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

Organic Matter Type

- Type I – Algal amorphous
- Type II – Algal/Herbaceous
- Type III – Woody/coaly
- Type IV - Inertinite

Graph showing the relationship between Hydrogen Index (HI) and Oxygen Index (OI).
Maturity (LOM/Ro) – Type II Kerogen and Coal Rank

**Typical Type II Kerogen**

- Solid OM (depositional)
- Bitumen
- Oil
- Pyrobitumen
- Gas

**Coal Rank**

<table>
<thead>
<tr>
<th>Peat</th>
<th>Lignite</th>
<th>Sub-Bituminous</th>
<th>Bituminous</th>
<th>Semi-Anthracite</th>
<th>Anthracite</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>High A</td>
<td>Medium B</td>
<td>Low C</td>
<td></td>
</tr>
</tbody>
</table>
Controls On Organic-Richness

- Upwelling
  - Water-Mass Mixing
  - River Influx
  - Evaporative Cross Flow
- Sunlight
  - Nutrient Supply
  - Water Supply
- Production
- Consumer Population
- Oxidant Supply Rate
- Burial Rate
- Clastic Supply Rate
- Biogenic Supply Rate
- Chemical Supply Rate
- Destruction
- Dilution
- Accommodation
- ORR
1-2 m thick Parasequences in Mudstones

Luman Tongue, Hiawatha Section, Green River Basin, WY
Parasequence Lithofacies Stacking Pattern

Top Flooding Surface

Basal Flooding Surface

2 meters

10.0 mm
Woodford Shale – 20 wt% TOC \(\rightarrow\) 40 vol% Kerogen

*Apply threshold Fluorescing kerogen (Tasmanites cysts of marine algae)*
TOC Variability in Exshaw Formation

Exshaw Siltstone Member

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

Upper calcareous black shale

Lower non-calcereous black shale

5 feet

Palliser (Costigan Member)

Sandy Dolostone

OGS New Perspectives on Shales – July 28, 2010
Vertical Variability
Scale of cm to meters

TOC (wt%)

Gamma Ray

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Variation in Lithology for Shale Gas Formations

Clay-rich gas-bearing mudrock

Barnett

Eagleford

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Maturity Impact on Log Response

Immature Source Rock (Ro< 0.5)
- Organic Matter
- Matrix
- Immature Source
- Water

Mature Source Rock (Ro=1.0)
- Organic Matter
- Matrix
- Mature Source
- Water
- HC
- Resis

Graphs showing depth, GR, Sonic, TOC for immature and mature source rock. Arrows indicate changes in log responses.
TOC from $\Delta \log R$ and Borehole Image Log Response

$\Delta \log R$ Calibration Limit for Overmature Shale Gas Reservoirs

Electrical Borehole Image response to “gas-filled” organic-rich intervals
Physiographic Setting of Organic-Rich Mudstones

- Constructional Shelf Margin
- Platform Ramp
- Continental Slope-Basin
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

<table>
<thead>
<tr>
<th>Sg</th>
<th>Sw</th>
<th>$\phi_t$</th>
</tr>
</thead>
<tbody>
<tr>
<td>25%</td>
<td>75%</td>
<td>16 p.u.</td>
</tr>
<tr>
<td>40%</td>
<td>60%</td>
<td>10 p.u.</td>
</tr>
<tr>
<td>80%</td>
<td>20%</td>
<td>5 p.u.</td>
</tr>
</tbody>
</table>

$\phi_{eff} = 5$ p.u.  
Lab #2

$\phi_{eff} = 10$ p.u.  
Lab #1
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

Non-Preserved Samples

Preserved Samples
TOC and Sg are Correlated
Pore Size Comparison – Fine Sandstone versus Organic-matter

Fine Sandstone

Organic Matter

Quartz

500 nm

Scale Comparison

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

- **5 wt% TOC (Solid)**
  - Because the grain density of organic matter is \(\sim \frac{1}{2}\) that of rock minerals, the vol% TOC is \(\sim 2\) times the wt% TOC.

- **10 vol% TOC (Solid)**
  - If 50 vol% of the original organic matter volume is now pores, the volume impacted by the current 5 wt% TOC is approximately 20 vol% of the rock.

\(~\sim 20\) volume % 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 $\phi$, $k$, and $S_g$ is problematic
• Free gas likely to be in organic-matter porosity
• Gas-filled porosity (BVG) is better characterization term than $S_g$
From Oil-Prone Source Rock to Gas-Producing Shale Reservoir – Geologic and Petrophysical Characterization of Unconventional Shale-Gas Reservoirs

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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 (H:C) and oxygen-to-carbon (O:C) ratios are used to classify organic matter that ranges from oil-prone algal and bacteriaceous 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 in the parasequence, and commonly 10% to 100% of parasequences comprise the organic-rich formation whose lateral continuity can be estimated using techniques and models developed for source rock.

Typical analysis techniques for shale-gas reservoir rocks include: TOC, X-ray diffraction, adsorbed-carbon 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, unconsolidated clays that are commonly present in mud have interlayer water, but this clay finally tends to be minimized in high maturity formations due to diagenesis. Finally, SEM images of core-derived 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 be vital 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