Is Our Carbonate Reservoir Fractured or Not?*

Patrick Corbett

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Posted November 10, 2014

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Abstract

Information on fractured reservoirs is often controversial. Engineers see lost circulation, negative skin and fracture well test signatures. Geologists see only matrix properties in their cores. Geologists see fractures but engineers see only radial flow on their well tests. In many cases, the two lines of information concur and the evidence is uncontroversial. In other cases the information is not so clear. Engineering data is notoriously non-unique and because carbonate reservoirs have such high heterogeneity – over 30 possible forms of porosity – and many ways this can be connected (or not!) this is a real challenge. What is seen by geologists in small cores may not be seen in larger well tests. Alternatively what is 'seen' in the well tests may bear no link to the observed rocks. It is in these circumstances that the two specialists need to come together and understand each other’s points of view and the limitations of each other's data. This requires specialist knowledge with geoengineering insights to try and reach unification of geological and engineering models. All models are wrong – but the one both disciplines agree with is probably useful.

Selected References


Websites


Is our Carbonate Reservoir Fractured or Not?

Patrick Corbett
BG Group Professor
Carbonate Petroleum Geoengineering
Fractured or not?

Reservoir Engineering – YES
- Well test response
- Finite conductivity Fracture
- Negative skin
- Cross-flow

Geology – NO
- No core
- No image logs
- No losses

Three “fractured” reservoir well tests
Fractured or not?

Å Reservoir Engineering – YES
- Well test response
- Double porosity response
- Negative skin

Å Geology – NO or maybe
- No naturally fractured core
- No open fractures on image logs
- No significant losses

Two “fractured” reservoir well tests
Fractured or not?

Å Reservoir Engineering – NO
  - Well test response
  - Radial flow
  - No skin

Å Geology – YES
  - Core
  - Image Log
  - Drilling losses

Leckenby et al, 2007,
Soc Spec Publ 270, “Fractured Reservoirs”
Fractures occur where you least expect them!
Nelson (1999) defined four types of fractured reservoirs:

Type I: Fractures provide the essential storage capacity and permeability in a reservoir. The matrix has little porosity or permeability.

Type II: Rock matrix provides the essential storage capacity and fractures provide the essential permeability in a reservoir. The rock matrix has low permeability, but may have low, moderate, or even high porosity.

Type III: Fractures provide a permeability assist in an already economically producible reservoir that has good matrix porosity and permeability.

Type IV: Fractures do not provide significant additional storage capacity or permeability in an already producible reservoir, but instead create anisotropy. (Barriers to Flow)
Fractured Reservoir Evaluation

**Integration of:**
- Lost Circulation (Drilling/Mud Log)
- Core Recovery (Mud Log)
- Core slabs
- Log Interpretation methods
  - Sonic/Total Gas
  - Caliper/Sonic porosity
- Borehole Image logs
- Fracture Identification Log
- Well test interpretation (Double Porosity)
- Modified Lorenz Plot (Core poroperms)
- Production Log Interpretation (PLT)

(From Etminan and Sefti, 2008)
Fracture Permeability Calculations

Heriot-Watt Notes

\[ k = 54,000,000 \times \text{Width}^{(\text{^2})} \text{ (inches)} \]
Fracture 0.001” >>>> 54,000mD

Crain:

\[
\begin{align*}
\text{PHIfrac} &= 0.001 \times Wf \times Df \times KF1 \\
\text{Kfrac} &= 833 \times 10^2 \times Wf^{2} \times Df \times KF1 \\
\text{PHIfrac} &= \text{fracture porosity (fractional)} \\
Df &= \text{fracture frequency (fractures per meter)} \\
Wf &= \text{fracture aperture (millimeters)} \\
Kfrac &= \text{fracture permeability (millidarcies)}
\end{align*}
\]


