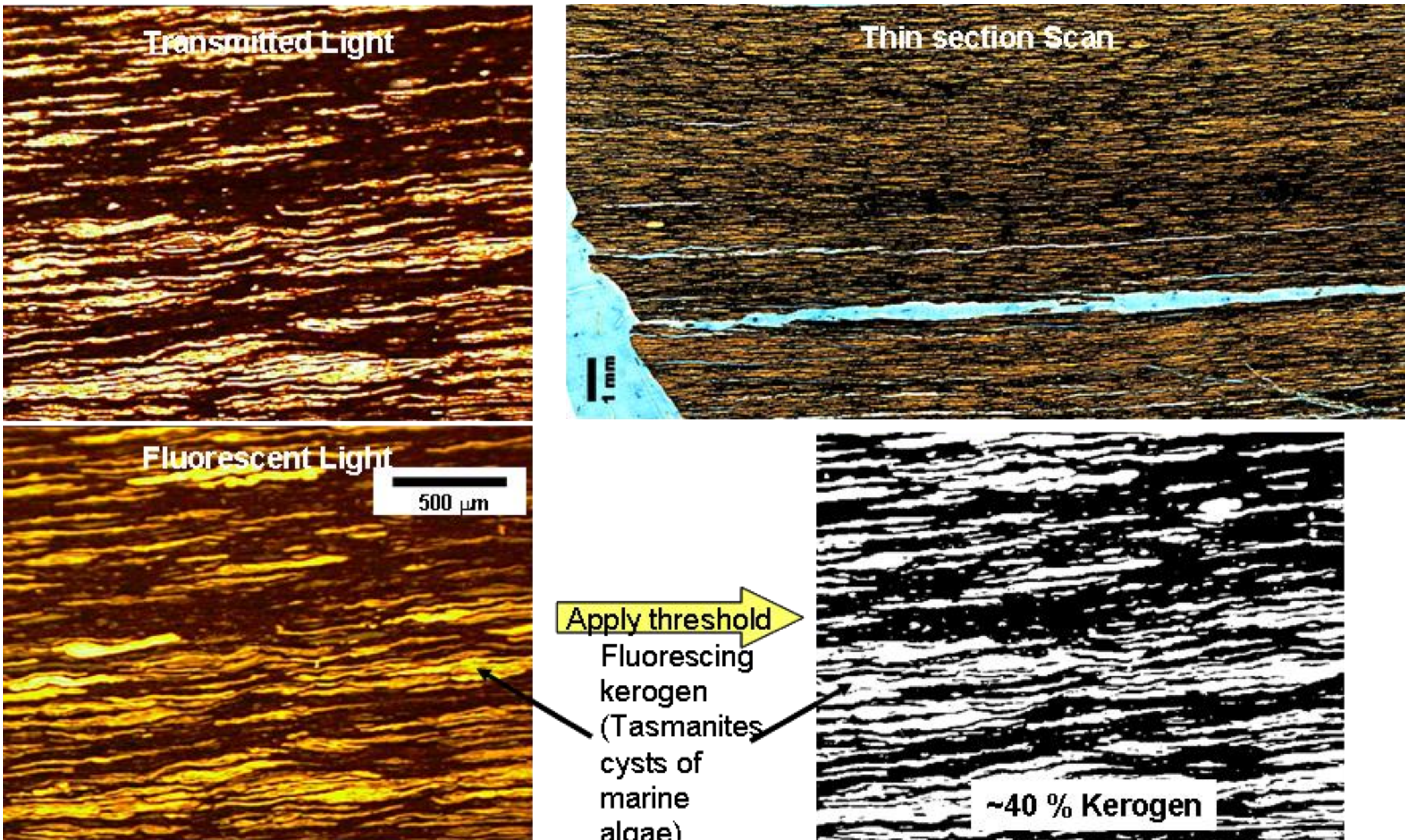


Luman Tongue, Hiawatha Section, Green River Basin, WY

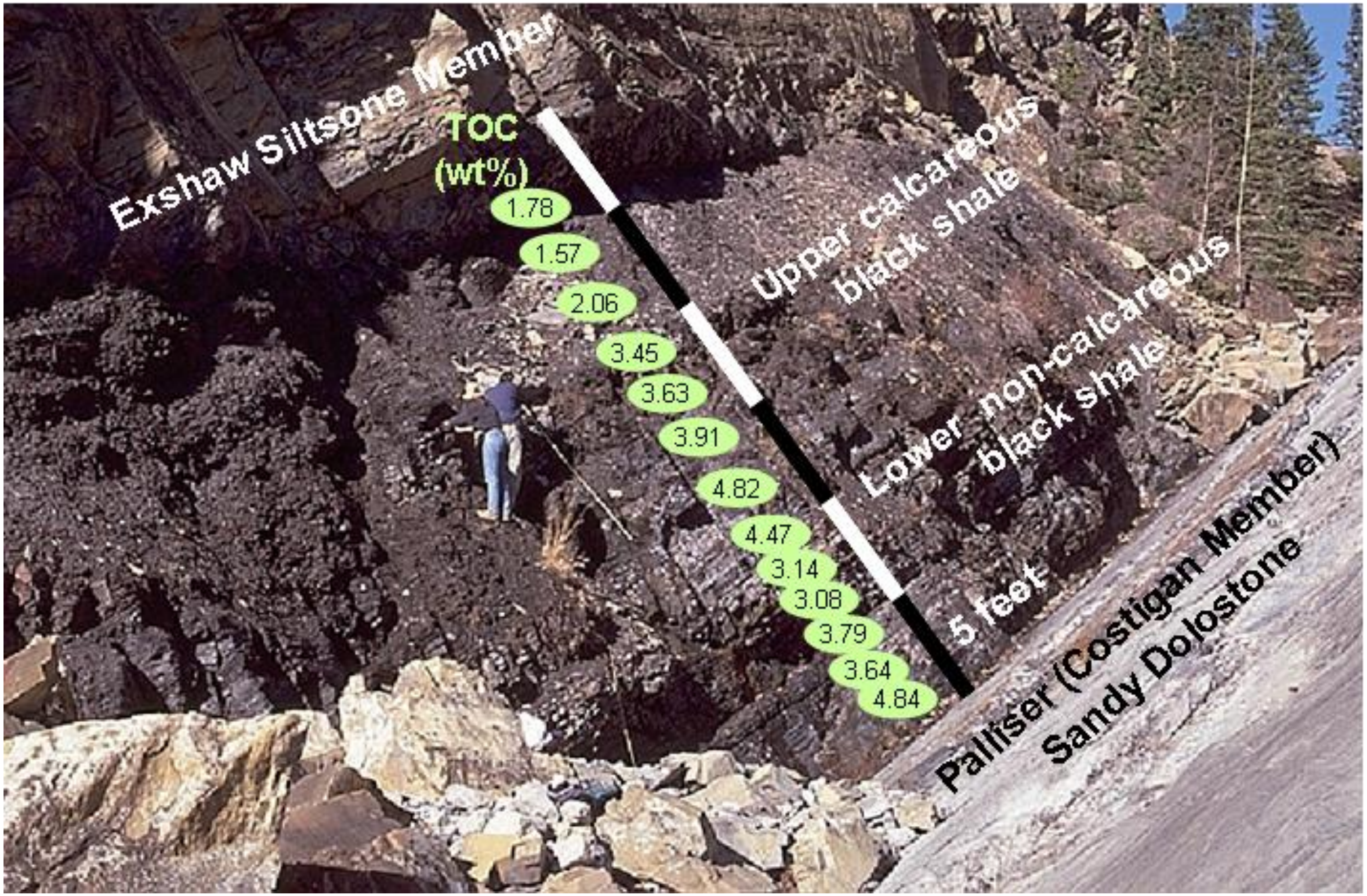
Parasequence Lithofacies Stacking Pattern



