

Picture by Allen Kimble,  
Cano Petroleum

# *Compaction Model for Hydrocarbon Generation in Shale*

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SPECIAL CORE ANALYSIS LABORATORIES, INC.

# *The Hydrocarbon Generation*

Some Factors Controlling the Hydrocarbon Generation and Entrapment

Pressure

Volume

Temperature

Kerogen Type

Geological Time

Compaction

Expulsion

Molecular Sieving

Migration

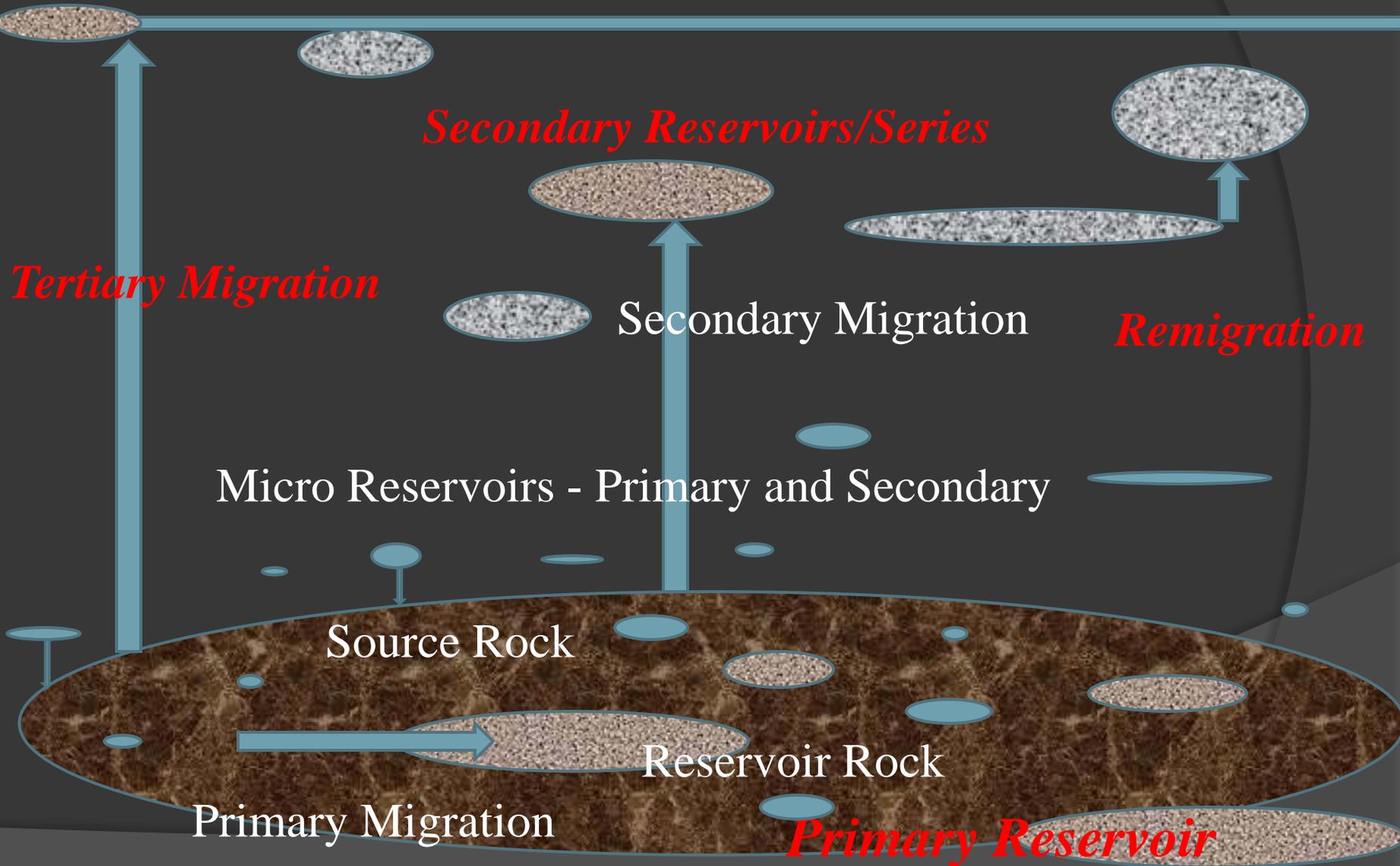
Rock Properties

Fluid Properties

Rock-Fluid Interaction

The more factors we use to describe the process the better the results.

# *Oil and Gas Migration - The Primary Reservoir*



# *The Primary Reservoir Terminology*

## *Required Phases for a Hydrocarbon Accumulation*

Source Rock

is SHALE

Trapping

done by the compacting SHALE

Seal Rock

is the highly compacted SHALE

**Primary Reservoir Rock**

has coarser grains (less compacted) and is called SHALE MIX. This rock is capable of storing liquid hydrocarbons.

Free oil (geochemistry S1) is the residual oil (has cut fluorescence) left in a source rock after it has generated oil and gas. PPB Oil (parts per billion).

Free oil (oil and gas terminology) means producible (movable continuous oil phase). BBL Oil.

# *Molecular Sieving*

Exploring for Oil and Gas Traps, Edward A. Beaumont and Norman H. Foster, AAPG 1999, Page 7-9

Molecule	Diameter nm
Water	.30
Methane	.38
Normal Paraffins	.4-10
Aromatic	.8-20
Benzene	.47
Cyclohexane	.54
Complex Rings	1-3
Asphaltenes	5-40
Helium	.098
Mercury	.314

*“Pore throats act as molecular sieves, allowing particles smaller than the orifice to pass and retaining larger particles.”*

# *Why do we have gas in the shale oil source?*

While the thermal maturity starts and maintains the hydrocarbon generation the source rock compaction controls the output of the generation. The quantity and quality is controlled by molecular sieving and the hydrocarbon generation speed. Compaction can slow down the hydrocarbon generation. The generation potential (S2) seems to also indicate that the generation process was not totally exhausted.

A combination of thermal maturity and compaction can explain why the source rock in “shale oil plays” (while still in the oil window) is gas bearing and no continuous oil phase is present.

The gas content in “shale oil plays” is very large and in many instances is higher than the gas measured in mature “shale gas plays”.

# *The Compaction Model*

Let's assume we have a type 2 kerogen (oil and gas prone). Type 1 (oil prone) and type 3 (gas prone) kerogens will also match this model.

The continuous burial will increase the compaction pressure (net overburden pressure; litho static minus hydrostatic) and will also increase the temperature (maturity).

The pore pressure is controlled by the normal hydrostatic pressure and by the high local pressures associated with the hydrocarbon generation (large volumes of oil and gas formed in a confined space). If the generation process is fast, local temperature increases around the generation points are possible. Natural radioactivity can also increase the temperature. *Today's temperature gradient can be very different than the generation gradient.*

At one point the local pressures are enough to generate horizontal fractures. Temperatures are relatively low under 200 °C (porphyrines ).

# *Phase 1. Open Hydrocarbon Generation – Fast Generation*

The burial temperature is high enough to start the hydrocarbon generation.

The volume of the generated hydrocarbons increases the pressure and temperature around the kerogen rich areas. When these pressures are high enough to overcome the capillary plus hydrostatic pressures a slug of hydrocarbons is expelled following the path of least resistance.

The hydrocarbon transport is controlled by slug flow in this phase.

The produced hydrocarbons are expelled into the primary reservoir rock first and after filling the primary reservoir rock the hydrocarbons migrate upward (or the path of least resistance) to form secondary normal pressured oil reservoirs.

The API gravity increases with the burial (molecular sieving due to compaction).

The seal quality can and will influence the final reservoir composition. Shale seals can and will diffuse gas.

## *Phase 2. Trapped Hydrocarbon Generation – Medium Generation*

The pore size of the shale source becomes smaller. The larger liquid hydrocarbon molecules become trapped in the smaller pores and are cracked to lighter phases.

The generated hydrocarbons partially escape to form secondary condensate reservoirs and will “inflate” the primary reservoir rock with lighter gassier components mixing with the hydrocarbons produced in the first phase. The short mostly horizontal hydrocarbon generation fractures are formed in this phase.

New secondary reservoirs will be condensate.

The API continues to increase with the burial (molecular sieving due to compaction).

The primary reservoir becomes over pressured as the hydrocarbon generation pressures can not totally escape.

The seal quality can and will influence the final reservoir composition.

## *Phase 3. Sealed Hydrocarbon Generation – Slow Generation*

The pore size of the source becomes very small as the burial increases. The weight of the overburden becomes very high. Most of the liquid hydrocarbons become trapped in the smaller pores and cracked to gas. The generated gas is mixed with the phase 1 and 2 generated hydrocarbons. The mixture becomes lighter and lighter as the thermal maturity increases. The hydrocarbon generation becomes very slow. The generation pressures can not fracture the shale as it did in phase 2 due to higher litho static pressure.

Gas generation and transport is controlled now by molecular diffusion (migration). Only gas can be generated in this phase.

