Reservoir Modeling in Unconventional Liquid Reservoirs

Dr. David Schechter
Reservoir Model Team

- Tom Blasingame (RTA/PTA)
- Akhil Datta-Gupta (Simulation, Streamlines)
- Eduardo Gildin (Lattice Boltzman Simulation)
- Mike King (PTA/Upscaling)
- John Killough (Simulation Development)
- Duane McVay (Uncertainty Analysis)
- George Moridis (Simulation/TOUGH)
- Hadi Naserabadi (Lattice Boltzman Simulation)
Akhil Datta-Gupta & Mike King

• Background: Diffusive Time of Flight
• Simulation Method: Coordinate Transformation
• Triple-continuum Approach for Shale Modeling
• Fractured Shale Well Model – Pressure/Rate Diagnosis
• Conclusions
Pressure ‘Front’ Propagation

• **Radius of Investigation (ROI): For a Homogeneous Field**
  Radius of Investigation is the propagation distance of the ‘peak’ pressure disturbance for an impulse source or sink (Lee 1982).

\[ r = \sqrt{\frac{4kt}{\phi \mu c_t}} \]

• **Generalization of ROI : For Heterogeneous Fields** the Eikonal equation generalizes the ROI (Datta-Gupta et al., 2011)

\[ \sqrt{\frac{k(x)}{\phi(x) \mu c_t}} |\nabla \tau(x)| = 1 \]

Travel time of pressure front

Speed of pressure front propagation
• Novel method based on DTOF which allows to transform a 3-D depletion problem with wells + fracture + reservoir heterogeneity to an equivalent 1-D problem

• Can be applied as a foundation to rapid reservoir simulation where it is demonstrated with a triple porosity model to capture matrix to fracture to hydraulic fracture to well transport

• Applied to direct analysis of field production to determine underlying geometry of the drainage volume and instantaneous recovery ratio
Pressure Front Propagation From Fast Marching Solution

15s to run FMM
Simulation Workflow and Benchmarking

Spatial Heterogeneity

Permeability

FMM

Diffusive Time of Flight

Drainage Volume

Drainage pore volume (ft³)

Numerical Flow Simulation

Rate Calculation

Well

BHP Calculation

1-D \( \tau \)-coordinate

Assign \( \Delta V_p \)

\( \tau_1 \quad \tau_2 \quad \tau_{N-1} \quad \tau_N \)
CPU Comparison

- Significant gain in computational efficiency
  - Dual Porosity Model, Horizontal well with 15 HF
  - BHP constraint
  - 20 years simulation

<table>
<thead>
<tr>
<th></th>
<th>Cell number (millions)</th>
<th>CPU Finite Difference (s)</th>
<th>CPU FMM (s)</th>
<th>Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>1.03</td>
<td>574.7</td>
<td>13.1</td>
<td>43.87</td>
</tr>
<tr>
<td>High kf</td>
<td>1.03</td>
<td>557.9</td>
<td>13.1</td>
<td>42.59</td>
</tr>
<tr>
<td>High km</td>
<td>1.03</td>
<td>691.62</td>
<td>13.2</td>
<td>52.40</td>
</tr>
<tr>
<td>Long xf</td>
<td>1.03</td>
<td>586.2</td>
<td>13.4</td>
<td>43.75</td>
</tr>
<tr>
<td>More stage</td>
<td>1.23</td>
<td>628</td>
<td>16.4</td>
<td>38.29</td>
</tr>
</tbody>
</table>
Motivation: Shale Heterogeneities

Multi-scale Heterogeneities in Shale:
- Natural fractures
- Multistage hydraulic fractures
- Nanoscale porosity/permeability
- Adsorption / Desorption
- Kerogen / Organic matter

Modeling Multistage Hydraulic Fractures

Dual-Porosity to Triple-Continuum

Naturally Fractured Reservoirs
Discrete Fracture Network

Dual-Porosity Model (Warren and Root 1963)

Convection
Fracture → Fracture → Fracture → Well
Matrix → Matrix → Matrix

Convection-Knudsen Diffusion
Fracture → Fracture → Fracture → Well
Matrix → Matrix → Matrix