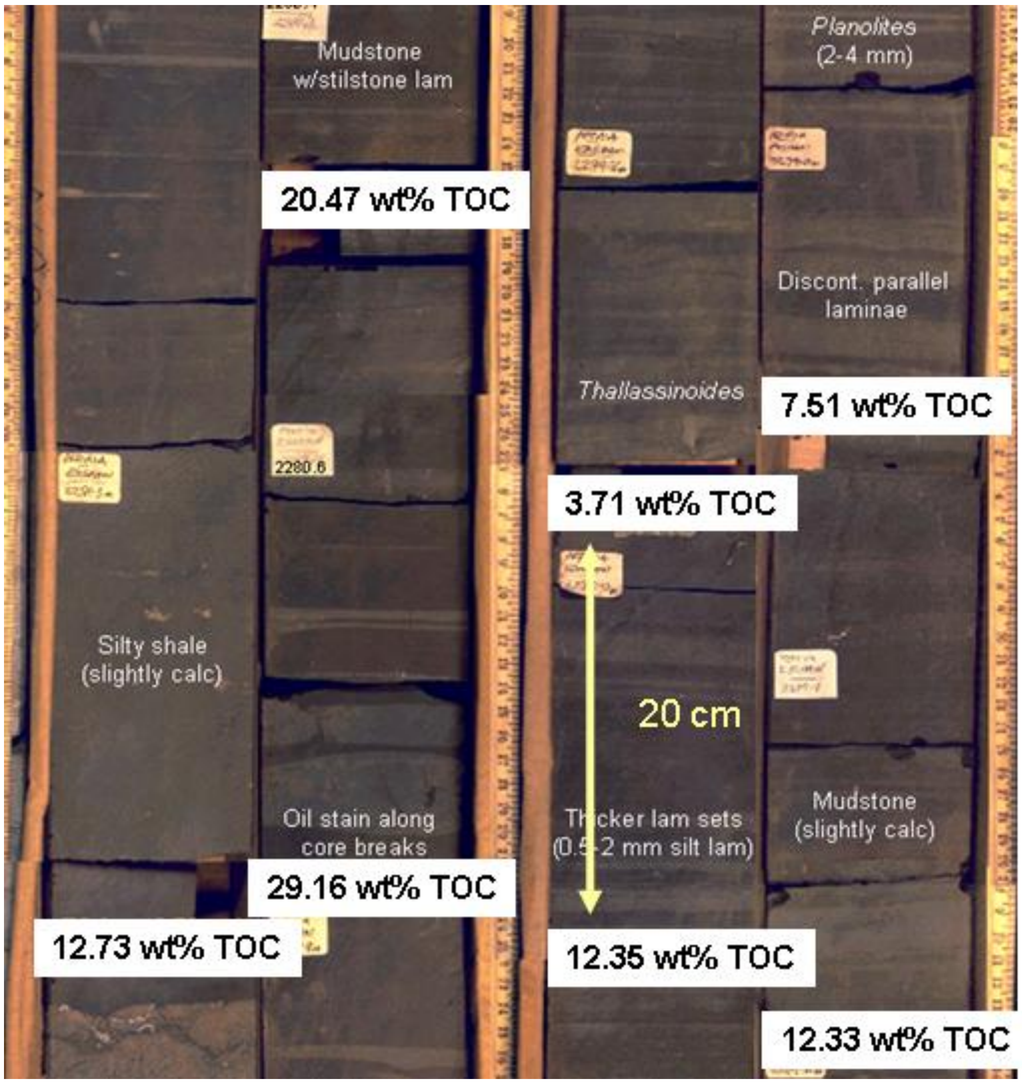
Woodford Shale –
20 wt% TOC → 40 vol% Kerogen

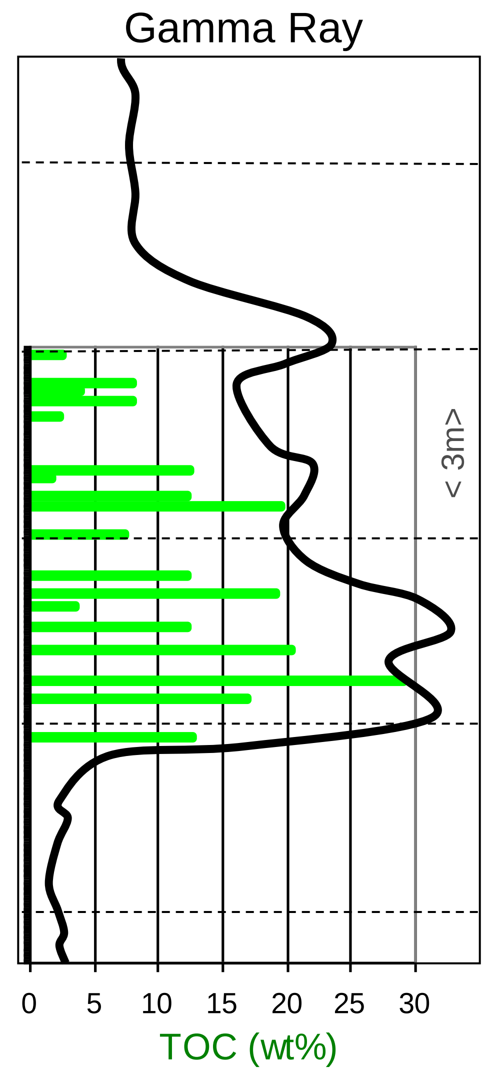


TOC Variablility in Exshaw Formation

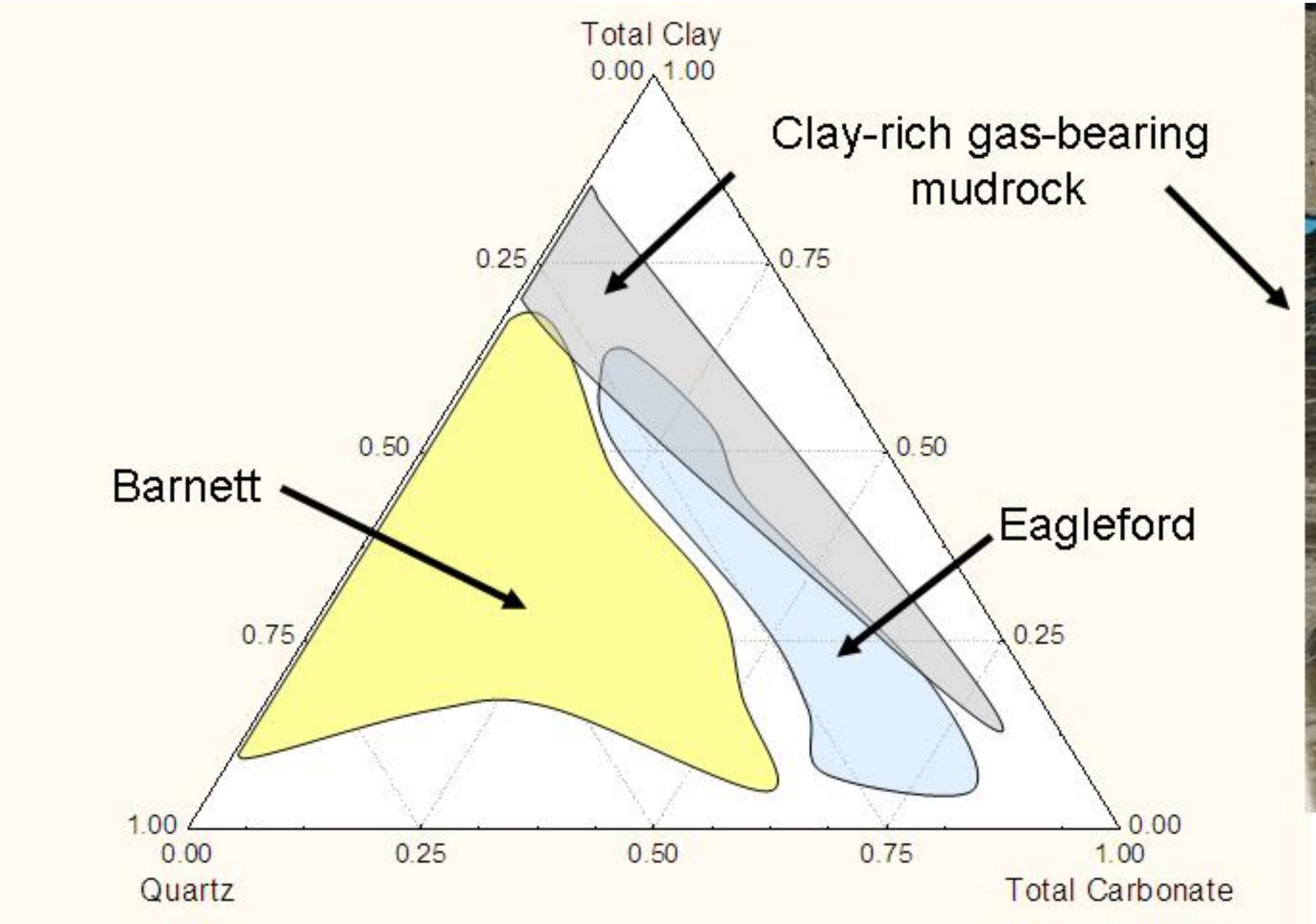


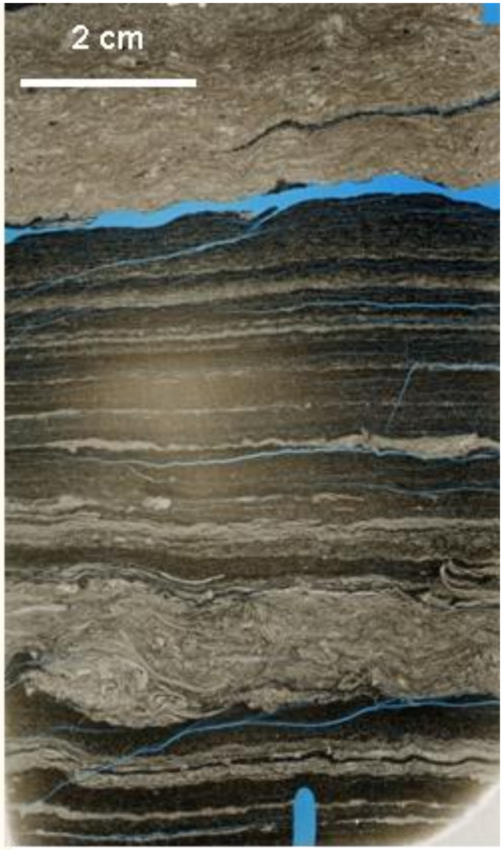
Vertical Variability
Scale of cm to meters



