Unconventional Reservoir Stimulation

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Barree & Associates LLC
How Do We Optimize Stimulation Designs?

• Experience
  – Our personal observations
  – Our past history
  – Our expectations of what will be successful

• Diagnostics
  – Pump-in tests
  – Fracture mapping
  – Tracers (chemical and RA)

• Reservoir characterization
  – Log analysis
  – Core studies

• Models
  – Fracture geometry
    • LEFM, planar, 2D, 3D, coupled, shear decoupled?
  – Reservoir production
    • single phase, multiphase, transient, infinite acting, isotropic, Darcy?

Are these transferable from conventional to unconventional?
What Are Unconventional Reservoirs?

- Tight and ultra-tight gas sands
  - Perm less than what? 0.01 md?
  - Composed of
    - Fluvial channels and lenticular sands
  - Anisotropic and discontinuous bodies

- Gas shales
  - What is a shale, anyway?
    - Typically less than 20-30% clay
    - May be quartzitic or carbonaceous
    - Fine grained, small pore-size, high TOC?
  - What is the production mechanism?
    - Darcy’s law for free-gas flow?
    - Diffusion from kerogen?
  - How do we estimate gas content and recovery

- Coalbed Methane
  - Wet or dry coals?
  - What is the permeability of the cleat system?
  - What controls gas content and recovery?
    - Desorption isotherm?
    - De-watering or rate of pressure decline?
Puzzles for Unconventional Reservoir Development

• Pay identification and Gas In-Place
  – Porosity, saturation, TOC, desorption isotherm, net pay, drainage area, aspect ratio

• Permeability
  – Porosity and Sw relations, stress dependence, effects of fractures, capillary effects (perm jail?)

• Stimulation design – frac geometry

• Production forecasting and EUR

• Applying pressure diagnostics

• Managing stimulation damage

• Perforating
Gas Storage v. Frac Placement and Production

• Logs (DTC step-out) help show gas and TOC content
• Areas of high gas content may not be productive
  – Gas is there because it is trapped
  – Gas may be at high pressure, increasing frac gradient
  – High stress and no “natural” fractures means no frac placement or production
• How do we identify best frac placement to contact stored gas?
Log-Derived KH Rarely Works in Unconventional Reservoirs

- Porosity does not correlate well to permeability
  - Pore size and size distribution are needed
- Saturation (or resistivity) may be misleading
  - Distribution of phases, wettability, clay morphology (not volume) may be important
- Small, sparse natural fractures contribute to effective permeability in tight rock
Gas Recovery Mechanisms in Coal

Three “D”s of Coalbed Methane

DESORPTION  DIFFUSION  Darcy Flow

Processing in the Transport of Coalbed Methane Gas

(a) Desorption from Internal Coal Surfaces

(b) Diffusion Through the Matrix and Micropores

(c) Fluid Flow in the Natural Fracture Network

Increasing Size
Porosity of Coals

- **Macropores (> 500 Angstroms)**
  - Space within cleats and natural fractures
  - primarily determines the storage capacity for water
  - considered to vary between 1-5%

- **Micropores (8 to 20 Angstroms)**
  - Capillaries and cavities of molecular dimensions in the coal matrix
  - Essential for gas storage in the adsorbed state
  - Gas is adsorbed on particle surface
  - 98% of methane is typically adsorbed in the micropores
  - Storage capacity is equivalent to
    - 20% porosity sandstone of 100% gas saturation @ the same depth
    - 1 lb of sample Fruitland coal has an estimated internal surface area of 325,000 to 1,000,000sqft
  - A very large volume of methane can be stored in the micropores of coal despite low porosity in the cleat system.
# Typical Size Distribution in Coal Porosity

<table>
<thead>
<tr>
<th>Rank</th>
<th>Pore Size (Angstrom)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>&lt;12 (%), 12–300 (%)</td>
</tr>
<tr>
<td>an</td>
<td>75.0, 13.1</td>
</tr>
<tr>
<td>lvb</td>
<td>73.0, 0.0</td>
</tr>
<tr>
<td>mvb</td>
<td>61.9, 0.0</td>
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<tr>
<td>hvAb</td>
<td>48.5, 0.0</td>
</tr>
<tr>
<td>hvBb</td>
<td>29.9, 45.1</td>
</tr>
<tr>
<td>hvCb</td>
<td>41.8, 38.6</td>
</tr>
<tr>
<td>lig</td>
<td>19.3, 3.5</td>
</tr>
</tbody>
</table>

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(By Permission of the Publishers, Butterworth–Heinemann Ltd.)
Gas Storage & Transportation Mechanism in Coals (contd..)