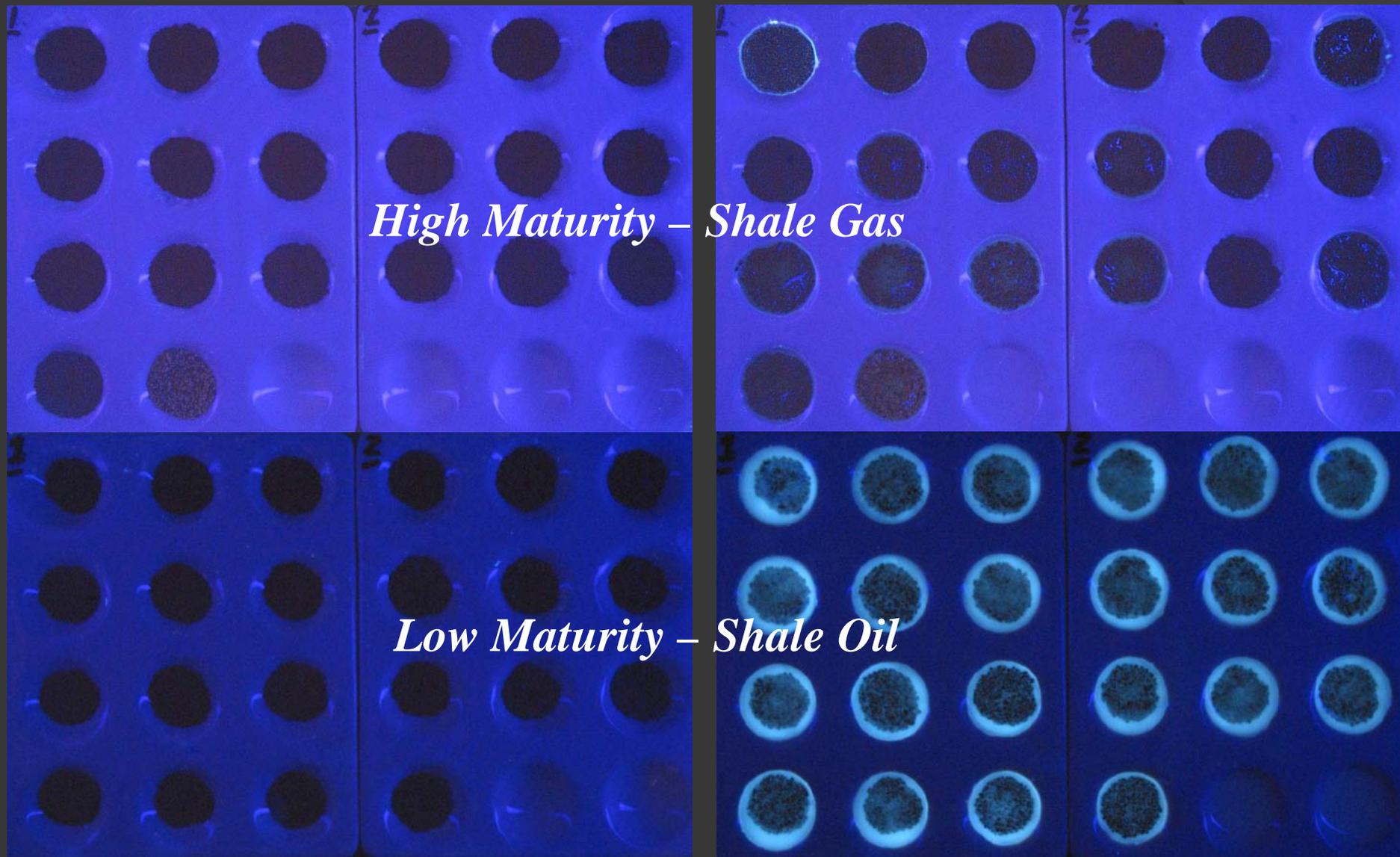
New secondary reservoirs generated will be gas.

In the oil window liquid hydrocarbons are present only in the primary reservoir rock .

**The source rock is gas saturated and does not have matrix fluorescence/oil.**

In the gas window all the liquid hydrocarbons are cracked and gas is present both in the source and primary reservoir rock . The gas density continues to decrease (wet gas to dry gas) with the burial.

# Source Rock Fluorescence



*High Maturity - Shale Gas*

*Low Maturity - Shale Oil*

Before the addition of a cutting solvent

After the addition of a cutting solvent, with empty wells for comparison

# *Kerogen and “In-Kerogen Shows”*

“The kerogen is insoluble in the usual organic solvents.”

However, hot solvents extraction over long time periods on crushed samples will extract at least part of the kerogen generating significant porosity in the source rock leading to over evaluation. The high extraction temperatures (often higher than reservoir temperature) applied to the unstressed crushed samples can generate hydrocarbons, solubility and extraction.

“In-kerogen shows occur when solvents are used on cuttings containing kerogen. The solvent liberate some oil from the kerogen, *and this oil can be mistaken for evidence of free oil.* In-kerogen shows indicate the presence of source rocks that have generated oil and gas.”

# *Shale Gas*

- ◎ Primary reservoir
- ◎ Maturity: gas window
- ◎ Generation: open, trapped and later sealed
- ◎ Source rock: dry gas bearing shale (desorption and diffusion)
- ◎ Reservoir rock: tight, gas bearing (conventional)
- ◎ Matrix Fluorescence:
  - source rock **none**
  - reservoir rock **possible slight cut**

# *Shale Oil*

- ◎ Primary reservoir
- ◎ Maturity: oil window
- ◎ Generation: open and later trapped
- ◎ Source rock: wet or dry gas bearing shale (desorption and diffusion)
- ◎ Reservoir rock: tight, **oil and gas bearing (conventional)**
- ◎ Matrix Fluorescence:
  - source rock **none, good cut**
  - reservoir rock **good**

The natural matrix fluorescence can be used to find the transition from source to reservoir.



*To have oil production the shale source/seal needs:*

**1. Storage capacity. Oil saturated porosity.**

No oil saturation/matrix fluorescence. The large porosities and small oil saturations measured by the so called “GRI method” are laboratory generated due to kerogen conversion, extraction and/or evaporation. FAIL

**2. Transport capacity. Effective/relative oil permeability (oil flow in the presence of water and gas saturations). The matrix permeability is very low. FAIL**

# *The Shale Matrix Oil Production*

## *“The GRI Standard ?” and “The GRI Nano Oil Well”*

### *Direct Versus Indirect Core Analysis*

Darcy's linear flow equation. (assuming that we do have oil and this oil can flow through the shale matrix):

Typical results using “the GRI shale oil analysis standard”;

The procedure calls for sample extraction in hot toluene for one week

Permeability =  $7E-10$  mD

Porosity = 11%

Oil extracted  $S_o = 25\%$

Bulk density = 2.5 g/cc (start with a wet shale)

Grain density = 2.71 g/cc (end with a dry limestone)

Assume: Multistage fracturing job with 1,000,000 sqft total  
Pressure gradient: 5,000 psi/ft; Oil viscosity: .5 cP

***This well will produce .009 bbl of oil/day***

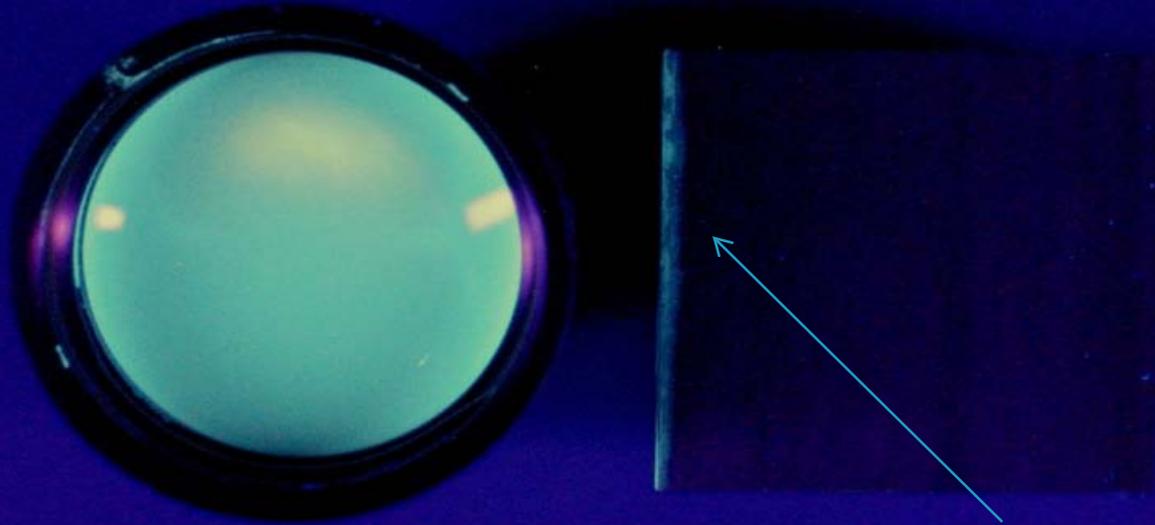
***With “Kr modeling” more like “nano bbl/day “ (.0015 cc/day)***