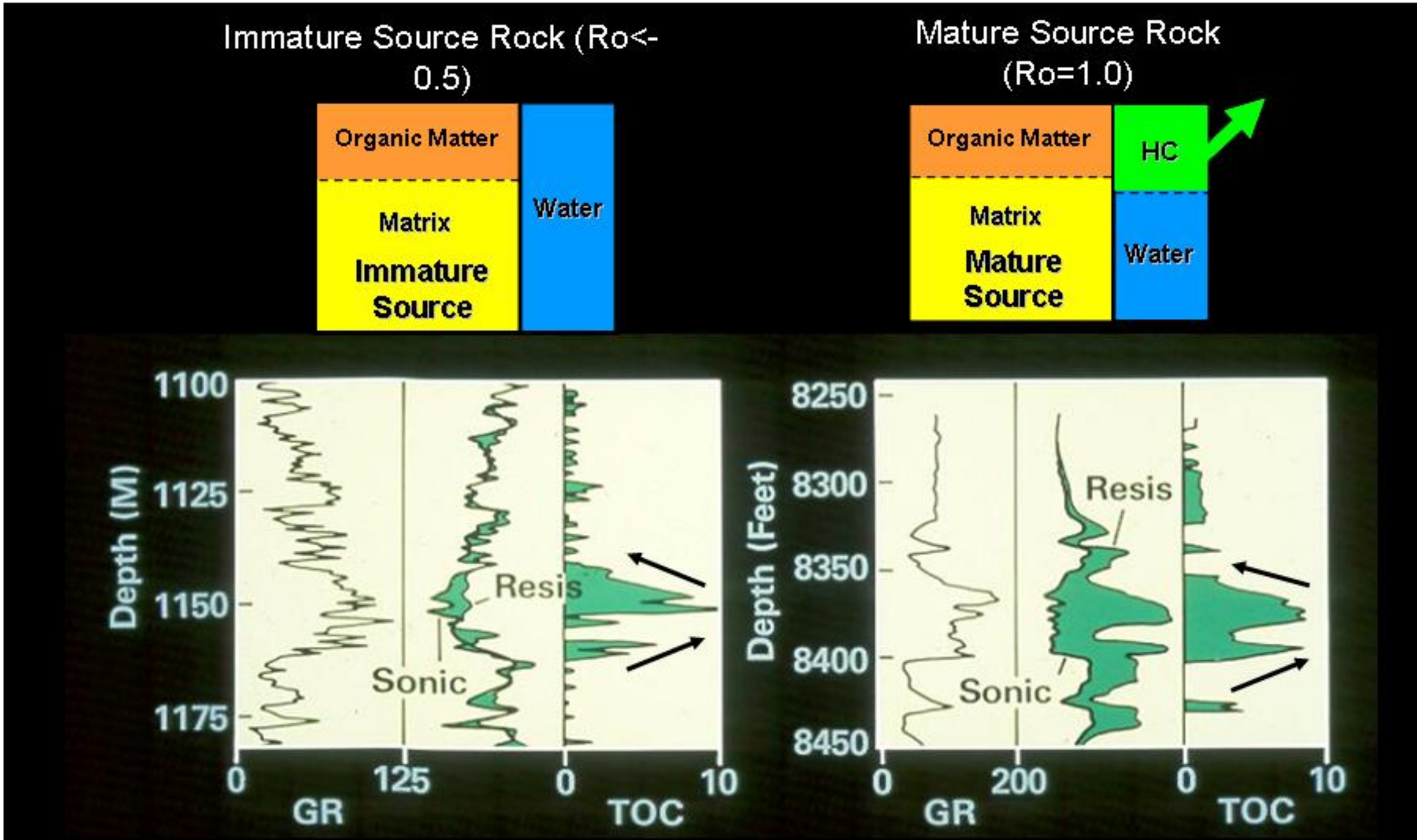


Variation in Lithology for Shale Gas Formations

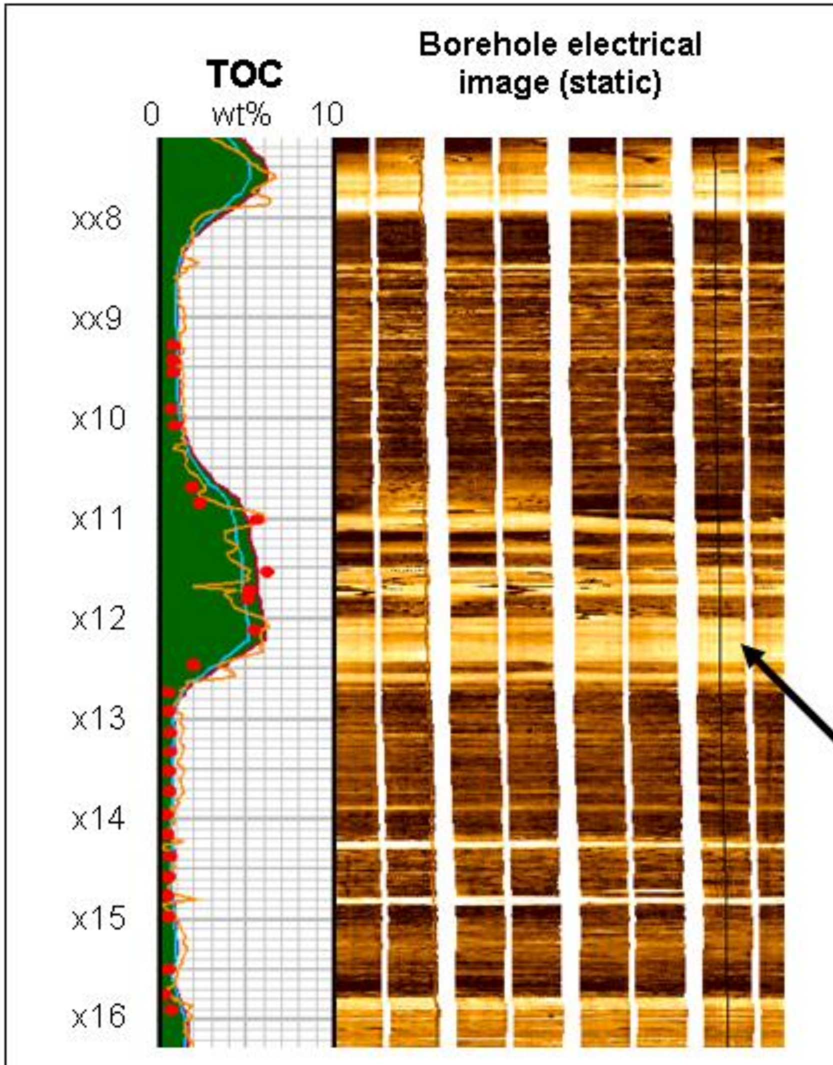


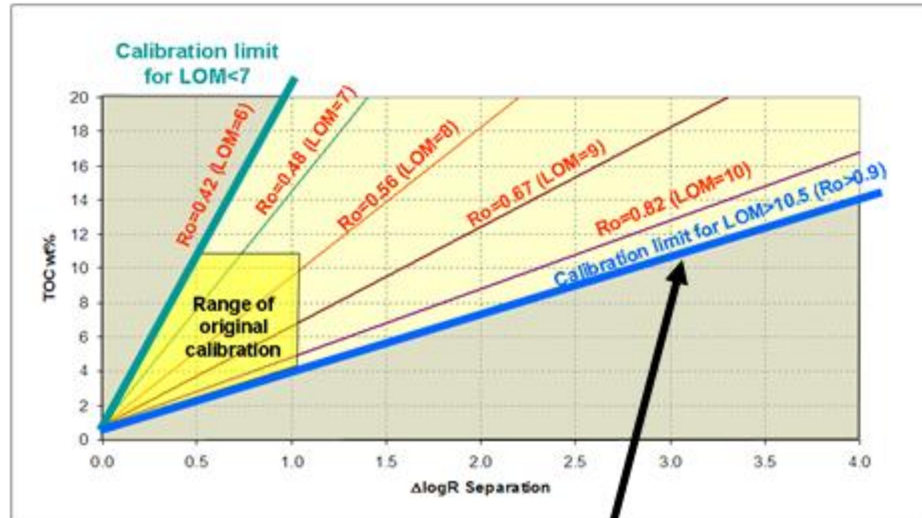


Maturity Impact on Log Response



TOC from ΔlogR and Borehole Image Log Response

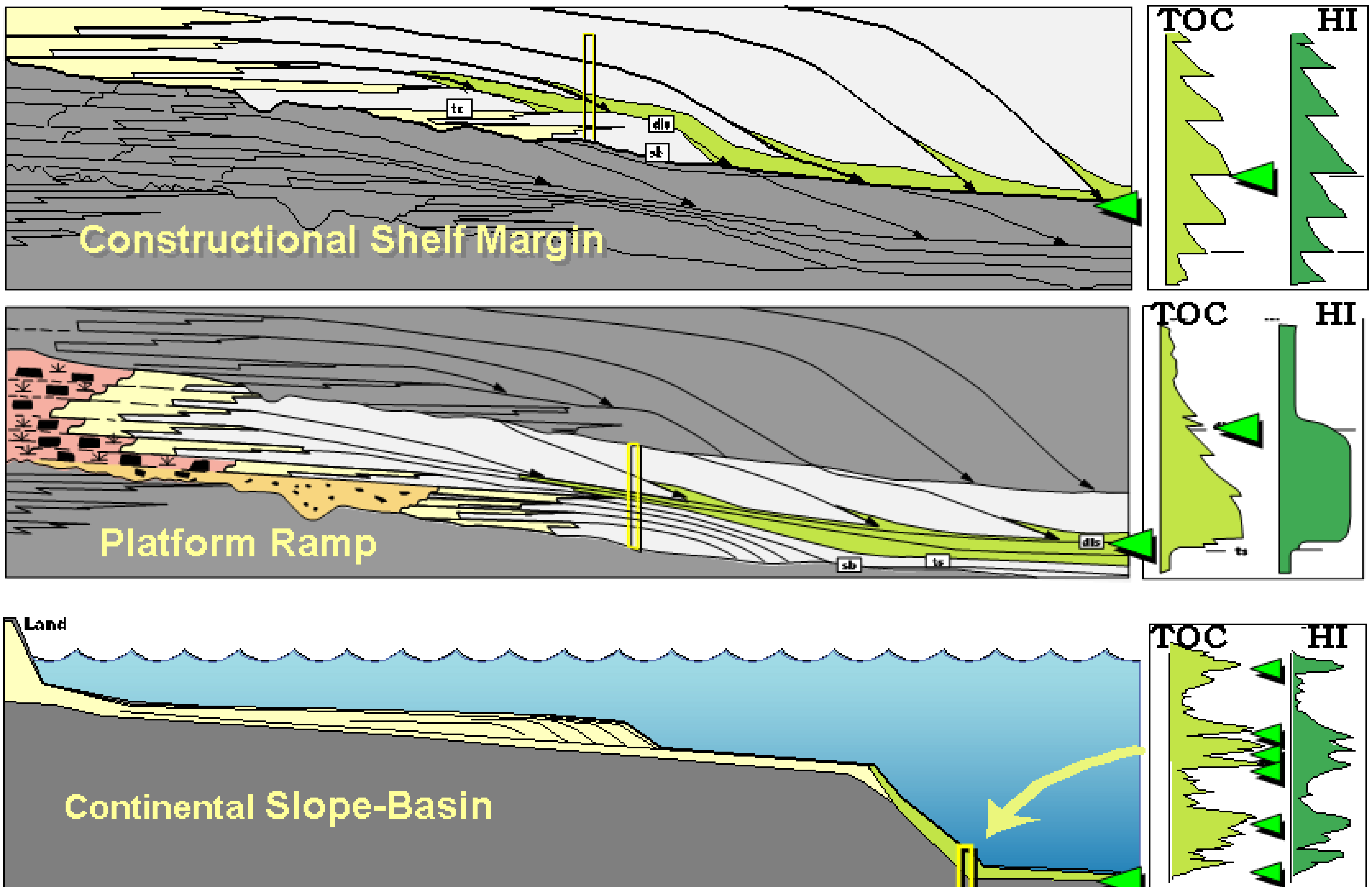