NUMERICAL EXAMPLE

Df = 1 fracture per meter
Wf = 1.0 millimeters

\[
\begin{align*}
\text{PHIfrac} &= 0.001 \times 1 \times 1 = 0.001 \text{ fractional (0.1%)} \\
\text{Kfrac} &= 833 \times 100 \times 1^2 \times 1 \times 1 = 83300 \text{ millidarcies}
\end{align*}
\]

KF1 = number of main fracture directions

= 1 for sub-horizontal or sub-vertical
= 2 for orthogonal sub-vertical
= 3 for chaotic or brecciated
Fracture Permeability Calculations

Glover:

| Solution Channel | \( k = 0.2 \times 10^8 \times d^2 \) | \( k \) = permeability (D) \\
| Fractures        | \( k = \frac{0.544 \times 10^8}{W^2} \) | \( d \) = channel diameter (inches) \\
|                 | \( k \) = permeability (D) \\
|                 | \( h \) = fracture width (inches) \\
|                 | \( w \) = fracture aperture (inches) |

http://www2.ggl.ulaval.ca/personnel/paglover/CD%20Contents/GGL-66565%20Petrophysics%20English/Chapter%2003.PDF

Note the additional effect of fracture curvature, roughness and presence of asperities
Fracture Permeability Calculations

Geiger:

\[ k_f \ (m^2) = a(m)^2/12 \]
Fracture Permeability Calculations

<table>
<thead>
<tr>
<th>Fracture permeability equations</th>
<th>Aperture (inch)</th>
<th>Aperture (mm)</th>
<th>Aperture (m)</th>
<th>k (mD)</th>
<th>k(D)</th>
</tr>
</thead>
<tbody>
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<td>1</td>
<td>0.001</td>
<td>83333.33333</td>
<td>83.33333333</td>
</tr>
</tbody>
</table>

Applicable to plane parallel fractures at the core plug scale (ignoring the rock!)
Sample PET 8, Morro do Chaves

Horizontal Plug (#50)
Porosity = 6.5%
Permeability = 0.145mD

Vertical Plug (#51)
Porosity = 5.8%
Permeability = 0.031mD
Split into two plugs

Horizontal Plug
Porosity = 6.5%
Permeability = 0.145mD

Assume Vertical Plug Properties
Porosity = 5.8%
Permeability = 0.031mD

Estimate Properties
Porosity = ???%
Permeability = ???mD
Whatever the plug 50a perm, can’t make total 0.145mD!!

Plug 50a

Plug 50b

Estimate Properties
Porosity = ???
Permeability = ???

Assume Vertical Plug Properties
Porosity = 5.8%
Permeability = 0.031mD

<table>
<thead>
<tr>
<th></th>
<th>Plug 50a</th>
<th>Plug 50b</th>
<th>Plug 50</th>
<th>Fract</th>
<th>Matrix</th>
<th>Harm Av</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>7.2</td>
<td>5.8</td>
<td>6.5</td>
<td>1.4</td>
<td>5.8</td>
<td></td>
</tr>
<tr>
<td>Permeability (mD)</td>
<td>100000</td>
<td>0.031</td>
<td>0.145</td>
<td>100000</td>
<td>0.031</td>
<td>0.0620000</td>
</tr>
</tbody>
</table>
Gary Couples’ “Unconnected Highways”

Nice multi-lane highway that does not have any traffic – cuz it doesn’t connect to anything!
### Fractures in Whole Core

#### Core
- Length: 1000 mm
- Diameter: 100 mm
- Volume: 7853982 cu mm

#### Fracture
- Angle: 45 deg
- Width: 1 mm
- Diameter: 100 mm
- Volume: 15708 cu mm

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Matrix Porosity</td>
<td>0</td>
</tr>
<tr>
<td>Total Porosity</td>
<td>0.002</td>
</tr>
<tr>
<td>Fracture porosity</td>
<td>0.002 Dec</td>
</tr>
<tr>
<td>Matrix Permeability</td>
<td>0 mD</td>
</tr>
<tr>
<td>Total Permeability</td>
<td>83 mDm</td>
</tr>
<tr>
<td>Fracture Permeability</td>
<td>83333 mD</td>
</tr>
</tbody>
</table>
Fracture Equations are simplification