## Reservoir Conditions Effective Oil Permeability

Confining Pressure	5,600	psi	DST Oil	40.4	API
Pore Pressure	2,500	psi	Viscosity	1.729	cP
Diferential Pressure	2,500	psi	Diameter	2.54	cm
Temperature	151	°F			

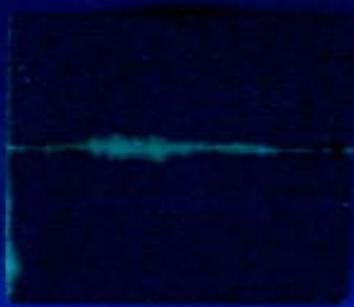
Sample	Depth ft	Q cc/min	L cm	Keo mD	Klinkenberg mD	Observations
7	5,591.8	0.00000	1.983	0.000000	0.0011	
12	5,596.7	0.00000	2.165	0.000000	0.0031	
19	5,603.4	0.00000	2.628	0.000000	0.0007	
24	5,608.8	0.00000	2.449	0.000000	0.0010	
<b>29</b>	<b>5,613.9</b>	<b>0.00250</b>	<b>2.211</b>	<b>0.000185</b>	<b>0.0031</b>	<b>Fracture</b>
<b>31</b>	<b>5,615.4</b>	<b>0.00104</b>	<b>2.134</b>	<b>0.000074</b>	<b>0.0034</b>	<b>Fracture</b>
32	5,616.9	0.00000	2.154	<b>0.000000</b>	0.0022	
35	5,619.7	0.00000	2.159	<b>0.000000</b>	0.0018	
39	5,623.4	0.00000	2.207	<b>0.000000</b>	0.0028	

# Effective Oil Permeability Test UV Pictures

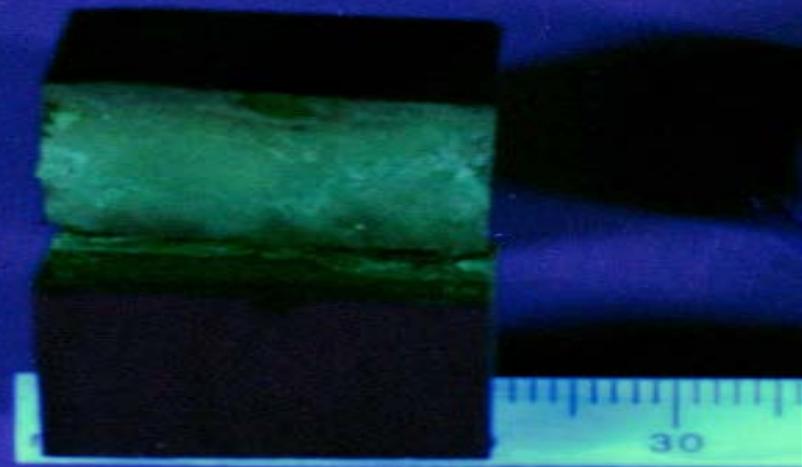


Zero Matrix Permeability

## Fracture Permeability



## Open Fracture Fluorescence



# *Crushed Rock Analysis Problems*

Crushing the shale:

Decreases the porosity.

Decreases the matrix permeability.

Increases the surface area.

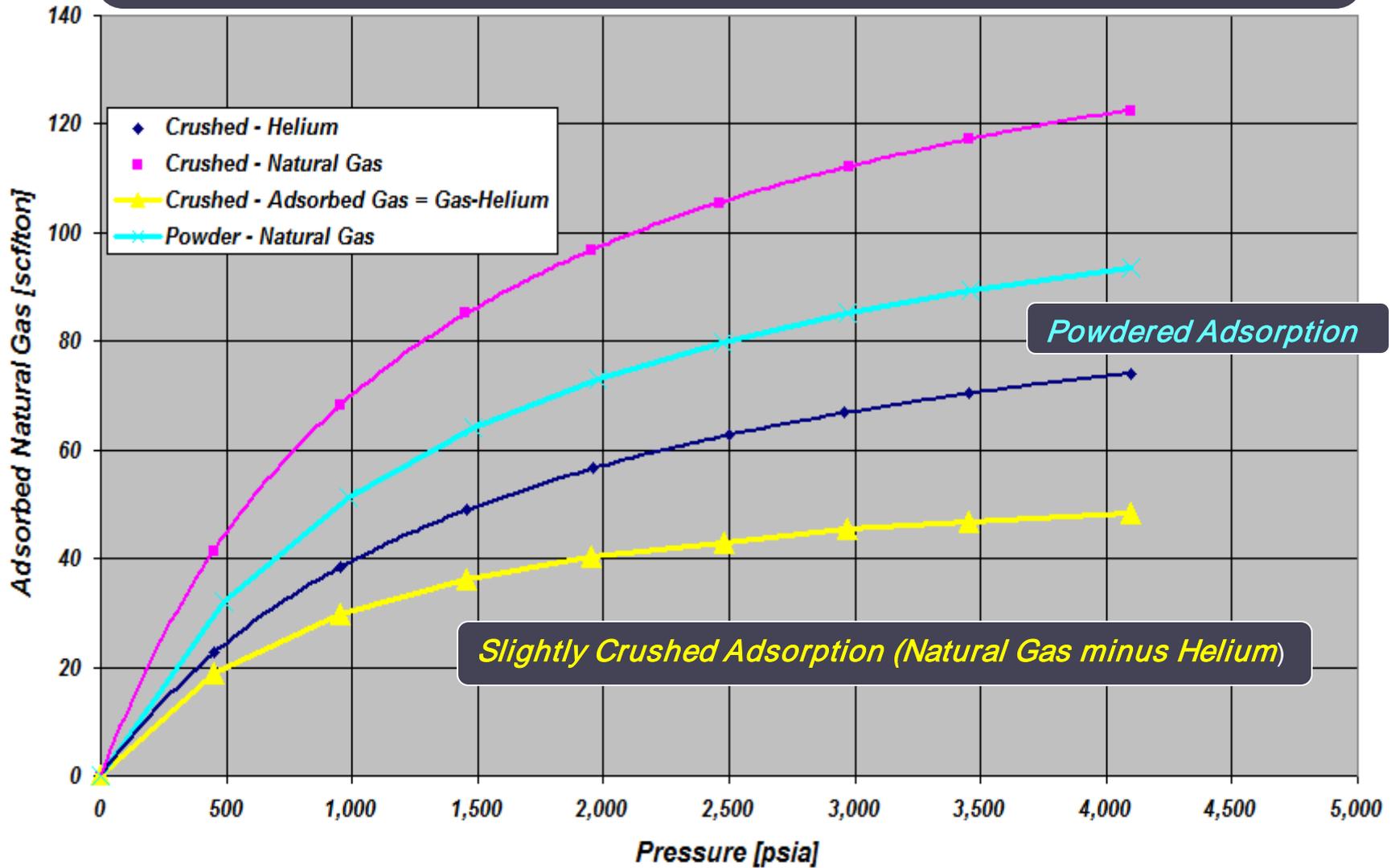
Extracting the shale:

Excessive temperature and solvents will extract the kerogen and generate false porosity leading to over evaluation. **Warning:** It can generate oil where the oil does not exist. If the analysis starts with a shale bulk density and ends with limestone grain density you definitely have a bad data.