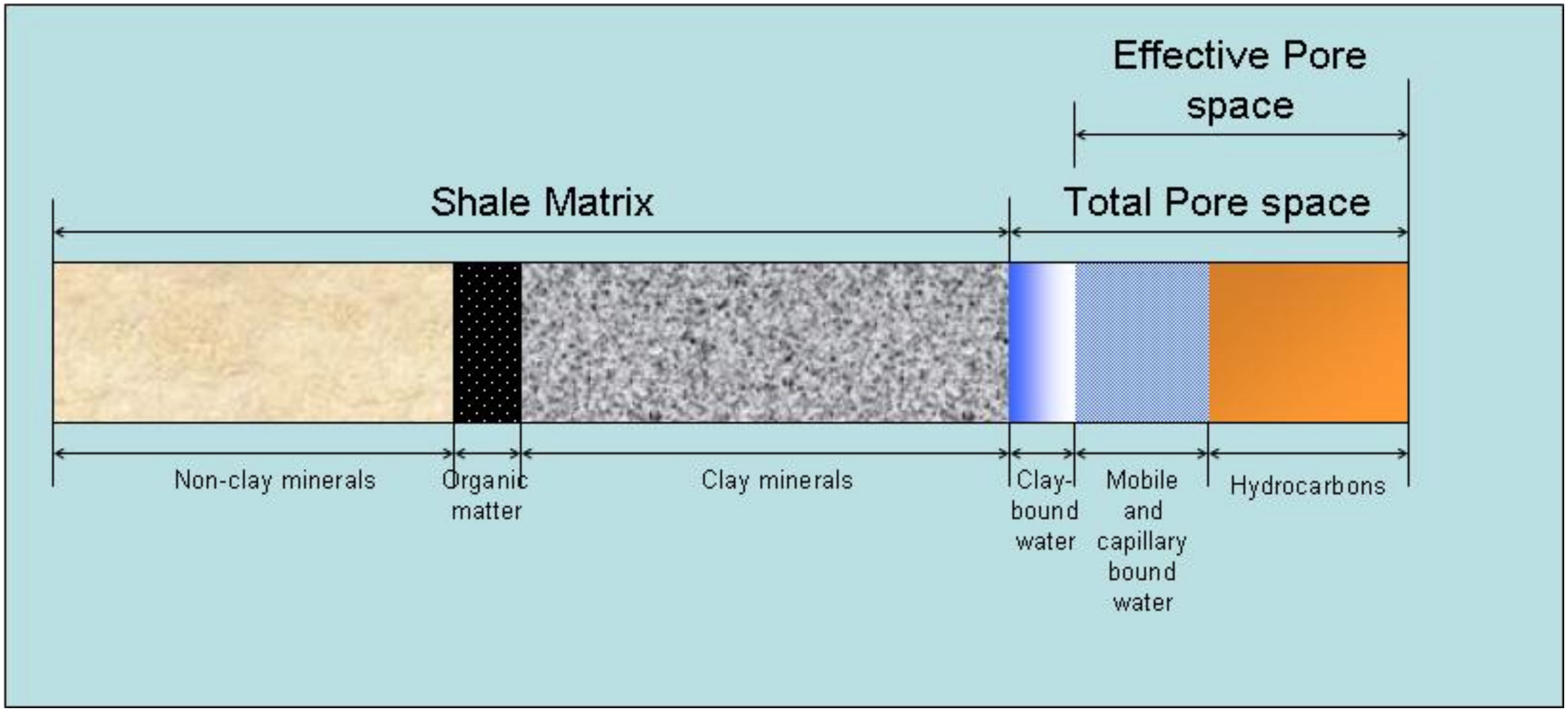
ΔlogR Calibration Limit for Overmature Shale Gas Reservoirs

Electrical Borehole Image response to “gas-filled” organic-rich intervals

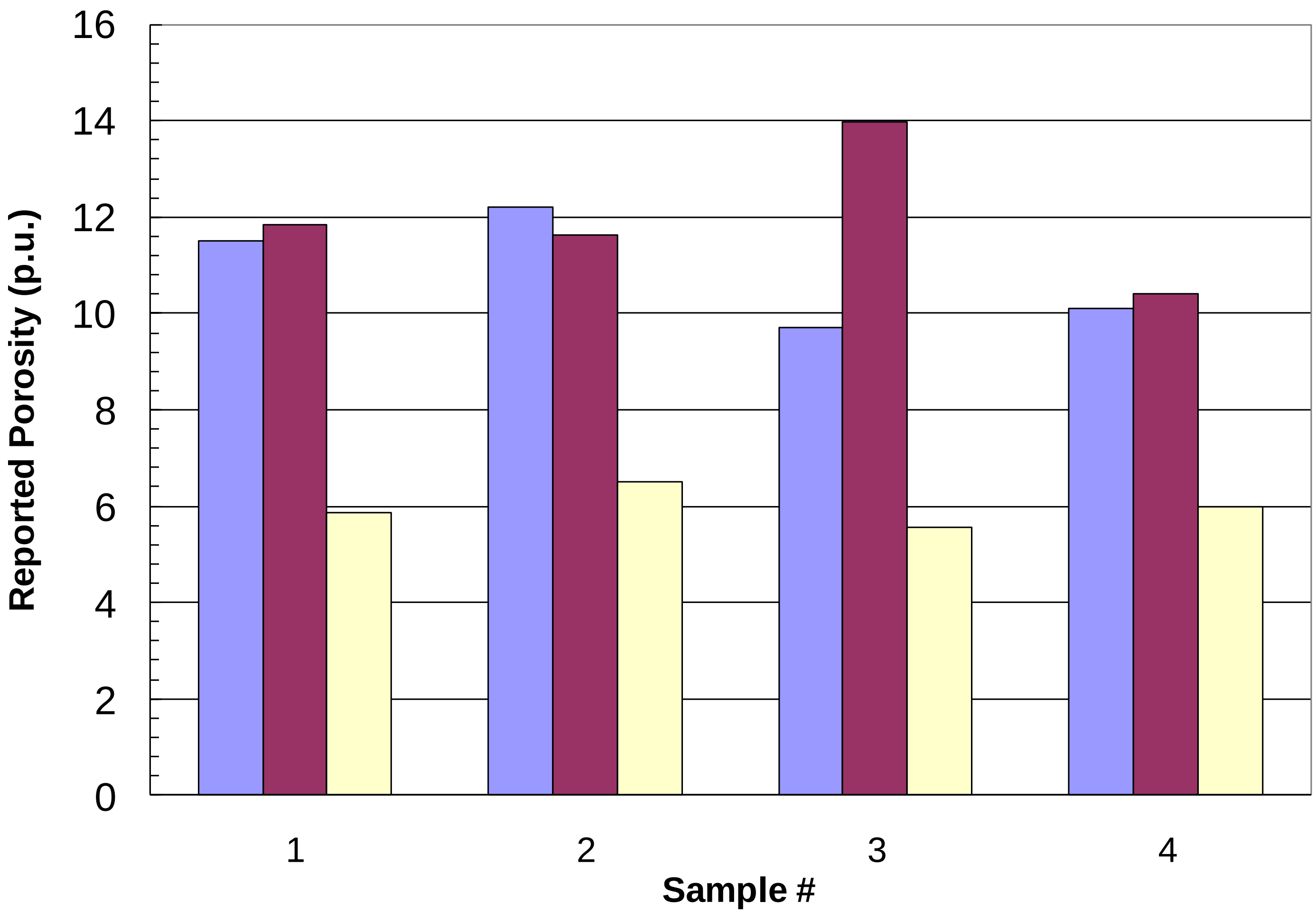
Physiographic Setting of Organic-Rich Mudstones