Don’t take into account:
1. The interaction between fracture and pore matrix
2. Aperture variation
3. Fracture wall roughness
4. Aperture spatial correlation

Jiang et al, 2013
Fractures from logs

Å Estimate using Sonic and Neutron Porosity logs
  ï Sonic >> Matrix Porosity
  ï Neutron >> Total Matrix plus Fracture Porosity
  ï Determine Fracture Porosity

Å Estimate using Aguilera Method
  ï Estimate Matrix Porosity and Cementation (m) exponent
  ï Determine Matrix and Reservoir Formation Factor
  ï Determine Fracture Porosity

Source: Pritchard, 2013
Fractures from logs (Cont.)

- Estimate from Shallow and Deep Resistivity logs
  - You know $1/R_{xo}$ and $1/R_t$
  - Determine Porosity Partitioning Coefficient
  - Determine Fracture Porosity (% of $\Phi_T$ held by fractures)

- Other methods
  - Caliper log
  - Gamma Ray (Heavy mineral veins)
  - Array Sonic (Chevrons)
  - Fracture Identification Logs (FIL)
  - Image logs

Source: Pritchard, 2013
Fractures using well test (2)

2 Classic ‘V’ shaped derivative

“\(\omega\) defines the contribution of the fissure systems to the total storativity”

“\(\lambda\) defines the ability of the matrix blocks to produce to the system”

Nelson Type II Fractures
Double Porosity System
Fracture Reservoir Recovery (1)

Fracture Reservoir recovery mechanisms

Storage Classification

From a storage point of view the fractures can be classified as being of Type A, B, or C. Many reservoirs that would otherwise be

Schematic Distribution of Fractured Reservoir Types

TABLE 2: Typical oil recoveries from naturally fractured reservoirs as a per cent of original oil in place.

<table>
<thead>
<tr>
<th>RECOVERY MECHANISM</th>
<th>A</th>
<th>B</th>
<th>C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depletion Drive</td>
<td>10-20</td>
<td>20-30</td>
<td>30-35</td>
</tr>
<tr>
<td>Depletion Drive plus Gas Injection</td>
<td>15-23</td>
<td>25-30</td>
<td>30-40</td>
</tr>
<tr>
<td>Depletion Drive plus Water Injection</td>
<td>20-35</td>
<td>30-40</td>
<td>45-55</td>
</tr>
<tr>
<td>Depletion Drive plus Water Inj plus Gas Inj</td>
<td>25-40</td>
<td>30-45</td>
<td>45-65</td>
</tr>
<tr>
<td>Gravity Segregation with Counterflow</td>
<td>40-50</td>
<td>50-60</td>
<td>&gt;60</td>
</tr>
<tr>
<td>Depletion Drive plus Water Drive</td>
<td>30-40</td>
<td>50-60</td>
<td>50-60</td>
</tr>
<tr>
<td>Depletion Drive plus Gas cap</td>
<td>15-25</td>
<td>25-35</td>
<td>35-40</td>
</tr>
<tr>
<td>Depletion Drive plus Gas Cap plus Water Drive</td>
<td>35-45</td>
<td>45-65</td>
<td>55-65</td>
</tr>
</tbody>
</table>

TABLE 3: Typical gas recoveries from naturally fractured reservoirs as a per cent of original gas in place.