**We balance sorption and desorption isotherms to optimize the crushing and extraction procedures (calibrated method).**

# Laboratory Made Adsorption

## Crushed and Powdered Shale Adsorption



# Rock Evaluation Pyrogram

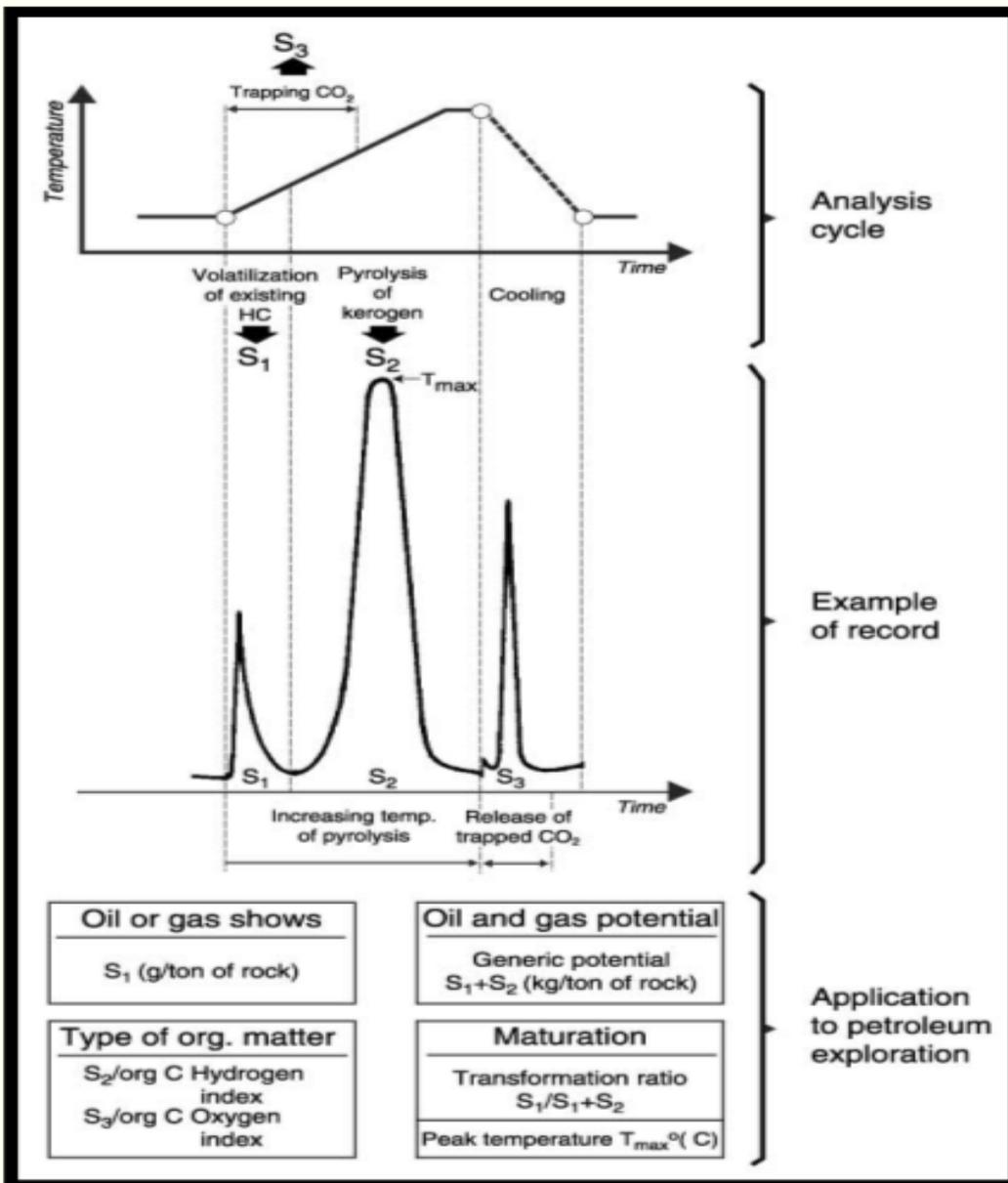
Temperature 300-550°C  
Time 15 minutes

S1: free hydrocarbons  
or (gas and oil) past  
generation.

S2: hydrocarbons  
cracked or future  
generation potential.

Tmax: maturation of the  
organic matter.

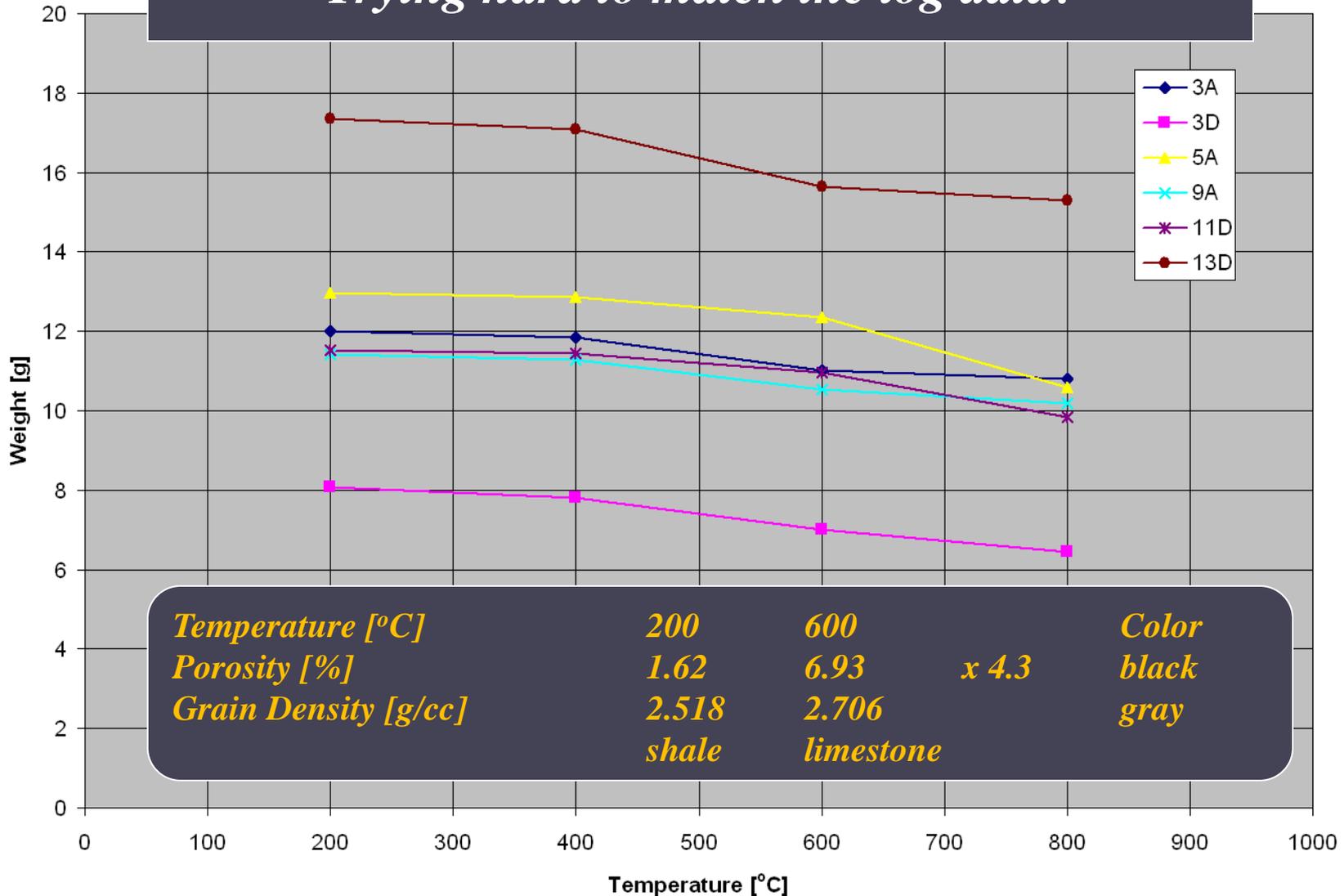
The oil can be extracted  
from the oil shale in Utah  
by heat.



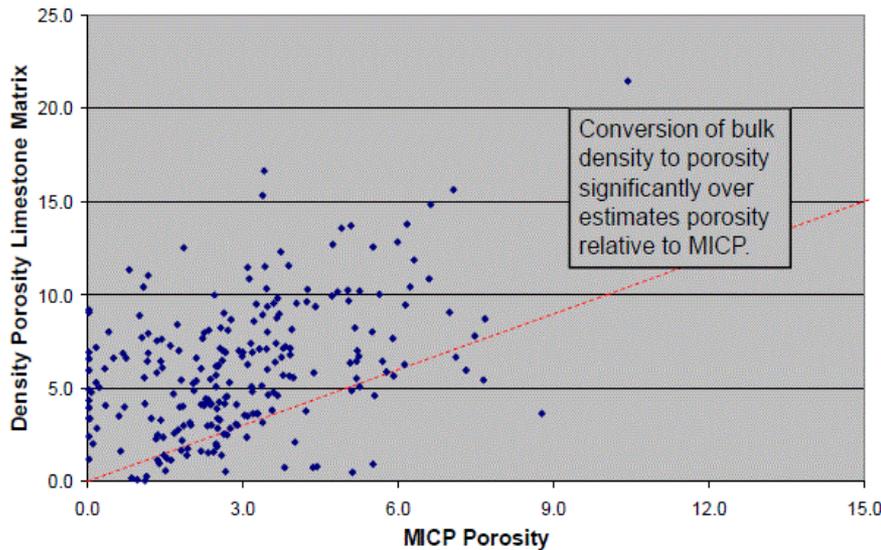
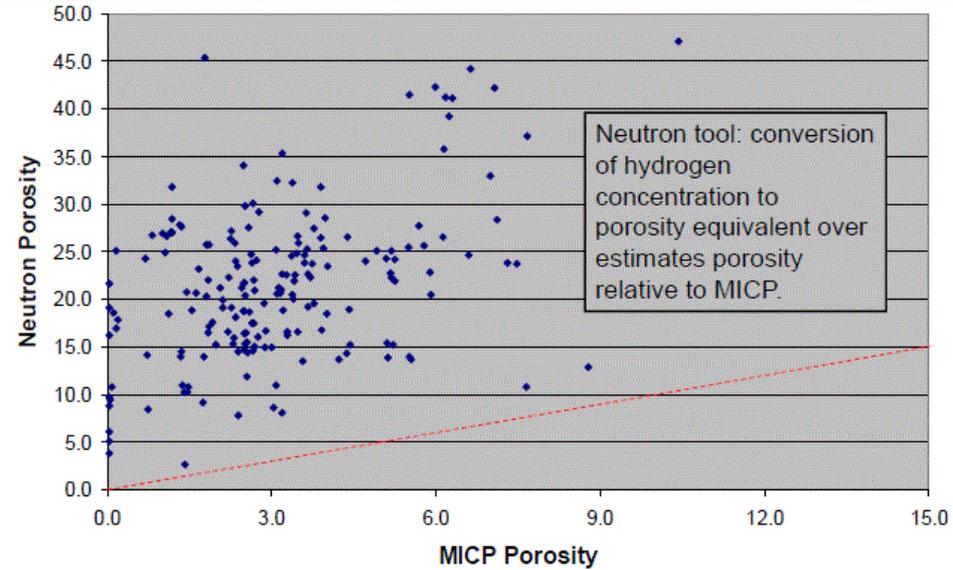
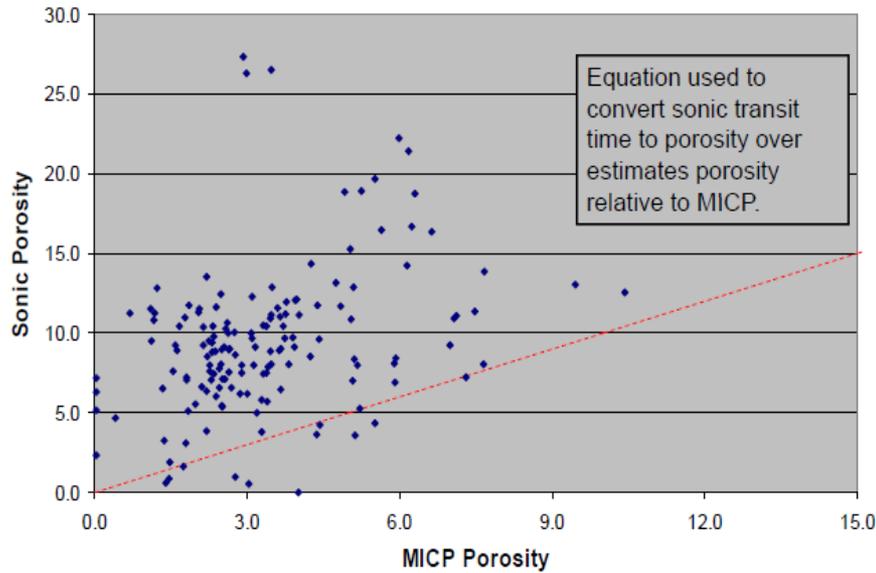
Tissot, B.P., and Welte, D.H., 1984. *Petroleum Formation and Occurrence* (2<sup>nd</sup> ed.): Heidelberg (Springer-Verlag).