Definition of Total & Effective Porosity for Shale-gas Reservoirs

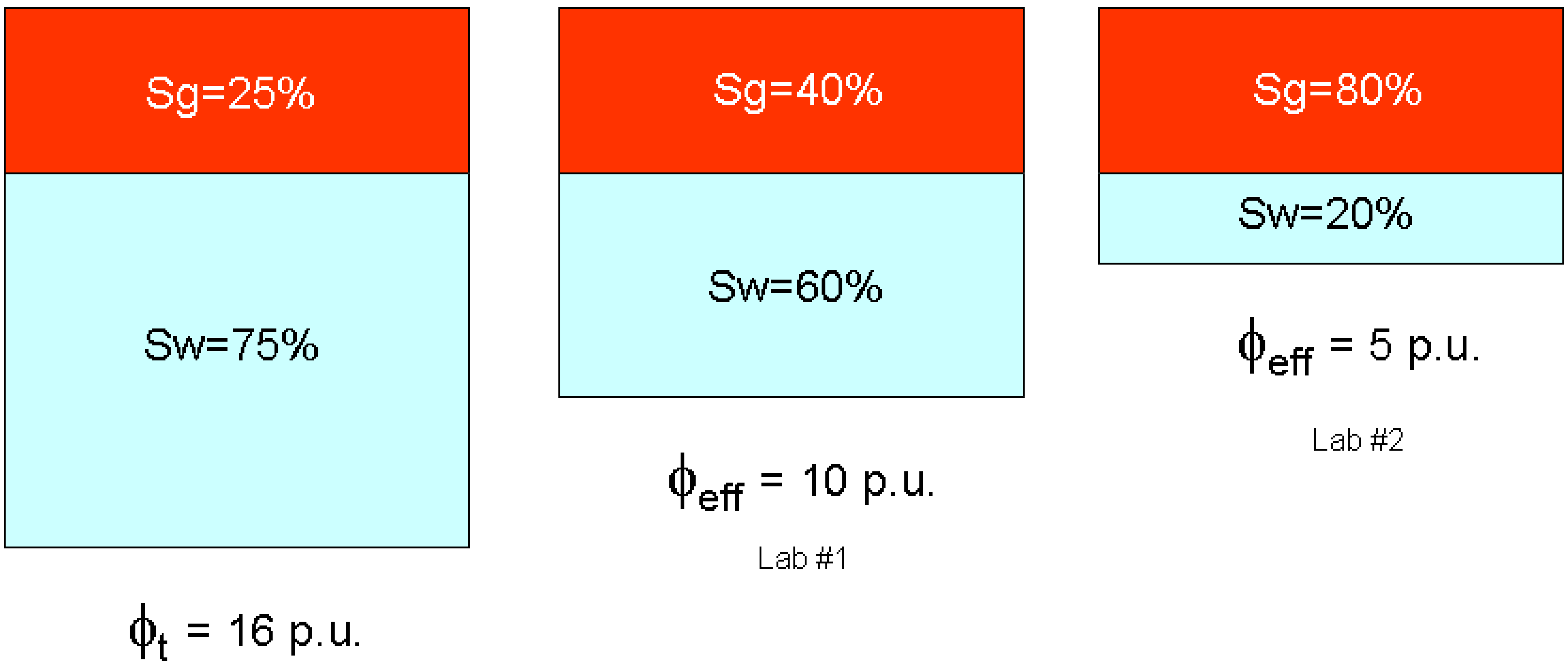


Comparison of Reported Porosity from Different Labs

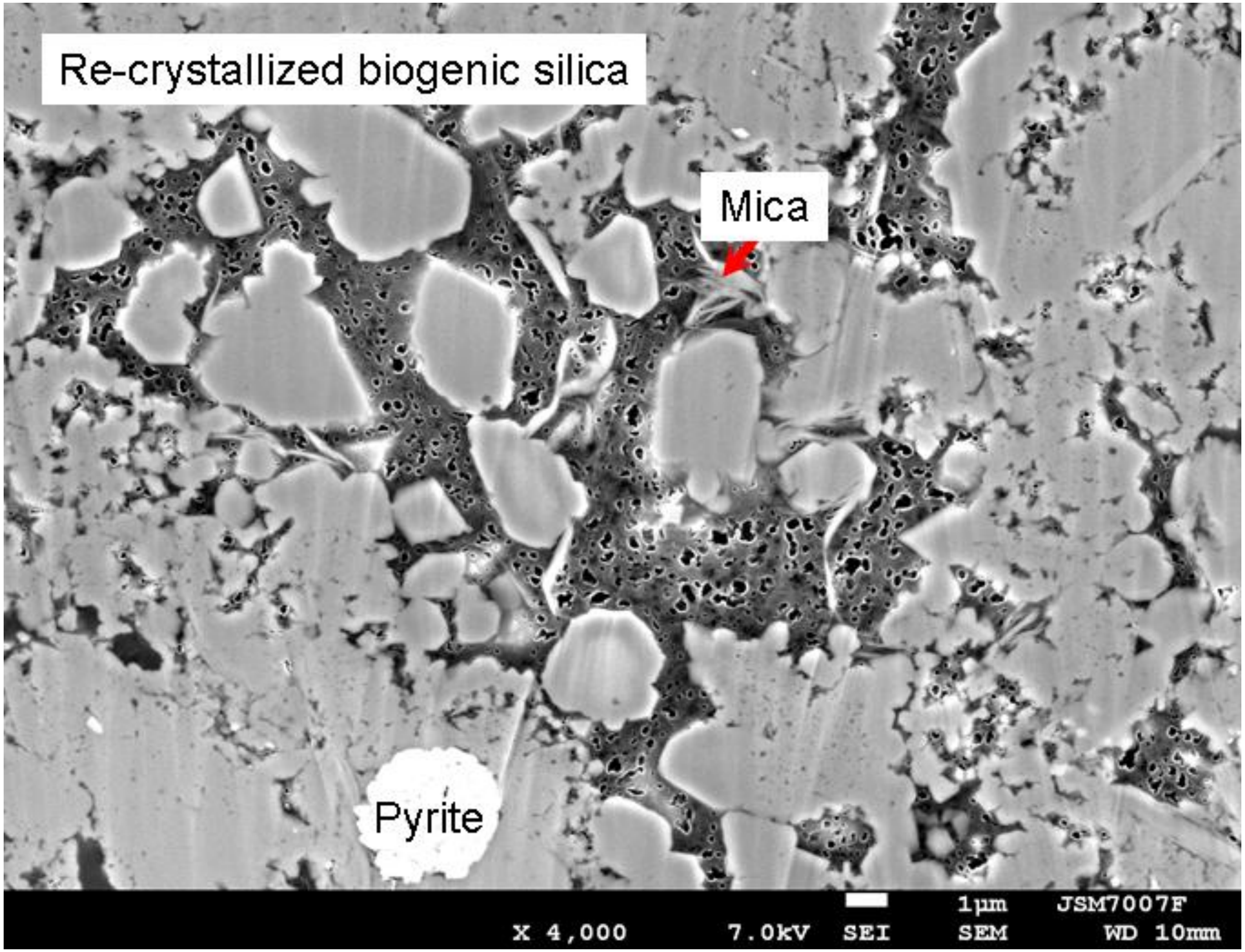


Impact of "Porosity" Definition on Calculated Gas Saturation