Shale Rock with Hydraulic Fractures

Diffusion

Convection
Fracture → Fracture → Fracture → Well
Matrix → Matrix → Matrix

Kerogen

Rock compaction
Fracture → Fracture → Fracture → Well
Matrix → Matrix → Matrix

Reservoir Simulation Symposium
Fracture-Matrix Mass Transfer

\[ \text{Total Mass Transfer} = \text{Darcy} + \text{Slippage} + \text{Knudsen Diff.} \]

\[ J_{\text{total}} = J_C + J_{Kn} \]

\[ = \rho \frac{k_{\infty}}{\mu} F \nabla P + D_m \nabla \rho \]

\[ = \rho \frac{1}{\mu} \left( k_{\infty} F + c_g \mu D_m \right) \nabla P \]

\[ = \rho \frac{1}{\mu} k_{\text{app}} \nabla P \]

- **Apparent Permeability Model**
  (Javadvour et al. 2006, Swami et al. 2013)

\[ k_{\text{app}} = k_{\infty} F + c_g \mu D_m \]

\[ k_{\text{app}} = \frac{\phi_m}{\delta} \left[ \frac{r^2}{8} + \left( \frac{8RT}{\pi M_w} \right)^{0.5} \frac{\mu g r}{8P} \left( \frac{2}{\alpha} - 1 \right) + \frac{2rc_g \mu g}{3} \left( \frac{8RT}{\pi M_w} \right)^{0.5} \right] \]

- Darcy Perm.
- Increment by Slip flow
- Increment by Knudsen diff.

Reservoir Simulation Symposium
Kerogen-Matrix Mass Transfer

Total Mass Transfer = Molecular Diffusion

\[ J_{\text{total}} = J_{\text{Diff}} \]

Fick’s First Law

\[ J_{\text{Diff}} = -\sigma \rho_{g,sc} D_c (C_m - C_K) \]

- \( D_c \): Diffusion coefficient
- \( C_m \): Gas concentration in matrix
- \( C_K \): Gas concentration in Kerogen

Kerogen Gas Diffusion

Accumulation in Matrix
- Adsorbed gas
- Free gas

Langmuir Isotherm

\[ C_m = V_L \frac{P}{P_L + P} \]

- \( V_L \): Langmuir volume (scf/rcf)
- \( P_L \): Langmuir pressure (psia)
12-stage hydraulic fractures (Perm. x 10,000)

Table 2.2 – Reservoir properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir Initial pressure</td>
<td>(psia)</td>
<td>1,500</td>
</tr>
<tr>
<td>Temperature</td>
<td>(degF)</td>
<td>250</td>
</tr>
<tr>
<td>Matrix Porosity</td>
<td>(fraction)</td>
<td>0.1</td>
</tr>
<tr>
<td>Rock compressibility</td>
<td>(1/psi)</td>
<td>1 x 10^{-6}</td>
</tr>
<tr>
<td>Fracture-matrix shale factor</td>
<td>(1/ft²)</td>
<td>0.15</td>
</tr>
<tr>
<td>Langmuir pressure</td>
<td>(psi)</td>
<td>650</td>
</tr>
<tr>
<td>Langmuir volume</td>
<td>(scf/rcf)</td>
<td>7.13</td>
</tr>
<tr>
<td>Kerogen Diffusion coefficient</td>
<td>(ft/day)</td>
<td>0.02</td>
</tr>
<tr>
<td>Kerogen-matrix shape factor</td>
<td>(1/ft²)</td>
<td>0.15</td>
</tr>
</tbody>
</table>

Rock compaction in fracture system

![Graph showing the relationship between Pressure (psia) and Multiplier for Permeability and Porosity Multiplier]
Pressure Transient Behaviors with Constant Rate Production

Pressure Transient

<table>
<thead>
<tr>
<th>Time, days</th>
<th>Δ(mp)</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 nm</td>
<td>1.0E+08</td>
</tr>
<tr>
<td>50 nm</td>
<td>1.0E+07</td>
</tr>
<tr>
<td>20 nm</td>
<td>1.0E+06</td>
</tr>
<tr>
<td>10 nm</td>
<td>1.0E+05</td>
</tr>
<tr>
<td>5 nm</td>
<td>1.0E+04</td>
</tr>
</tbody>
</table>

Pressure derivative

<table>
<thead>
<tr>
<th>Time, days</th>
<th>Δ'(mp)</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 nm</td>
<td>1.0E+08</td>
</tr>
<tr>
<td>50 nm</td>
<td>1.0E+07</td>
</tr>
<tr>
<td>20 nm</td>
<td>1.0E+06</td>
</tr>
<tr>
<td>10 nm</td>
<td>1.0E+05</td>
</tr>
<tr>
<td>5 nm</td>
<td>1.0E+04</td>
</tr>
</tbody>
</table>