# *Laboratory Made Porosity*

## *Trying hard to match the log data!*



# Log Porosity Response



This is a mercury injection porosity study conducted by Kerogen Resources, Inc. on 19 different potential shale plays and a total of 614 samples.

Mercury Injection Capillary Pressure (MICP) A Useful Tool for Improved Understanding of Porosity and Matrix Permeability Distributions in Shale Reservoirs\* by Robert K. Olson and Murray W. Grigg, Kerogen Resources, Inc.

# *Can a sealed generation system be reopened?*

For the first time in 150 years we are drilling horizontally and stage fracturing the source rock.

This massive fracturing opens to the well bore the source rock, the primary reservoir rock, the secondary and tertiary migration paths.

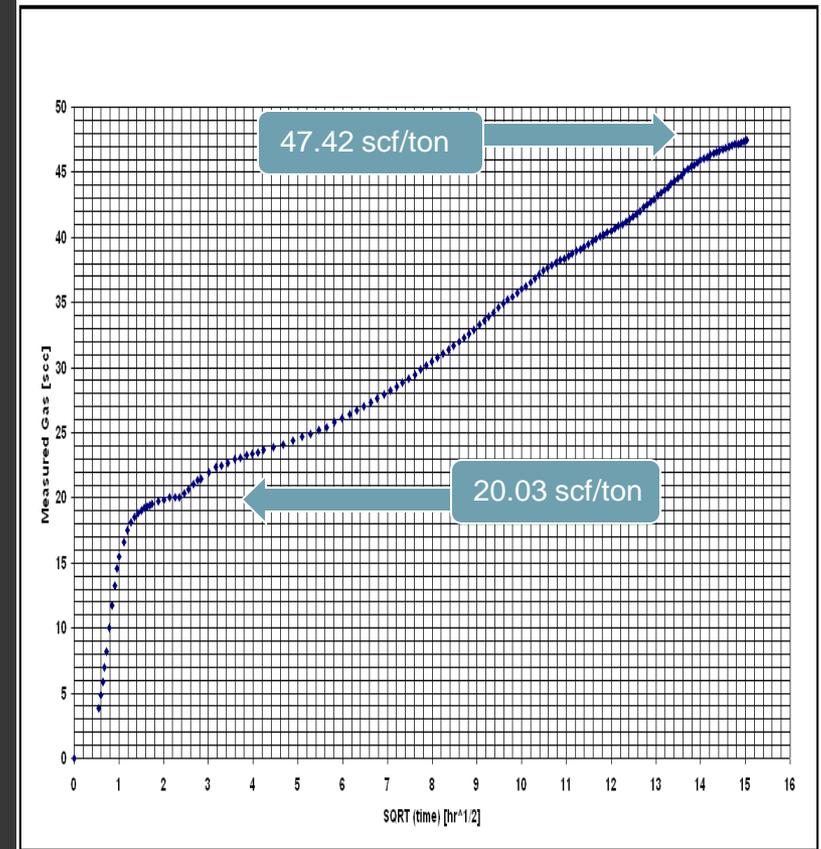
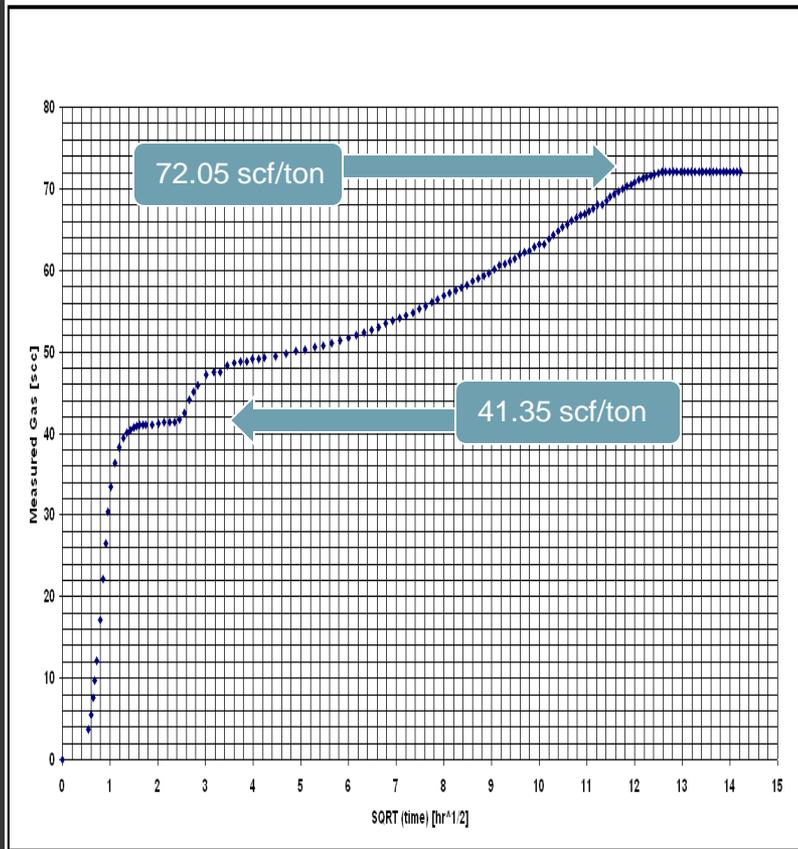
Hydrocarbons are removed from the “sealed-system” and the pressure is reduced. The hydrocarbon generation process slowed by the compaction can resume.

We might be dealing with a **GENERATING RESERVOIR** that can even be stimulated (“hydrogen–catalyst” fracturing job?).