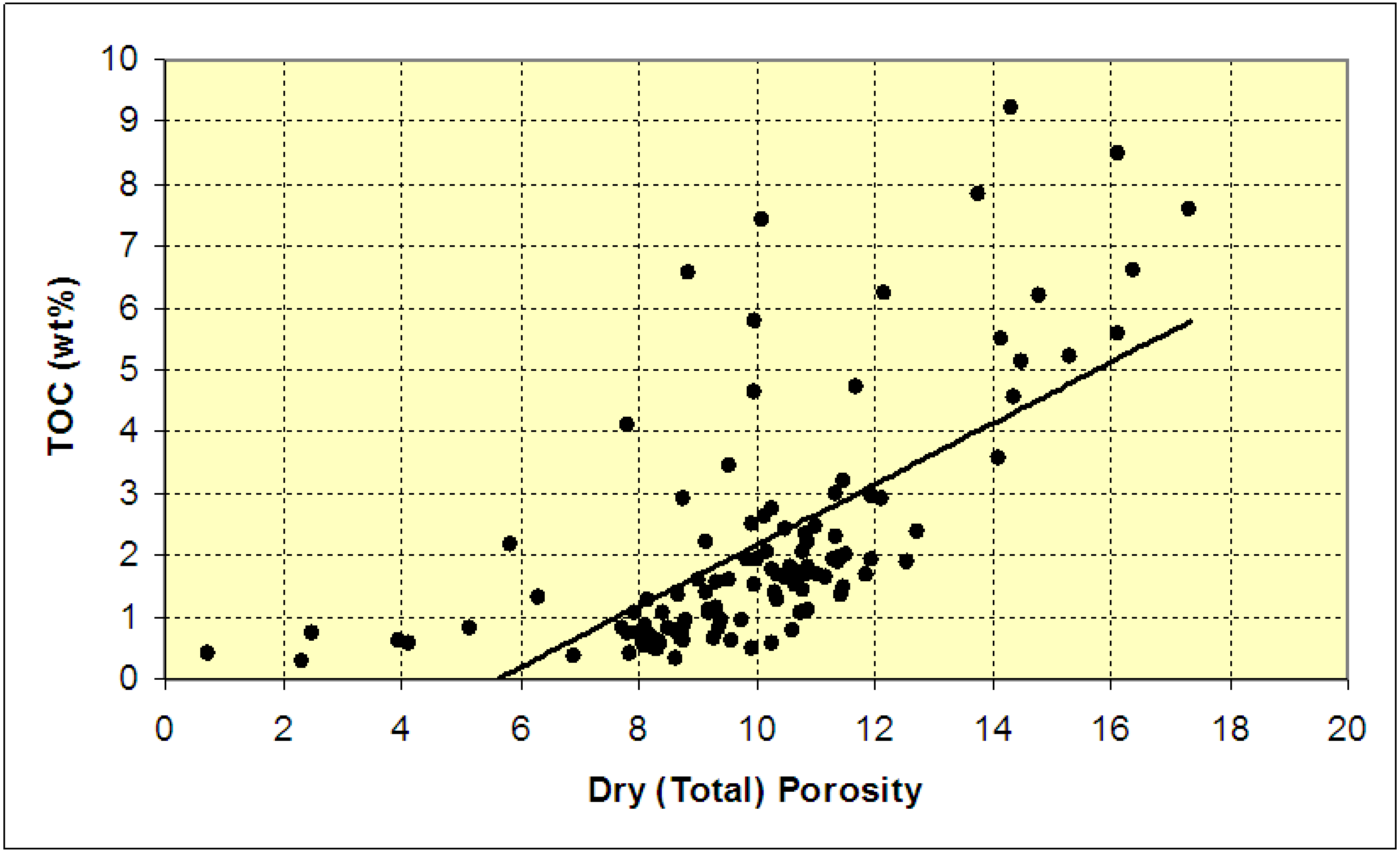
Bulk Volume Gas is constant at 4% BV



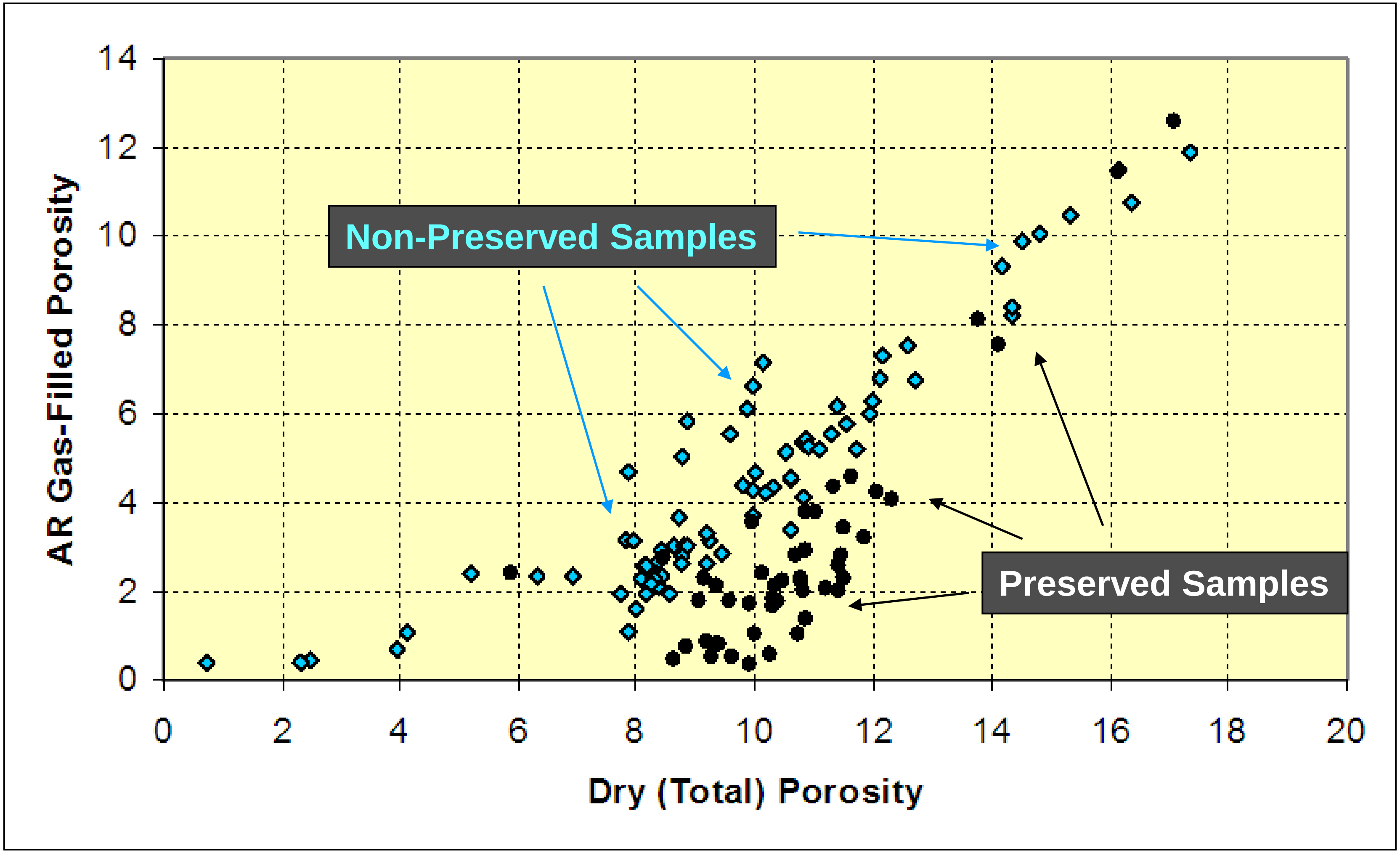
Recrystalized Biogenic Silica and Pores in Organic Matter



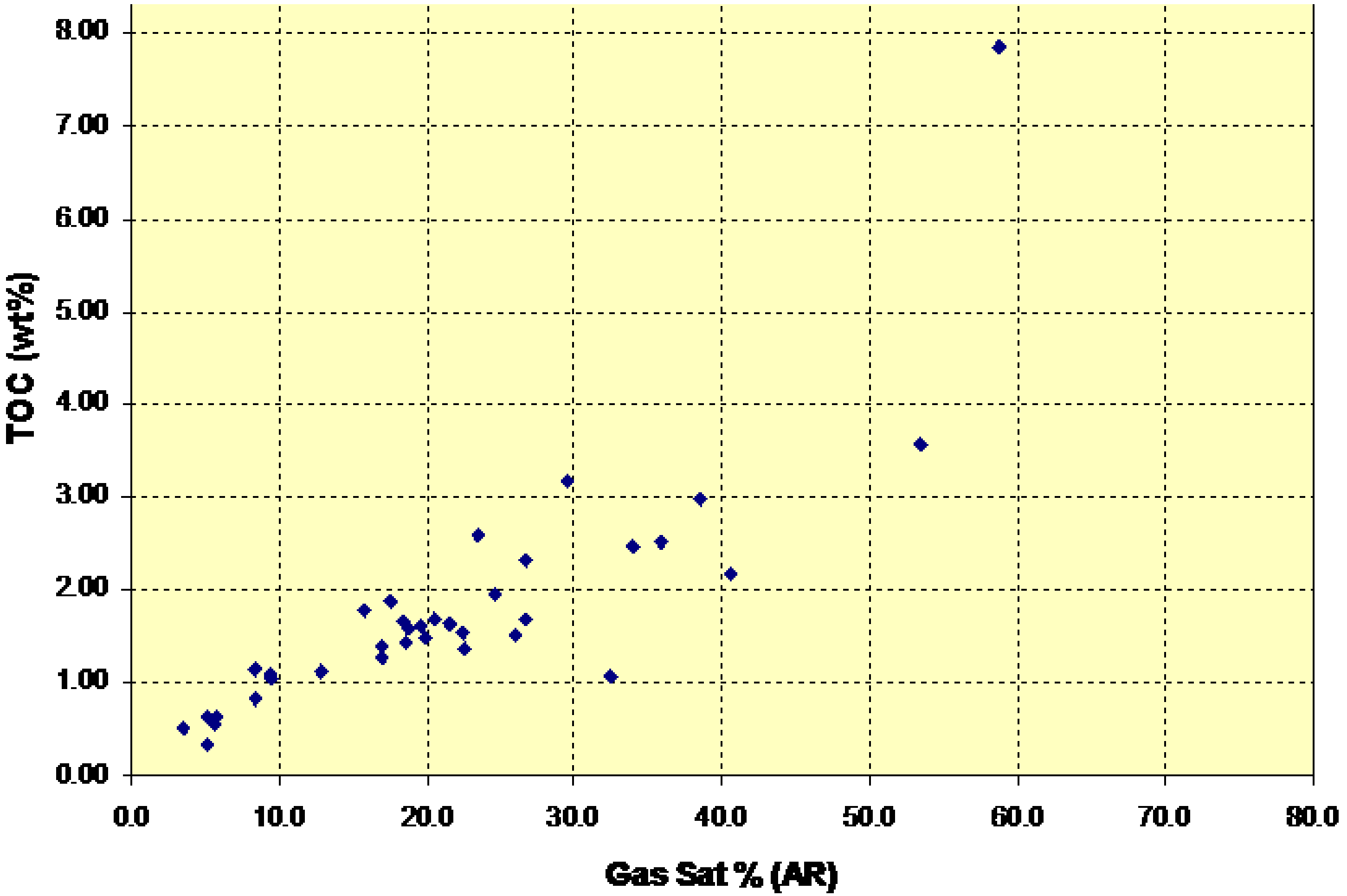
TOC versus Total Porosity in Shale Gas Reservoir