<table>
<thead>
<tr>
<th>Gas Molecule</th>
<th>Diameter (Angstroms)</th>
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<tbody>
<tr>
<td>Methane (CH$_4$)</td>
<td>4.1</td>
</tr>
<tr>
<td>Carbon Dioxide (CO$_2$)</td>
<td>4.7</td>
</tr>
<tr>
<td>Helium (He)</td>
<td>2.6</td>
</tr>
<tr>
<td>Nitrogen (N$_2$)</td>
<td>3.0</td>
</tr>
<tr>
<td>Water (H$_2$O)</td>
<td>4.1</td>
</tr>
<tr>
<td>Ethane (C$_2$H$_6$)</td>
<td>5.5</td>
</tr>
</tbody>
</table>
Saturation vs Undersaturation

Langmuir Isotherm

\[ V = 435 \times \frac{P}{(P + 714)} \]

Critical Desorption Pressure = 750 psi

Gas content @ Res. Pressure using Langmuir Eqn.

Measured Gas Content @ Initial Reservoir Pressure

Initial Reservoir Pressure = 955 psi
Permeability Change with Shrinkage

- Matrix shrinkage:
  - Coal matrix shrinks as gases desorb and this causes an enlargement of the adjacent cleat spacing – increased permeability
  - Effect increases with adsorbate affinity for coals (i.e. effect is more for the desorption of CO2 than for methane)

*Figure 4.5. Permeability changes with production. (After Harpalani and Schraufnagel) Copyright 1990, Society of Petroleum Engineers.*
Shale-Gas Production Follows a Similar Model

**Shale Production Mechanism.**

- Fractured shale matrix
- Borehole
- Gas movement controlled by pressure
- Gas moves by diffusion
- The diffusion process controls a well’s longevity and its ultimate productivity.

**Shale matrix contains gas stored in 2 ways; free gas and adsorbed gas.** Adsorbed gas molecules adhere to the surface of organics & require a lowering of pressure to initiate desorption. The desorbed gas can then move slowly through the shale matrix by diffusion until it reaches a fracture face. Free gas slowly moves through the micro-pores in the shale matrix by diffusion...? Gas molecules then move through the fracture system by Darcy flow toward the pressure sink provided by the borehole.

(Schad, 2004).
Shale-Gas Content: Free and Adsorbed Gas

3200 ft at 0.42 psi/ft
Effect of Sw of Effective Gas Permeability for Low-Perm Systems

Rocky Mountain Low-permeability Reservoirs - Relative Permeability to Gas
(adjusted for overburden stress and corrected for slippage) (n = 681)

KRG @ 4000 NOB
Byrnes data

modified from Sharley et al., 2004

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Flow Through Smooth Surfaced Fracture, The Cubic Law Equation

\[ Q = 5.11 \times 10^6 \frac{H \Delta P b^3}{L \mu} \]

- \( Q \) = Flow rate (bbl/day)
- \( H \) = Height of fracture (ft)
- \( \Delta P \) = Pressure differential (psi)
- \( b \) = Fracture aperture (in)
- \( L \) = Length of fracture (ft)
- \( \mu \) = Fluid viscosity (cp)
Effect of Fractures on System Permeability for Parallel Flow

Assumed Fracture Aperture = 0.001”