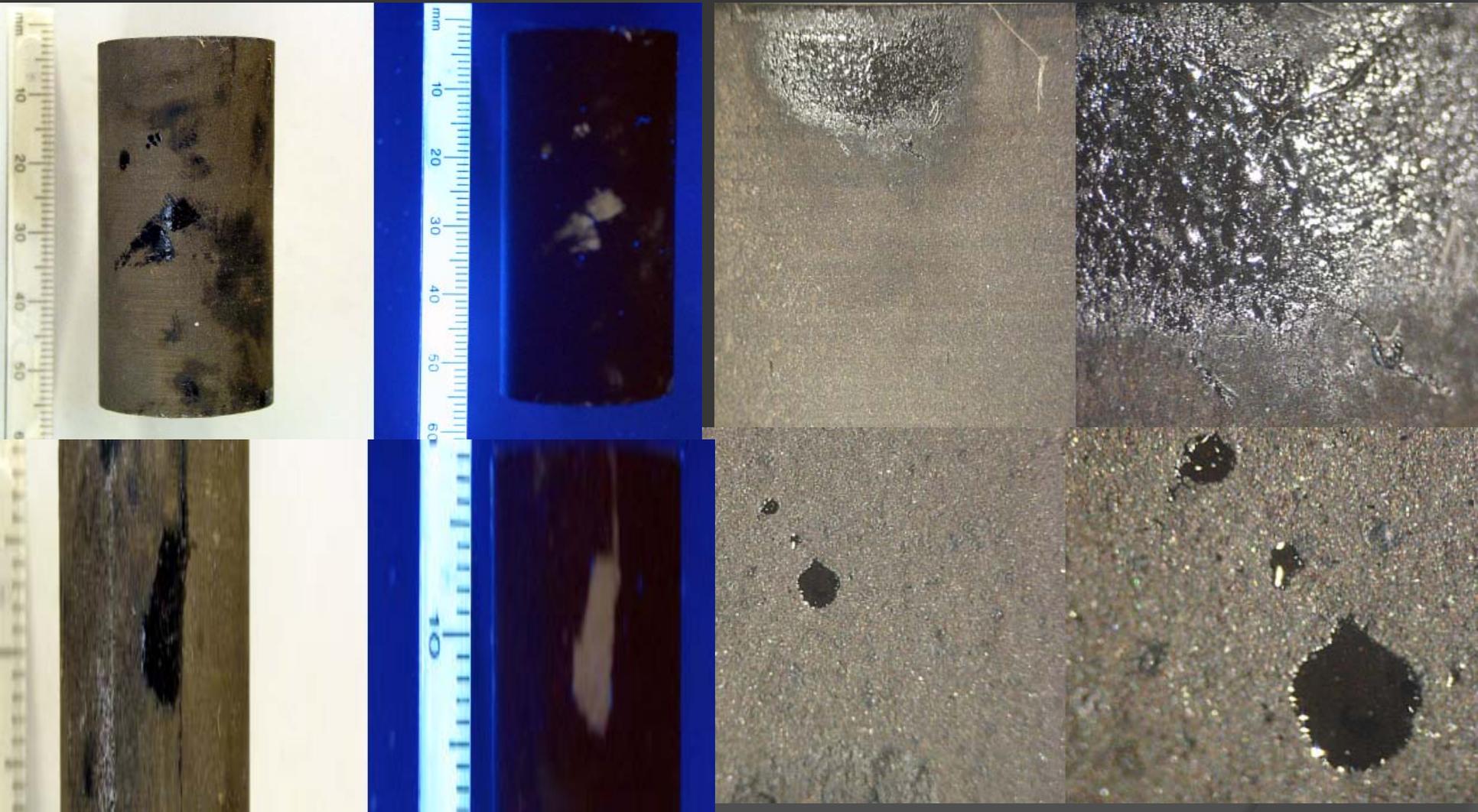
# Unusual Measured Gas Curves

## Gas Generation ?

Reservoir Pressure 3,900 psia, Temperature 200 °F



# *No Stress Laboratory Oil Generation and Associated Fracturing*



# *“Can I have a good shale oil well if my core does not have any matrix fluorescence?”*

- ① The primary reservoir is big, however the reservoir rock seems to be hard to find due to the current sampling techniques and probably to a very large source to reservoir rock ratio (one more reason to measure the desorbed gas).
- ② If we compare the area of a 100 ft long core (100 sqft.) to the area of a large horizontal multi stage hydraulic fracturing operation (1,000,000 sqft.) we realize that the fracture opens 10,000 more area than what we see in the core.
- ③ The same fracturing job is equivalent to 1,000,000 sidewall jobs of 35-40 samples each.

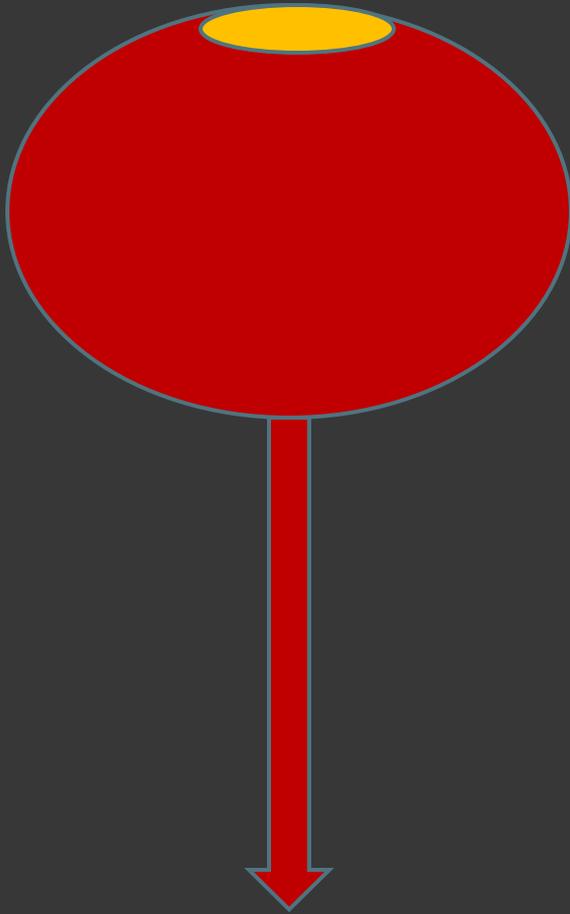
# *Where is the oil and gas produced from?*

## *The Good News!*

Once we fracture the shale source we create a pipeline to the well:

1. Source rock (gas producing). Diffusion and Desorption. Unconventional .
2. Primary reservoir rock or “shale mix” (oil and gas). This has better permeability than the compacted shale. Conventional.
3. Secondary and tertiary migration paths (oil, gas and water). Is it possible to back produce a multitude of small secondary reservoirs with higher porosity and permeability. Conventional.
4. Kerogen current generation will likely be gas (molecular sieving). Very Unconventional ... deserves some serious research.

# *Micro Reservoirs – The “Uncrushed Mini Ore”*



Lets assume we have vertical fractures.

Overpressure with plenty of highly compressed gas. Solution drive dream.

A multitude of micro reservoirs can explain the commercial oil production rates and the associated permeability required for these production rates.

The oil reserves can only be evaluated by pressure build up techniques. The build up test will show much higher permeability than measured by the “GRI method”.

# *Gas Measurements in Shale Oil or Gas ?*

Some of the “expert shale slogans”:

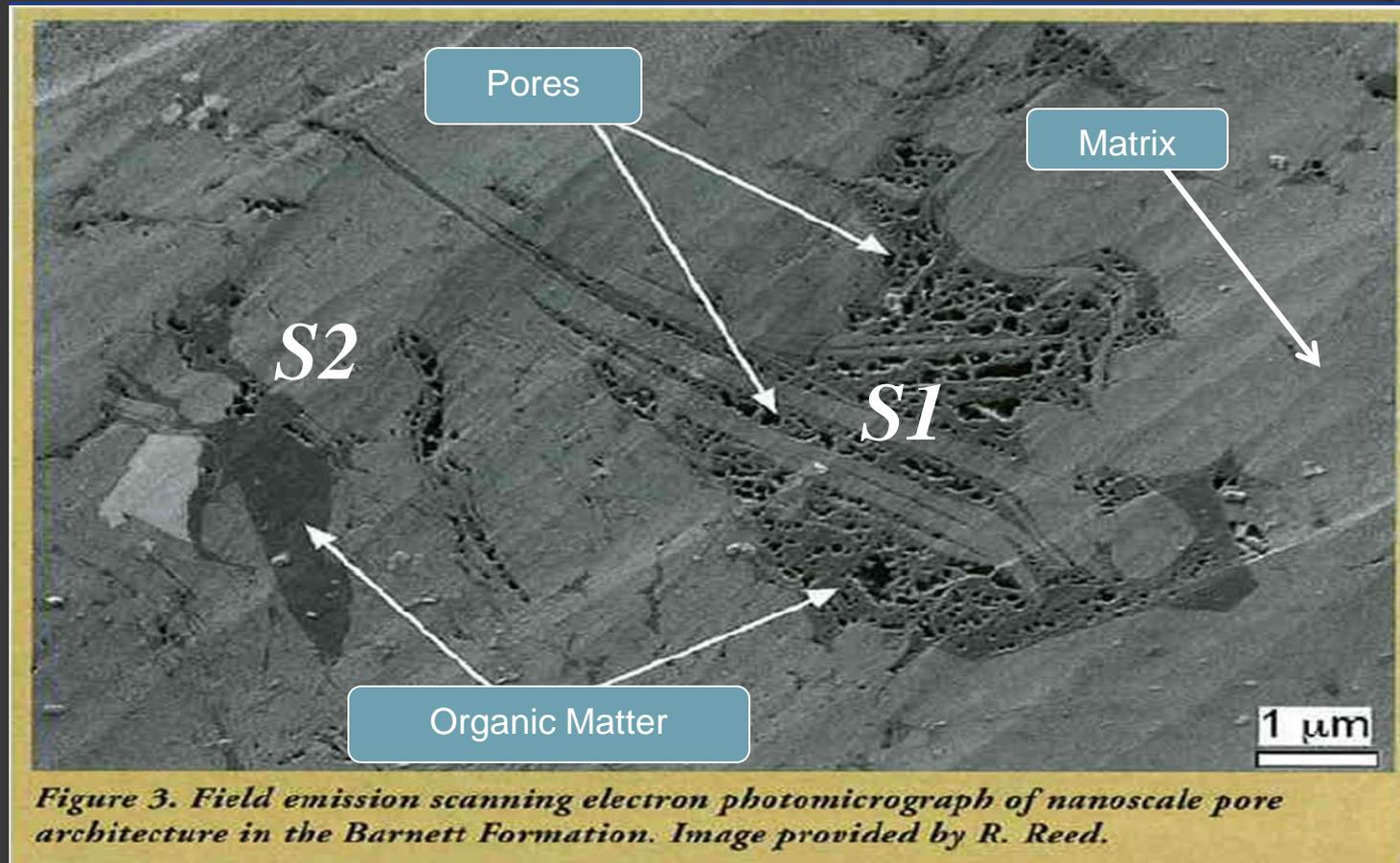
“No need to measure the desorbed gas in shale oil” !!!