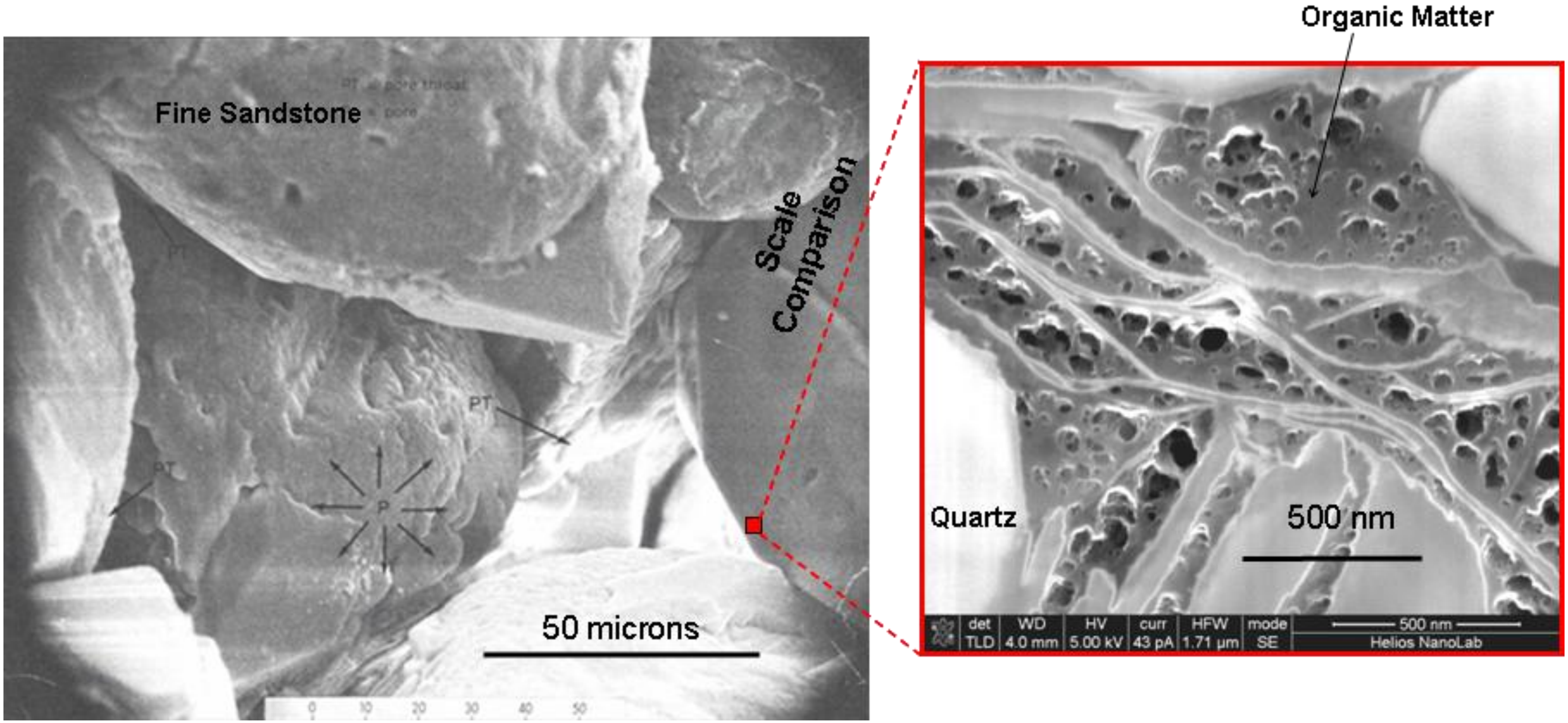
Porosity versus Gas-filled Porosity in Shale Gas Reservoir



TOC and Sg are Correlated



Pore Size Comparison – Fine Sandstone versus Organic-matter



TOC wt% ≠ TOC vol%

For a “Typical” Shale Gas the current TOC = 5 wt%

5 wt% TOC

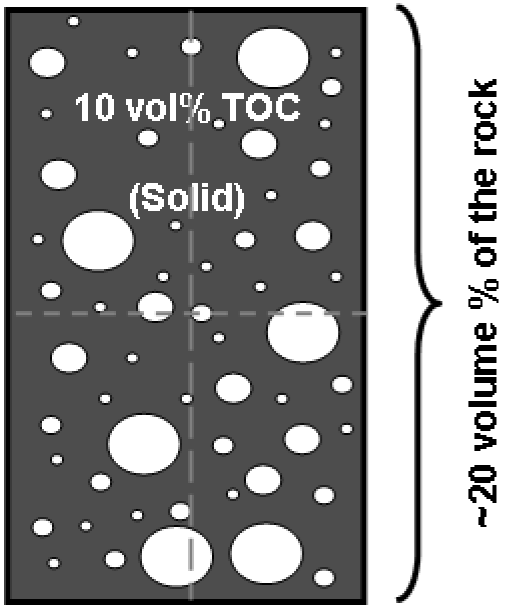
(Solid)

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

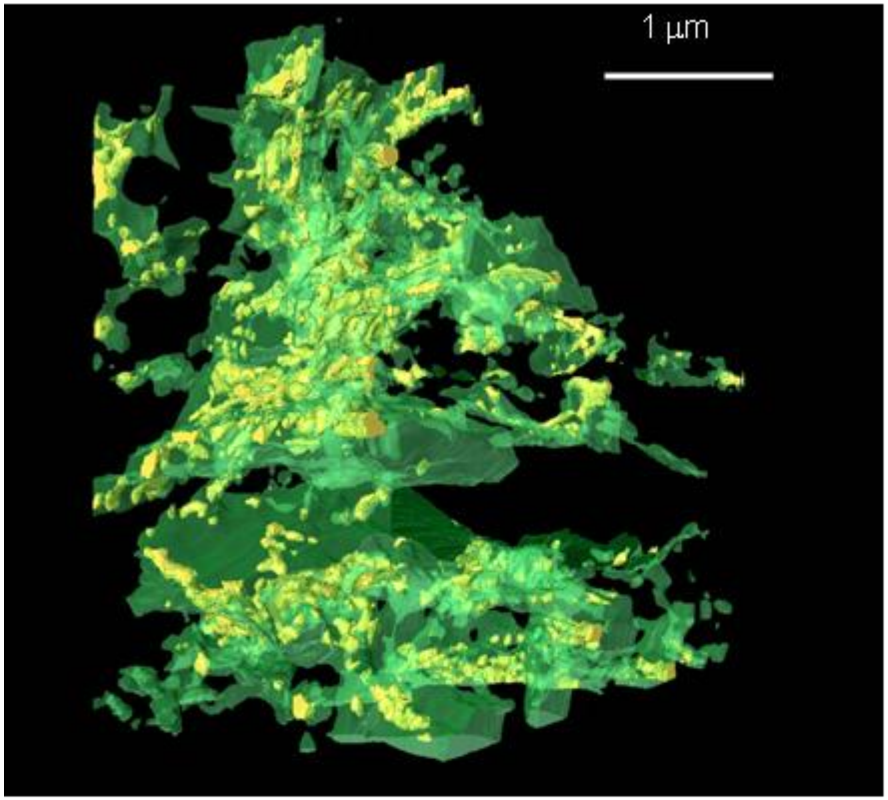
10 vol% TOC

(Solid)