Transition region from fracture transient to total system transient
• This study combines the effect of:
  
  - **Wettability alteration** (Contact Angle experiments)
  - **Interfacial Tension alteration** (IFT measurement)
  - **Spontaneous Imbibition** (Imbibition experiments)
  - **Penetration magnitude** (CT scan technology)

• Evaluate and compare the efficiency of surfactants in altering wettability and recovering hydrocarbons from shale cores.
### Permian Basin ULR

#### XRD analysis

<table>
<thead>
<tr>
<th></th>
<th>Experiment 1</th>
<th>Experiment 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>41%</td>
<td>13.1%</td>
</tr>
<tr>
<td>Clays</td>
<td>27%</td>
<td>15.1%</td>
</tr>
<tr>
<td>Calcite</td>
<td>13%</td>
<td>46.2%</td>
</tr>
<tr>
<td>Dolomite</td>
<td>6%</td>
<td>19.6%</td>
</tr>
<tr>
<td>Feldspar</td>
<td>11%</td>
<td>3.5%</td>
</tr>
<tr>
<td>Illite/mica</td>
<td>95.8%</td>
<td>94.3%</td>
</tr>
<tr>
<td>Smectite</td>
<td>4.2%</td>
<td>5.7%</td>
</tr>
</tbody>
</table>

**TOC = 5 - 6%**

**Black shale**

[Logo: CRISMAN INSTITUTE FOR PETROLEUM RESEARCH]

[Logo: BERG-HUGHES CENTER]
Anionic surfactant reduced IFT in two orders of magnitude.
IFT values ULR

IFT (mN/m)

- Frac Water: 21.8 mN/m
- Nonionic A: 16.7 mN/m, 13.2 mN/m, 9.8 mN/m
- Nonionic B: 16.2 mN/m, 10.3 mN/m, 9.8 mN/m
- Anionic: 7.9 mN/m, 0.5 mN/m, 0.4 mN/m
- Nonionic+Ionic: 7.9 mN/m, 4.7 mN/m, 4.0 mN/m

0.2 gpt, 1 gpt, 2 gpt
Contact Angle Well HA (Siliceous)

Intermediate wet → Water wet
Contact Angle Well HA (Carbonate)

Intermediate wet → Water wet
Zeta Potential

- Higher magnitude for surfactants compared to frac water
- Difference in the nature (sign) is due to the type of surfactant
- Improved stability of the aqueous film on rock surface meaning more stable water-wet state
Spontaneous Imbibition

Changes in densities, fluid movements and imbibition

Oil Recovery vs. time
Using the CT scanner

Siliceous cores
- Before
- After
  - Anionic
  - Nonionic

Low CT  High CT

Carbonaceous cores
- Before
- After
  - Water
  - Anionic
  - Nonionic

Low CT  High CT
Using the CT scanner

Siliceous cores

Carbonaceous cores

Penetration Magnitude

\[ \text{Penetration Magnitude} = CT_{th} - CT_{base} \]

CRISMAN INSTITUTE FOR PETROLEUM RESEARCH

\[ \text{Penetration Magnitude} = CT_{th} - CT_{base} \]
Lithology and Surfactant type effect

Siliceous cores:
Best performance by anionic surfactant

Carbonate cores:
Best performance by nonionic surfactant
Gas Injection Experimental Procedure

Shale cores were soaked in CO₂

A high permeability media was provided to store CO₂ in contact with the shale cores

Core holder was placed horizontally

Schematic of cores packing
CO₂ Injection - Results

Oil Recovery

0.4 cm³ of oil was recovered!!