<table>
<thead>
<tr>
<th>RECOVERY MECHANISM</th>
<th>A</th>
<th>B</th>
<th>C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Without Water Drive</td>
<td>70-90</td>
<td>80-99</td>
<td>&gt;90</td>
</tr>
<tr>
<td>With Moderate Water Drive</td>
<td>50-60</td>
<td>60-70</td>
<td>70-80</td>
</tr>
<tr>
<td>With Moderate Water Drive and Compression</td>
<td>20-30</td>
<td>30-40</td>
<td>40-50</td>
</tr>
<tr>
<td>With Water Strong Drive</td>
<td>15-25</td>
<td>25-35</td>
<td>35-45</td>
</tr>
</tbody>
</table>

Roberto Aguliers
Journal of Canadian Petroleum Technology
July 1999, Volume 38, No. 7

Recovery increases >>>>>>>>

Source: Pritchard, 2013
Fractured Reservoir Recovery (2)
Some Definitions

• Single Porosity – Matrix only

• Classic “Double Porosity” - Fractured Reservoirs

• “Double Matrix” Porosity Reservoirs – New awareness

• “Triple Porosity” - Fractured Double Matrix Reservoirs or Triple Matrix Porosity

• Numerical (geological) well testing – emerging standard workflow – “Geotesting”

• Petroleum Geoengineering – integrated geo-petrophys-eng workflow

Corbett et al., 2010, Petroleum Geoscience
Double Matrix Geological Model

Rock Types (Martin et al. 1997)

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Pore Throat Size (µm)</th>
<th>Mean K (mD)</th>
<th>Swi</th>
<th>Sro</th>
<th>Rock Fabric</th>
</tr>
</thead>
<tbody>
<tr>
<td>Macroport</td>
<td>2 - 10</td>
<td>250</td>
<td>0.15</td>
<td>0.2</td>
<td>Grainstone oolitic</td>
</tr>
<tr>
<td>Mesoport</td>
<td>0.5 - 2</td>
<td>50</td>
<td>0.25</td>
<td>0.3</td>
<td>Grainstone oolitic</td>
</tr>
<tr>
<td>Microport</td>
<td>&lt; 2</td>
<td>5</td>
<td>0.35</td>
<td>0.35</td>
<td>Grainstone oolitic</td>
</tr>
</tbody>
</table>

Morales, 2009

Ahr, 2008
Double Matrix Porosity

- Lorenz coefficient ($Lc$) is related to local heterogeneity (close to the well), and the pressure response investigates bigger volume of reservoir.
Double Matrix Porosity

- Lorenz coefficient (Lc) is related to local heterogeneity (close to the well), and the pressure response investigates bigger volume of reservoir.
What is Well Testing?

- Production of a limited amount of fluid from the reservoir
  \[
  \frac{\partial^2 P}{\partial x^2} \eta_x + \frac{\partial^2 P}{\partial y^2} \eta_y + \frac{\partial^2 P}{\partial z^2} \eta_z = \frac{\partial P}{\partial t}
  \]

- Pressure changes in space and time controlled by the Diffusivity equation
  \[
  \eta_j = \frac{k_j}{\phi \mu C_t}, \ j = x, y, z
  \]

- Hydraulic diffusivity - Is this a constant

(From Corbett, DISC, 2009, after Zheng)
Well Test Skin

Difference between pressure at shut-in and after 1hr (on the Horner straight line) (Bourdarot, 1998)

\[ \Delta P_{\text{skin}} = P_2 - P_1 \]

-ve : Reduced pressure drop at wellbore
+ve : Extra pressure drop at wellbore

(From Corbett, 2009, DISC)
Pressure derivative plots
(in an rectangular sand pit)

Flow regimes 1 >> 2 >> 3

(From Corbett, DISC, 2009, after Zheng)
The rate that the pressure change moves away from the well is a function of the diffusivity ($k/\mu\phi c$).