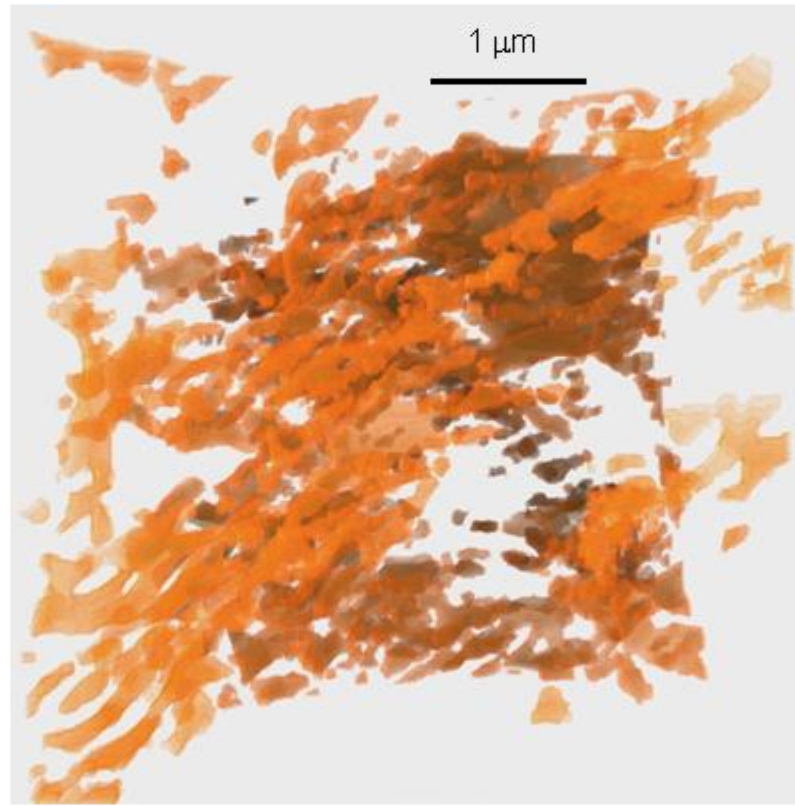
If 50 vol% of the <u>original</u> organic matter volume is now pores, the volume impacted by the current 5 wt% TOC is approximately 20 vol% of the rock.



3D Representation Pores within the Organic Matter

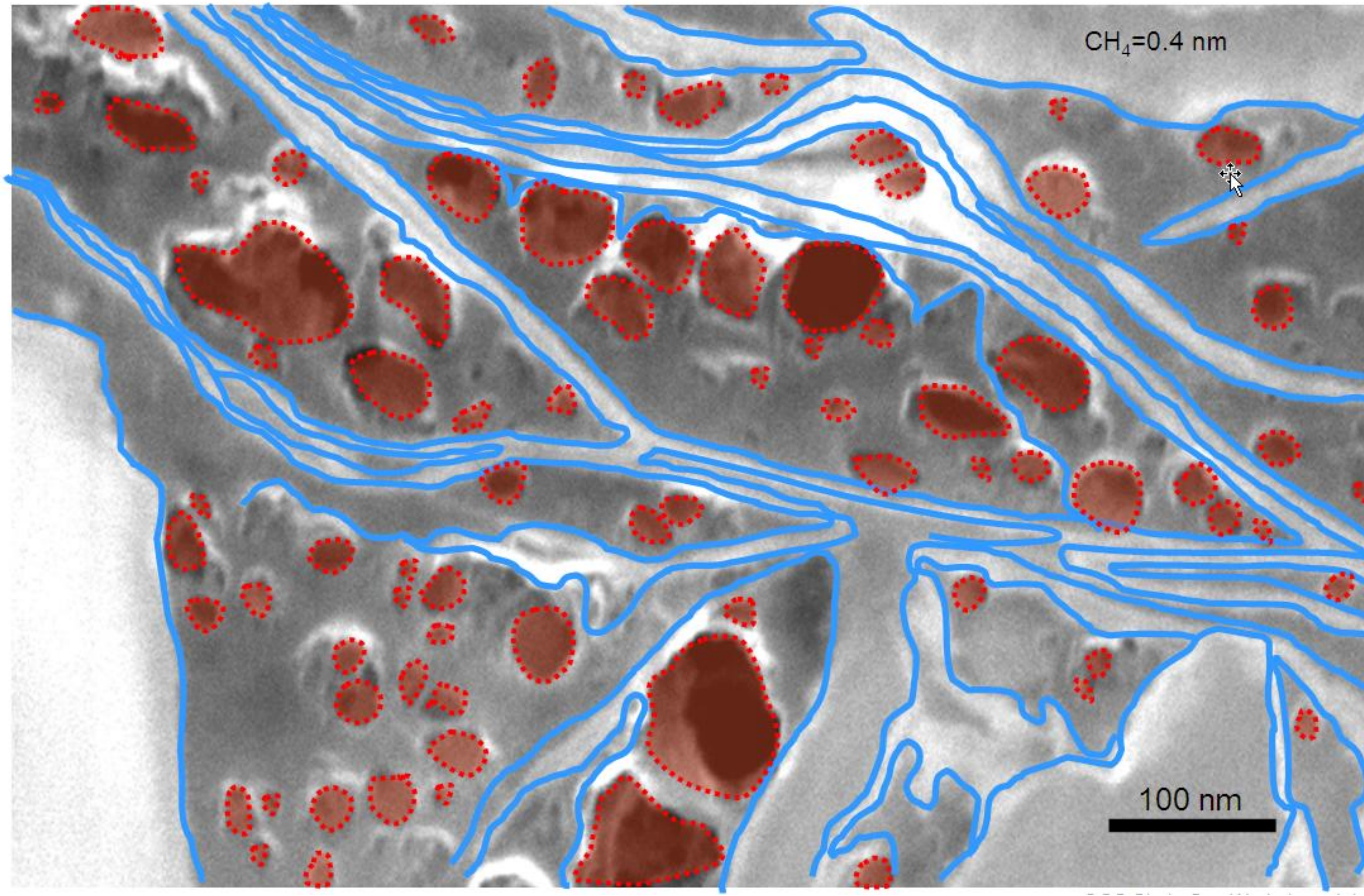


Organic Matter (Green)
Pores (Yellow)



Pores (Orange)

Hypothetical Distribution of Gas and Water



Summary

- Production, destruction, and dilution control TOC in mudstones
- Parasequence is the fundamental unit of shale gas reservoirs
- Shale-gas reservoirs are overmature oil-prone source rocks
- Porosity, TOC, and gas content are all positively correlated
- Shale-gas reservoirs comprise a large range in matrix lithologies
- Laboratory characterization of ϕ, k, and Sg is problematic
- Free gas likely to be in organic-matter porosity
- Gas-filled porosity (BVG) is better characterization term than Sg

For Further Information – SPE 131350

SPE 131350

From Oil-Prone Source Rock to Gas-Producing Shale Reservoir – Geologic and Petrophysical Characterization of Unconventional Shale-Gas Reservoirs

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This paper was prepared for presentation at the CPS/SPE International Oil & Gas Conference and Exhibition in China held in Beijing, China, 8–10 June 2010.

Abstract

Many currently producing shale-gas reservoirs are overmature oil-prone source rocks. Through burial and heating these reservoirs evolve from organic-matter-rich mud deposited in marine, lacustrine, or swamp environments. Key characterization parameters are: total organic carbon (TOC), maturity level (vitrinite reflectance), mineralogy, thickness, and organic matter type. Hydrogen-to-carbon (HI) and oxygen-to-carbon (OI) ratios are used to classify organic matter that ranges from oil-prone algal and herbaceous to gas-prone woody/coaly material.

Although organic-matter-rich intervals can be hundreds of meters thick, vertical variability in TOC is high (<1-3 meters) and is controlled by stratigraphic and biotic factors. In general, the fundamental geologic building block of shale-gas reservoirs is the parasequence, 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.

Typical analysis techniques for shale-gas reservoir rocks include: TOC, X-ray diffraction, adsorbed/canister gas, vitrinite reflectance, detailed core and thin-section descriptions, porosity, permeability, fluid saturation, and optical and electron microscopy. These sample-based results are combined with full well-log suites, including high resolution density and resistivity logs and borehole images, to fully characterize these formations. Porosity, fluid saturation, and permeability derived from core can be tied to log response; however, several studies have shown that the results obtained from different core analysis laboratories can vary significantly, reflecting differences in analytical technique, differences in definitions of fundamental rock and fluid properties, or the millimeter-scale variability common in mudstones that make it problematic to select multiple samples with identical attributes.

Porosity determination in shale-gas mudstones is complicated by very small pore sizes and, thus, large surface area (and associated surface water); moreover, smectitic clays that are commonly present in mud have interlayer water, but this clay family tends to be minimized in high maturity formations due to illitization. Finally, SEM images of ion-beam-milled samples reveal a separate nano-porosity system contained within the organic matter, possibly comprising >50% of the total porosity, and these pores may be hydrocarbon wet, at least during most of the thermal maturation process. A full understanding of the relation of porosity and gas content will result in development of optimized processes for hydrocarbon recovery in shale-gas reservoirs.

Introduction/Background

The term "unconventional reservoirs" covers a wide range of hydrocarbon-bearing formations and reservoir types that generally do not produce economic rates of hydrocarbons without stimulation. Common terms for such "unconventional" reservoirs include: Tight-Gas Sandstones, Gas Hydrates, Oil Shale formations, Heavy Oil Sandstones, and Shale Gas, among others. The focus of this paper is to discuss the geological genesis and characterization of the class of "unconventional" reservoirs commonly termed Shale Gas.

Shale is a term that has been applied to describe a wide variety of rocks that are composed of extremely fine-grained particles, typically less than 4 microns in diameter, but may contain variable amounts of silt-size particles (up to 62.5 microns). In