Matrix Perm

<table>
<thead>
<tr>
<th>Fracture Spacing, ft</th>
<th>Folds of Increase over Matrix Perm</th>
</tr>
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<tbody>
<tr>
<td>100.00</td>
<td>100</td>
</tr>
<tr>
<td>90.00</td>
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</tr>
<tr>
<td>80.00</td>
<td>100</td>
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<tr>
<td>70.00</td>
<td>100</td>
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<tr>
<td>60.00</td>
<td>100</td>
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<td>50.00</td>
<td>100</td>
</tr>
<tr>
<td>40.00</td>
<td>100</td>
</tr>
<tr>
<td>30.00</td>
<td>100</td>
</tr>
<tr>
<td>20.00</td>
<td>100</td>
</tr>
<tr>
<td>10.00</td>
<td>100</td>
</tr>
<tr>
<td>0.00</td>
<td>100</td>
</tr>
</tbody>
</table>

K = 0.05
K = 0.01
K = 0.001
K = 0.0001
Core Permeability Changes with Stress Cycling

Example of Stress Cycling or "Seasoning" (from Morrow, et al.5)
Unpropped Fracture Conductivity Loss with Stress

Fracture Conductivity & Pressure Response for 6000' Shale Sample

- Hexane
- 7% KCl
- Rate and Stress Induced Fines Migration

Conductivity, md-ft vs. Time, min

Confining Stress, psi
What Kind of Frac Do We Need?

• Single planar frac
  – Limited surface area
  – All flow passes through a small channel
  – Requires high conductivity
  – Production dependent on frac conductivity and reservoir perm

• Complex (shear) fracture network
  – Large surface area exposed
  – May not be able to connect and drain entire network (load recovery experience)
  – Fracture conductivity may be less important (except near the well, but must be measurable)
  – Production dependent on effective surface area (diffusion dominated)
Complex Fracture Network or Simple Planar Frac?

SPE 90051, Fisher et al, 2004
Simple Model for Complex Transverse Fractures
Increase in Exposed Formation Area with Multiple Fractures
Estimating EUR and Production

- Decline Curve Analysis
  -Produced at capacity
  -Produced at constant BHP
  -Drainage area must remain constant
    - Only valid in boundary-dominated flow (when is that?)

- Material Balance
  -Reservoir fluids in phase equilibrium
  -Accurate fluid properties and production data
  -Reservoir saturations are uniform throughout
  -Reservoir pressure can be represented by a single average value (what is it?)

- Rate-Transient Analysis
  -Homogeneous, isotropic reservoir
  -Single Phase flowing (water and condensate immobile)
  -Isothermal, laminar flow (negligible non-Darcy effects)
  -Gas material balance is valid (no active water drive)

SPE 78695, Cox et al
Establishing time to Pss/BDF

- By using the following equation a reasonable estimate can be made:

\[
t_{pss} = \frac{\phi \mu c_t A}{0.006328k} (t_{DA})_{pss}
\]

Where -

\[
(t_{DA})_{pss} = \frac{r_e^2}{4A}
\]

\[
= \left( \frac{L}{W} + \frac{W}{L} \right)
\]

\[
= \frac{16}{16}
\]

Where:
- \(t_{pss}\): time to Pss/BDF
- \(\phi\): porosity
- \(\mu\): dynamic viscosity
- \(c_t\): turbulence length scale
- \(A\): cross-sectional area
- \(k\): specific energy dissipation rate
- \(r_e\): effective radius
- \(L\): length
- \(W\): width

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How Long Until Decline Curves are Valid?

- ~ 4 days
- ~ 1 month
Evaluation of Techniques for Reserve Forecasting

• Eclipse Simulation Case: channel flow

Drainage Area – 160 acres

Model Parameters

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
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</thead>
<tbody>
<tr>
<td>Formation Top, ft</td>
<td>10,000</td>
</tr>
<tr>
<td>Initial Reservoir Pressure, psi</td>
<td>5,000</td>
</tr>
<tr>
<td>Net Pay, ft</td>
<td>40</td>
</tr>
<tr>
<td>Gas Specific Gravity</td>
<td>0.65</td>
</tr>
<tr>
<td>Effective Gas Perm. Md</td>
<td>0.05</td>
</tr>
<tr>
<td>Fracture Half Length, ft</td>
<td>200</td>
</tr>
<tr>
<td>Fracture Conductivity, md-ft</td>
<td>500</td>
</tr>
</tbody>
</table>