OIP = Core Volume * φ * (1 − Swi)

---

### TABLE 1– EXPERIMENTAL CONDITIONS AND CORE DIMENSIONS

<table>
<thead>
<tr>
<th>Scenario</th>
<th>1st Experiment</th>
<th>2nd Experiment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Temperature, °F</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td>Pressure, psi</td>
<td>3000</td>
</tr>
<tr>
<td>Core number</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Core diameter, cm</td>
<td>2.53</td>
<td>2.53</td>
</tr>
<tr>
<td>Core length, cm</td>
<td>3.97</td>
<td>3.48</td>
</tr>
<tr>
<td>Core bulk volume, cm³</td>
<td>19.94</td>
<td>17.50</td>
</tr>
</tbody>
</table>

---

### SCENARIOS FOR OIL RECOVERY

<table>
<thead>
<tr>
<th>Porosity, %</th>
<th>1st Experiment</th>
<th>2nd Experiment</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>6</td>
<td>3</td>
</tr>
<tr>
<td>6</td>
<td>3</td>
<td>3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Water saturation, %</th>
<th>1st Experiment</th>
<th>2nd Experiment</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>30</td>
<td>0</td>
</tr>
<tr>
<td>30</td>
<td>0</td>
<td>30</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Recovery factor, %</th>
<th>1st Experiment</th>
<th>2nd Experiment</th>
</tr>
</thead>
<tbody>
<tr>
<td>18</td>
<td>25</td>
<td>36</td>
</tr>
<tr>
<td>51</td>
<td>28</td>
<td>39</td>
</tr>
<tr>
<td>19</td>
<td>39</td>
<td>55</td>
</tr>
</tbody>
</table>
Results

CT Images
Shale sidewall core 2

First Experiment
Test conditions: 3000 psi, 150 F
Objective

• Development, meshing (specially designed grid algorithms) and simulation of Discrete Fracture Networks (DFN) from core, log and micro-seismic data
CT images under different confining pressure

Fracture area decreases with increasing confining pressure
Fracture Aperture
Log-Normal Distribution

![Graph showing log-normal distribution of fracture aperture with mean and standard deviation values for different stress levels.]

- **Mean = 138.656, σ = 150.33** for 1500 Psi
- **Mean = 157.418, σ = 162.395** for 1000 Psi
- **Mean = 197.997, σ = 172.573** for 500 Psi
- **Mean = 370.527, σ = 211.772** for No stress
Objective 1

- Propose a methodology to Generate Discrete Fracture Networks (DFN) using microseismic and Core Data
Objective 2

- Improve natural fracture characterization by estimation of source mechanisms: fracture orientation and rupture mode.
Background Information: Horizontal Core

- Silty Sand Formation
- Naturally Fractured
- Core data from a horizontal well

Shear mineralized fracture ~ N 35 deg (Set 1)

Tensile open fractures E-W (Set 2)
Hydraulic Fracture Job

- 15 stages
- 1 vertical monitoring array of 12 receivers
Example 1: Stage 5

- 71 reported events

- The strike of green events has already been determined by the inverse modeling
- Strike for all other events are determined stochastically
Modeling and Simulation: Micro-Seismic Constrained DFN

- Unstructured PEBI grid generation
Applications

- Microseismic-constrained workflow

- **History Matching** - the best DFN realization

Collaboration with *Edith Sotelo Gamboa*
Applications

- Fractal-based unconventional workflow

• Fracture Conductivity - ceramic proppant vs. sand proppant

For more, refer to SPE 169866
Two NF Realizations

[Image of two NF realizations with grid and red patterns]
Pressure Distribution at End of Huff n’ Puff Simulation
Cumulative Production
Conclusions

• Surfactants can alter wettability in shale samples from intermediate to water-wet

• Anionic surfactants showed better performance than nonionic surfactants in changing contact angle and reducing IFT

• We observe that surfactants are capable of displacing oil from cores by submerging them in surfactant solutions demonstrating spontaneous imbibition

• CT scan results showed that surfactants have higher penetration magnitudes than fluids without surfactants
Conclusions

• Oil production was accomplished by soaking shale cores with CO₂ at 3000 psi and 1600 psi. CT imaging was done during the course of the experiment revealing changes inside the sidewall cores.

• In order to better estimate the OIP and RF, and for future numerical simulation, we first need better understanding of our rock properties.

• Gas flood performed on new core sample confirmed that the core has negligible permeability. Therefore, a systematic process that characterizes our rock samples needs to be designed.