“The gas desorption under estimates a good play”

“Gas measurement can kill a good shale prospect due to large lost gas calculations” ???

The shale gas (oil or gas window) is located in the large organic pores responsible for most of the porosity (free gas) and most of the surface area (adsorbed gas). Therefore the accurate automated gas measurements will identify the HIGH HYDROCARBON GENERATION ZONES (the gas is not always proportional to TOC, or S1) is proportional to the total generated hydrocarbons (oil and gas). Only a small residual hydrocarbon saturation is left in the shale that can be extracted and analyzed and finger printed. These measurements are not subject to contamination (diesel, pipe dope etc). The gas measurements permit accurate gas reserve calculations.

# *SEM Picture of a Mature Barnett Shale*



*Figure 3. Field emission scanning electron photomicrograph of nanoscale pore architecture in the Barnett Formation. Image provided by R. Reed.*

The gas is stored (free and adsorbed) in the large organic pores. The gas desorption is ***the only direct and native state measurement*** used to identify the ***high maturity/generation zones*** and ***accurately calculate gas reserves.***

# *New Technology Permits to Verify Lost Gas Calculations*

1. Automated measurements that eliminated all the temperature issues associated with the old CMB technology.
2. Desorption/sorption correlation is used to correct the lost gas and calibrate the crushed rock analysis.
3. Restored state shale analysis can check the lost gas.

*Not measuring the desorption gas is probably a lot worse than drilling an oil well without mud logging.*

# *Restored State Shale Analysis System*



# Quick-Desorption™ Equipment and Software



SCAL Desorption Analysis

Head Gas Measurement... Resume test from a file... Configuration

Sample Units

Sample ID: 1 2 3 4 5 6 7 8 9 10 11

Last Pressure: -0.01 psi -0.01 -0.05 -0.05 -0.06 -0.04 0.00 -0.09 -0.08 -0.10 -0.10

Desorbed Gas: 27.00 scc 40.70 63.95 66.78 88.22 80.62 154.29 120.53 77.25 113.27 121.51

Sample ID: 12 13 14 15 16 17 18 19 20 21 22

Last Pressure: 0.00 psi -0.07 -0.08 -0.09 -0.05 -0.01 -0.02 -0.10 -0.05 -0.01 -0.02

Desorbed Gas: 121.10 scc 127.48 102.02 105.58 81.45 79.63 79.25 109.80 71.75 67.28 66.16

Other Valves: Sample Valve: Closed, Bleed Valve: Closed, Safety on:

Environment: Time: 3/18/2008 9:54:40 AM, Oven Temp: 24.2 °C 75.6 °F, Pressure: 12.77 psia, Atmospheric: 12.77 psia

Job: \_\_\_\_\_, Company: \_\_\_\_\_, Well: \_\_\_\_\_, Program Status: All good

Measuring sample 13 -- Stabilizing... [wait 2s]

SCAL Desorption Analysis

Head Gas Measurement... Resume test from a file... Configuration

Sample Units

Sample ID: 11 22

Last Pressure: -0.10 -0.02

Desorbed Gas: 121.51 66.16

Chamber 19 Details (SCAL Oven Control)

Input: Sample ID: 19, Depth: 9740 ft, Start Sample

Information: Desorbed Gas: 109.80 scc, Last Measure: -0.10/-0.26 psia/scc, Last Temp: 183.40 °F, Hours Elapsed: 25.88, Date Started: 1/22/2008 5:55:34 AM, Status: Off, Data points: 45, Next point: 3/18/2008 9:58:38 AM

Gas desorbed (scc) vs Square root of time elapsed (hours) graph showing a curve that levels off around 110 scc.

Files have been loaded successfully.

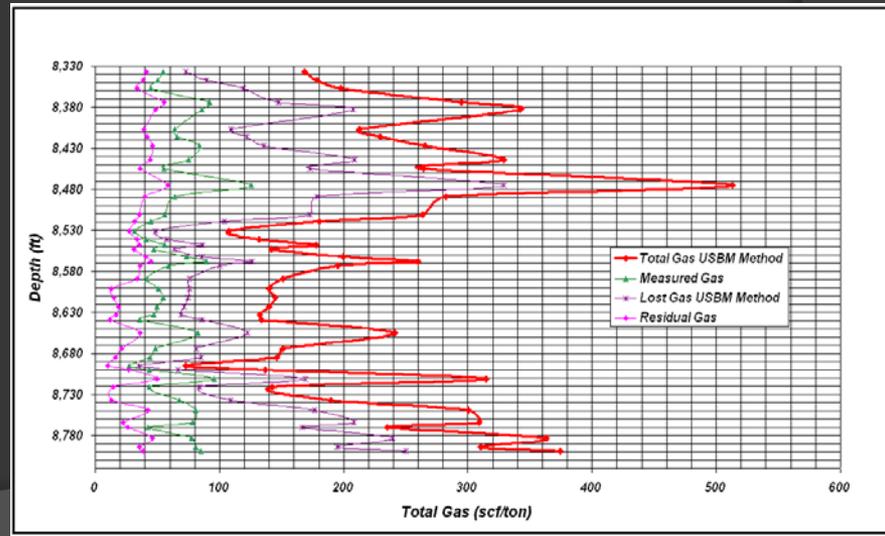
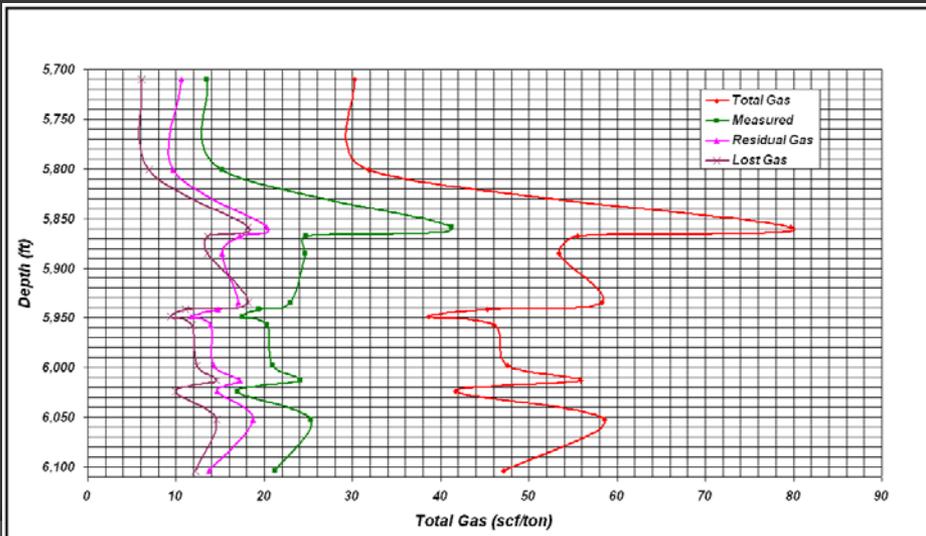
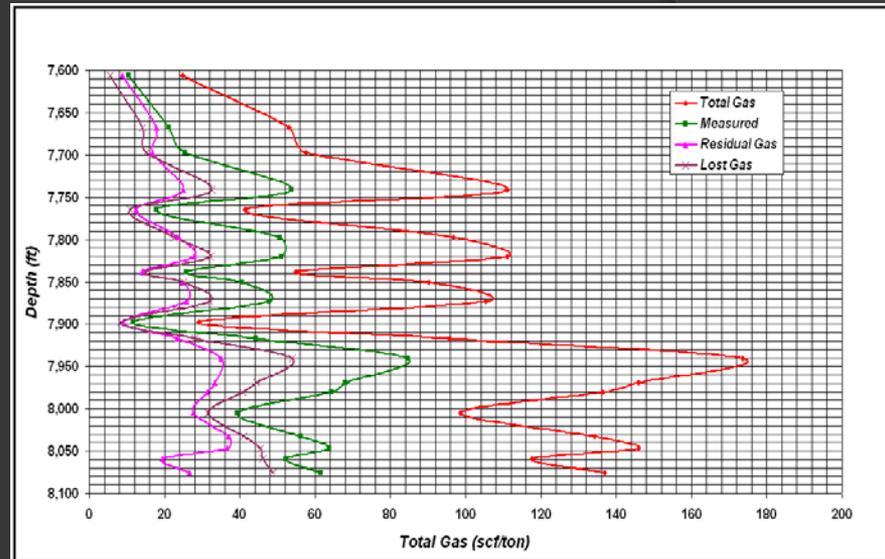
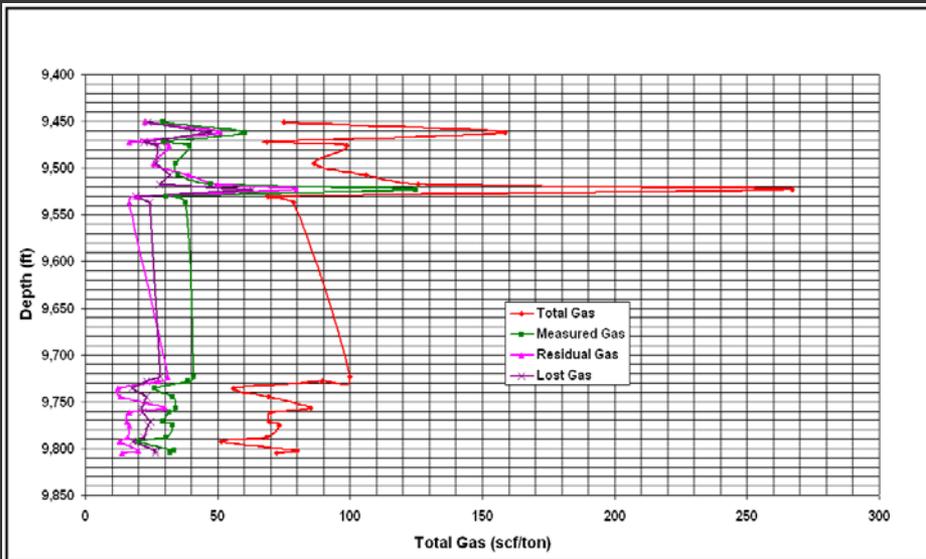