Simulation Controls

• Flowing tubing pressure of 100 Psia
• Economic limit 30 mcfpd and/or 30 years
• Single layer systems
\textbf{EUR results after 180 days of production}

- Hyperbolic exponent > 1 (still transient)
- Time BDF $\sim 5450$ days
- Exponential decline
  - Under-predicts EUR at 180 days
  - Over-predicts EUR after BDF
- SI required to reach avg. press ($P/z$) $> 100$ yrs

\begin{itemize}
  \item Hyperbolic, $Di=1.18$, EUR=448 MMscf
  \item Hyperbolic, $Di=3.03$, EUR=1,720 MMscf
  \item Harmonic, $Di=2.39$, EUR=942 MMscf
  \item Exponential decline
  \item Under-predicts EUR at 180 days
  \item Over-predicts EUR after BDF
  \item SI required to reach avg. press ($P/z$) $> 100$ yrs
\end{itemize}
With transient analysis, you know when BDF occurs.

Infinite Conductivity Fracture in 3.1 to 1 Rectangular Boundary at 180 Days

Finite Conductivity Fracture in 18.6 to 1 Rectangular Boundary Post BDF

Gas in Place = 0.68 BCF - Equivalent Area 27 acres - 180 Days

Gas in Place = 4.06 BCF - Equivalent Area 160 acres - Post BDF
Estimating Reserves

• In unconventional reservoirs it can take years to establish boundary-dominated flow
• An accurate pressure buildup for material balance (P/z) can take years
• Do reservoirs controlled by desorption ever behave as volumetric systems?
• Only rate-transient analysis can give insights into:
  – Drainage aspect ratio
  – Transient flow regimes
  – Effectiveness of stimulation
Pressure Diagnostics

- G-function and log-log flow-regime plots for conventional and unconventional reservoirs
- Does injected fluid (water) enter pores for coal and shale to establish a reservoir pressure transient?
- Can we diagnose fracture system extent or conductivity from falloff behavior?
G-function in a “Shale” that looks like a reservoir

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - G Function

7 days of falloff with a possible closure at G>12
Post-Closure Reservoir Transient in a “Shale” Test

GohWin Pumping Diagnostic Analysis Toolkit

Minifrac - Log Log

BH ISIP = 10664 psi

Time (0 = 9.216667)

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Coal Injection Test:
Is this a fracture test?
Coal Injection

G-Function Interpretation

Minifrac - G Function

Bottom Hole ISIP – 7216 psi (0.91 psi/ft)

Closure Pressure – 5939 psi (0.75 psi/ft)
Coal Injection Log-Log Plot

Minifrac - Log Log

- Delta Bottom Hole Calc Pressure (psi)
- Delta Smoothed Pressure (psi)
- Smoothed Adaptive 1st Derivative (psi/mm)
- Adaptive DT dDP/dDT (psi)

BH ISIP = 7216 psi

Time (0 = 424.466667)

Table:

<table>
<thead>
<tr>
<th>Time</th>
<th>DBHCP</th>
<th>DSP</th>
<th>FE</th>
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<tbody>
<tr>
<td>1</td>
<td>Closure</td>
<td>5.33</td>
<td>1277</td>
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</tbody>
</table>

Notes:

- [m < -0.501]
- [(Y = 122.8)]
Simulation of Radial Injection into Reservoir (const perm)

Reservoir Injection - No fracture

Job Data

Minifrac Events

<table>
<thead>
<tr>
<th>Time</th>
<th>TP</th>
<th>SR</th>
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<tbody>
<tr>
<td>Start</td>
<td>00:02:36</td>
<td>27332</td>
</tr>
<tr>
<td>Shut in</td>
<td>00:51:03</td>
<td>16584</td>
</tr>
<tr>
<td>Stop</td>
<td>06:18:46</td>
<td>8394</td>
</tr>
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</table>

Diagram showing tubing pressure and shut rate over time.
Radial Injection Simulation G-Function