• Gas injection in preserved sidewall core clearly recover incremental oil.
Conclusions

• We have established that micro-seismic data can be used to constrain generation of Discrete Fracture Networks

• Once DFN’s are generated we can apply optimized gridding algorithms to create unstructured grids of naturally fractured rock in communication with hydraulic fractures

• These grids can be simulated to understand primary depletion, chemical additives for completion and chemical flooding

• The generated grids can also be used to understand compositional simulation of gas injection in complicated fracture networks
Conclusions

• We proposed a triple-continuum approach for modeling fractured shale gas reservoirs based on diffusive time of flight as spatial coordinate

• The proposed approach is analogous to streamline simulation and can result in substantial savings in computation time

• We incorporated relevant shale gas physics and flow characteristics in a triple-continuum model
  – Slippage/Knudsen diffusion become significant in the matrix and can appreciably change the permeability under low pressure conditions
  – The matrix (Nanopores) supplies the fracture with a large amount of gas in early-time, while the Kerogen supports sustained gas production for long-term
Additional Slides
Muralidharan, Putra and Schechter (2003)
Aperture distribution follows lognormal distribution at all stress conditions
Reservoir Scale Modeling – Development of a General Unconventional Reservoir Utility (GURU) – Compositional Unconventional Research Platform – Killough Research Group

1. From Micro-Scale To Reservoir Scale Modeling

**Micro-Scale Model** (kerogen distribution, Darcy flow, desorption, and Fickian/Knudsen diffusion)


**Reservoir-Scale in Dual Porosity Model** (Couple apparent matrix permeability from Micro-Scale Dual Porosity Model)

2. Multiple Porosity Modeling
(Extend dual porosity model into multiple porosity model)

**Multiple Porosity Model**

CRISMAN INSTITUTE FOR PETROLEUM RESEARCH

BERG-HUGHES CENTER
Example 2 : Stage 8

Realization 1
Example 2: Stage 8

Realization 2
Future work: Sensitivity and Uncertainty Analysis

- Each DFN realization is different
- Parameters of distributions describing fracture properties have an associated uncertainty, thus

The proposed study will:
- Find the most sensitive parameters that affect fracture complexity (area of connected fractures)
- Evaluate the effect of the uncertainty of these parameters on fracture complexity
It is generally accepted that Microseismicity is a:

- **Subtle earth tremor induced by reactivation of plane of weaknesses** (Natural fractures)

Along HF open faces (fluid leak off): Not Connected Network

An event location reveals that there is a natural fracture passing through this point

Near HF tip: Connected Network
Conceptual Model: Hydraulic Fracture Path

- Follows Hill’s (1977) conceptual model for earthquake swarms
- Fluid induced tensile cracks connecting shear–reactivated natural fractures
Modified Hydraulic fracture pattern

Stair case pattern due to fracture energy requirements
Wu and Olson (2014)
Source Mechanisms

- From the waveforms, find the fracture orientation and rapture mode by amplitude-inverse modeling

- Each microseismic event induces micro-earth tremors that are recorded at each receiver as waveforms

- P and S amplitudes are picked from the waveforms as input data for the inverse modeling

- The outputs of the inverse modeling are:
  - Fracture Orientation: strike ($\Phi$), dip ($\delta$)
  - Fracture Rupture mode: rake ($\lambda$), slope ($\alpha$)
Limitations

- For the inverse modeling to work only events whose waveforms present both P and S arrivals can be processed.

- With a Single vertical array of receivers the inverse modeling can not find an solution. An additional assumption has to be provided:

  In this case we assumed that the strike of the fractures were known since we have the core information. The modeling helped to find to which of the 2 sets the event belonged (E-W or 35 deg N).
DFN Generation WorkFlow

- Main assumption: For Each Microseismic (MS) event there is a single natural fracture passing through

  - Perturbation of MS event locations
  - Estimation of 2D fracture density from fracture spacing (core data)
  - Random selection of events belonging to either fracture set
  - The fracture set is fixed for those events whose preferred plane solution was found
  - Generation of Natural fractures
  - Generation of Complex HF paths
  - Length following a power law (E-W set)
    Length from source radius (N 35 deg. set)
  - Orientations following a Fisher Distribution (based on core data)
Fracture Aperture and Conductivity

- Natural Fractures:
  - Log normal distributed
  - Corrected by normal stress and surface roughness

@ 2500 psi
Mean C ~ 4 md-ft
Hydraulic Fractures: Conductivity derived from experimental data

Interpolation of conductivity
Vs normal stress and proppant concentration
Stage 5 - DFN

47 connected DFN to the HF

- Histogram and normal distribution of connected DFN to HF (500 realizations)
- Mean = 36.5
- Std = 7.9
Stage 5 – DFN- PEBI grids

• DFN for Stage 5 with 71 MS events (after Edith Sotelo Gamboa)
• Fracture networks with connected NFs + HFs