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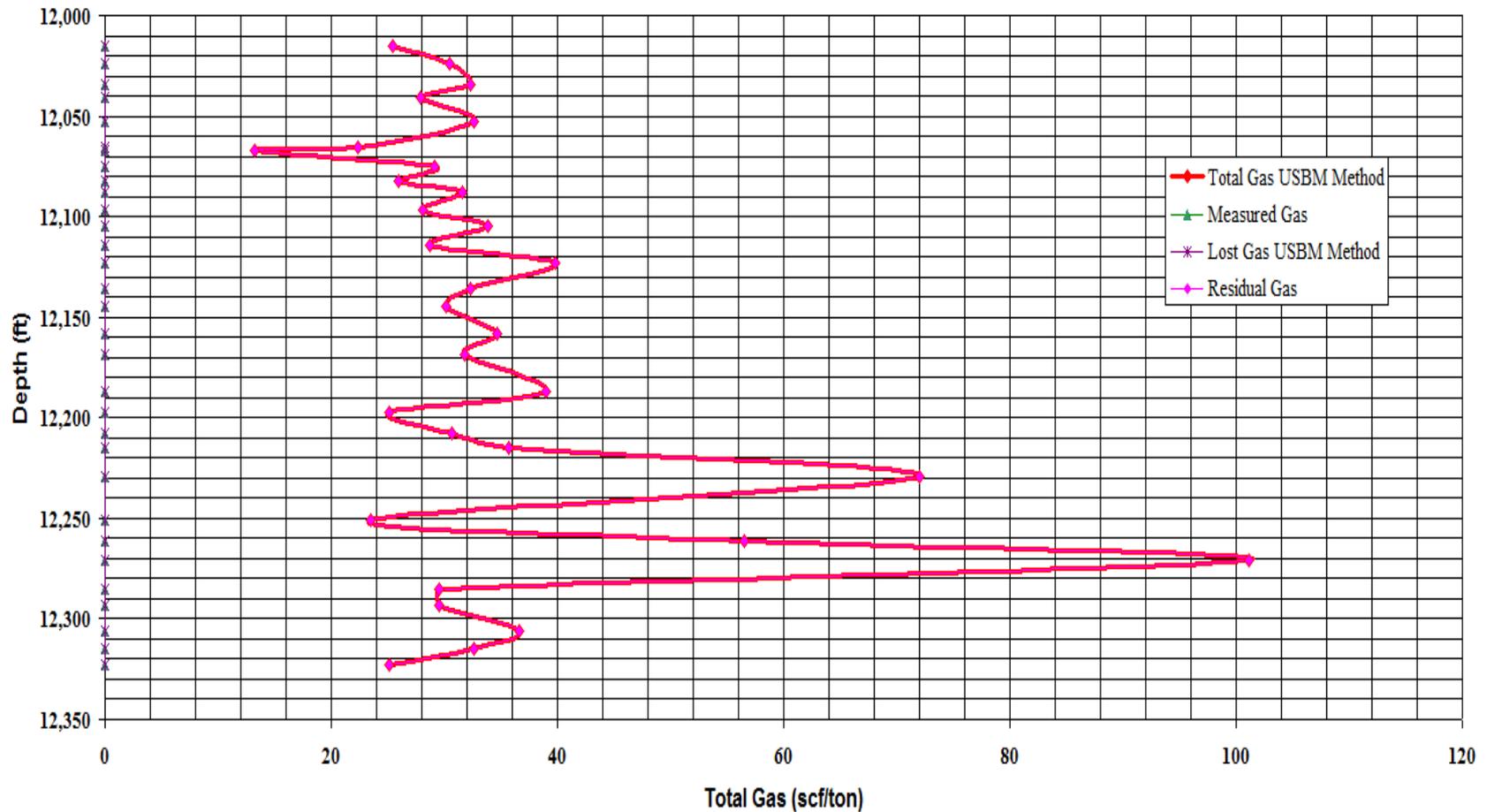
# Quick-Desorption™ Gas Composite Plots

Used for real time horizontal placement decisions



# *Residual<sup>+</sup> Analysis (late desorption)*

## *Eagle Ford Shale*



# *Gas Reserves in Shale are Significant*

$G$  = Gas-in-Place, scf

$A$  = Reservoir Area, acres

$h$  = Thickness, feet

$\rho_c$  = Average In-Situ Shale Density, g/cm<sup>3</sup>

$G_c$  = Average In-Situ Gas Content, scf/ton

$$G = 1359.7 A h \rho_c G_c$$

$$\begin{aligned} \$/\text{acre-ft} &= 1359.7 \times 1 \text{ acre} \times 1 \text{ ft} \times 2.55 \text{ g/cc} \times 100 \text{ scf/ton} / 1000 \text{ scf} \times 4.35 \$/\text{mscf} \\ &= \$1,508/\text{acre-ft} \end{aligned}$$

*The average reservoir gas filled porosity can be calculated using the free gas reserves.*



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# *Why do we have higher gas content in “shale oil” than “shale gas”?*

The gas can diffuse through the shale seal. The methane molecule (.38 nm) is just a bit larger than the water molecule (.30 nm).

Over the geological time required to move the shale source rock from the oil to the gas window significant gas will diffuse through the shale seal. The gas content in the gas window will be smaller than what the same source rock had in the oil window millions of years before.

# *Shale Analysis Recommendations:*

## *For the gas filled source, trap and seal (unconventional reservoir rock):*

Use desorption and sorption isotherms correlation to increase the data confidence.

Minimize the extraction temperatures, the use of hot solvents and sample crushing.

Use native state (uncrushed) and restored state shale analysis technique to check the laboratory procedures.

## *For shale mix (the conventional reservoir rock):*

Use conventional and special core analysis.

Find the shale mix capable of oil and gas storage and transport.

# *Compaction Model Conclusions:*

The shale source is gas saturated even in the oil window.

The oil can not flow in the compacted shale matrix (seal). The oil is produced in a conventional mode from the reservoir rock.

The ratio shale to shale mix is high. Hard to find the “shale mix” fluorescence. This ratio indicate high gas reserves/production even in the “shale oil” prospects.

In conjunction with thermal maturity and basic migration principle the model can explain and position in the right place all types of hydrocarbon accumulations from heavy oil to dry gas.

The model explain very well the overpressure associated with the primary shale reservoirs. It also allows for current time hydrocarbon generation (likely gas).

# *Practical Conclusions:*

The gas desorption is the best direct native state technique available (fast, accurate and economic) to evaluate the shale source in both oil and gas shale plays:

1. it identifies the high maturity/generation zones
2. it provides accurate data for gas reserve calculations
3. is not subject to contamination (pipe dope, diesel, etc.)

The sorption isotherms are used:

1. to predict reservoir performance
2. determine free gas (helium) and calculate average reservoir porosity (use it to calibrate the log response).
3. check and verify lost gas calculations
4. increase the data confidence (sorption/desorption check)

The “shale mix” needs to be sampled and analyzed using conventional core analysis techniques (less expensive).

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