Minifrac - G Function

<table>
<thead>
<tr>
<th>Tubing Pressure (psi)</th>
<th>A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Smoothed Pressure (psi)</td>
<td>A</td>
</tr>
<tr>
<td>Smoothed Adaptive 1st Derivative (psi)</td>
<td>D</td>
</tr>
<tr>
<td>Smoothed Adaptive G*dP/dG (psi)</td>
<td>D</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Time</th>
<th>TP</th>
<th>SP</th>
<th>DP</th>
<th>FE</th>
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<tbody>
<tr>
<td>Closure</td>
<td>0.32</td>
<td>7944</td>
<td>8119</td>
<td>8572</td>
</tr>
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GohWin v1.6.5
01-Aug-08 08:32
Radial Injection Simulation Log-Log

Minifrac - Log Log

- Delta Bottom Hole Calc Pressure (psi)
- Delta Smoothed Pressure (psi)
- Smoothed Adaptive 1st Derivative (psi/min)
- Adaptive DTdDP/dDT (psi)

Time | DBHCP | DSP | FE
--- | --- | --- | ---
1 | 6.38 | 7536 | 7246 | 11.27

BH ISIP = 16624 psi

Time (0 = 51.05)

Graph showing pressure vs. time with specific points and calculations:
- Point (1652, 1282) with a calculated slope of m = 0.994
- Point (X = 1166.7)
Coal Injection: BH Gauge ISIP

GohWin Pumping Diagnostic Analysis Toolkit
Job Data

Minifrac Events

<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Time</td>
<td>BGP</td>
<td>CR</td>
</tr>
<tr>
<td>1</td>
<td>Start 5/17/2007 00:00:09</td>
<td>3191</td>
<td>2.528</td>
</tr>
<tr>
<td>2</td>
<td>Shut In 5/17/2007 00:05:14</td>
<td>4936</td>
<td>0.118</td>
</tr>
<tr>
<td>3</td>
<td>Stop 5/17/2007 08:07:01</td>
<td>2604</td>
<td>0.050</td>
</tr>
</tbody>
</table>

BH Gauge Pressure (psi) vs. Clean Rate (bpm)

ISIP = 1.14 psi/ft
Early-time G-function in a deep coal

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - G Function

First closure at >1 psi/ft
Late-time G-function for deep coal

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - G Function

<table>
<thead>
<tr>
<th>Time</th>
<th>BGP</th>
<th>SP</th>
<th>DP</th>
<th>FE</th>
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<tr>
<td>1</td>
<td>5.90</td>
<td>3220</td>
<td>3225</td>
<td>1619</td>
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</table>

(A, D)

(BH Gauge Pressure (psi) A
Smoothed Pressure (psi) A
1st Derivative (psi) D
G*dP/dG (psi) D)

 Closure (6,388, 535.7)

(0,000,0)}

\( m = 83.89 \)
Log-Log Flow Regime Plot for Deep Coal

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - Log Log

BH ISIP = 4839 psi

No definable reservoir transient flow regimes

<table>
<thead>
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<th>Time</th>
<th>DBHCP</th>
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<tr>
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<td>44.05</td>
<td>1619</td>
</tr>
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</table>
Pressure Diagnostics in Unconventional Reservoirs

• Information may be hidden in the details
• Some show reservoir transient behavior and some don’t
• Some show extended fracture/fissure transients with no actual closure after days of falloff
• Work is needed to correlate these signatures to production response
• The tests may suggest when shear-enhanced fracturing is warranted and when fracture conductivity is required
Conclusions

• Conventional and unconventional reservoirs may have very different stimulation needs
• Subtleties of pressure diagnostics need to be linked to well performance for unconventional reservoirs
• We need to accept that unconventional reservoir deliverability is not controlled by matrix properties (although storage is)
• We need to define and differentiate when exposed surface area is more important than conductivity
• Fluid, proppant, rate, and volume of design must be based on a specific stimulation goal
• We need to better understand and account for time-dependence of damage and conductivity
• We need to appreciate the time dependence and importance of drainage area and aspect ratio on EUR and stimulation economics