(From Corbett, DISC, 2009)
Finite Conductivity Fracture

Infinite Acting Fracture ½ slope and separation of 2

From Horne, 1995
Numerical Well Test Workflow

Forward problem where the model is built and then the pressure response is simulated and analyzed.
Geological Model

- Very low permeability rock type (microport) was distributed as background.
- Good permeability rock type (macroport) was distributed as objects (ellipse and quart ellipse).
Geological Model

- Porosity was set constant value for the whole model
- Permeability was distributed using Sequential Gaussian Simulation (SGS) - variogram (spherical type)
- Very low permeability was distributed in the background rock type
- High permeability was distributed in the objects
Flow Simulation (Eclipse Model)

- Model size 1000m x 1000m x 50m
- Grid size 10mx10mx1.67m ; Cells NX=100, NY=100, NZ=30 (300,000 cells)
- Refinement close to the well - cell of 1m x 1m x 1.67m

- Oil properties from North Sea Field
- Oil rate constant 500 stb/day ; BHP limit of 1000 psia (single phase flow)
- Oil density of 42 API (50.9 lb/ft3 or 0.815 g/cc) ; $\mu = 0.82$ cP, Bo = 1.21 rb/stb, Pb = 980 psia, Pi = 2436 psia @ 1585m (5200 ft)
Flow Simulation Generates Derivative

Cross section showing k distribution (Model 04c5)

Cross section showing the pressure behaviour during the drawdown

Delta P = 137 psia
Well Testing Analysis of generated derivatives

• Transient pressure analysis performed in the drawdown test period
Validation

- Validation of the workflow: transient pressure response is consistent with the geometric average in the case of model 04c and arithmetic average for model 05c.

<table>
<thead>
<tr>
<th>Model 04c</th>
<th>Whole model 04c</th>
<th>Well location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kar (mD)</td>
<td>31</td>
<td>28</td>
</tr>
<tr>
<td>Kgeo (mD)</td>
<td>3</td>
<td>8</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Model 05c</th>
<th>Whole model 05c</th>
<th>Well location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kar (mD)</td>
<td>59</td>
<td>76</td>
</tr>
<tr>
<td>Kgeo (mD)</td>
<td>5.6</td>
<td>10</td>
</tr>
</tbody>
</table>
Variability analysis

- Different permeability ranges distributed in models with the same macroport patch arrangement (POD) present similar pressure response.
- Same distribution of in all 3 layers.

Systematic double porosity, micro-macroporous carbonate geotype curves
Double Matrix Carbonate Conclusions

- The obtained results validate the numerical well test workflow applied in this study.

- The model dimensions and grid size used in this study were suitable to generate simulated pressure data to be analyzed.

- Visualise tortuous flow path to the well

- Dual permeability (Dual porosity) flow model was interpreted for all models.

- No Fractures in the model but we get a faulted/fracced response

- Object modeling good representation of a vuggy carbonate

- Methodology to generate Carbonate Geotype curves

Corbett et al., 2010, Petroleum Geoscience
Double Porosity Fractured Reservoirs

Storativity Ratio (\( \omega \)) and Interporosity flow coefficient (\( \lambda \))

\[
\omega = \frac{(\phi V C_t)_f}{(\phi V C_t)_f + (\phi V C_t)_m}
\]

\[
\lambda = \alpha r_w^2 \frac{k_m}{k}
\]

"\( \omega \) defines the contribution of the fissure system to the total storativity"

"\( \lambda \) defines the ability of the matrix blocks to produce into the fissure system"

Analysis of the Fracture Pressure Response

- $\phi_f=1\%$, $\omega=1.6\times10^{-3}$
- $\phi_f=10\%$, $\omega=1.6\times10^{-2}$
- $\phi_f=100\%$, $\omega=1.4\times10^{-1}$
Fractured Reservoirs

Outcrop-derived Fracture Model

<table>
<thead>
<tr>
<th></th>
<th>K (md)</th>
<th>ω</th>
<th>S</th>
<th>Lambda</th>
</tr>
</thead>
<tbody>
<tr>
<td>E-Frac Set</td>
<td>186</td>
<td>0.51</td>
<td>-4.5</td>
<td>1.1e-06</td>
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<tr>
<td>NE- Frac Set</td>
<td>143</td>
<td>0.50</td>
<td>-5</td>
<td>6.72e-07</td>
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</table>
Matrix Permeability – Vuggy zones

<table>
<thead>
<tr>
<th></th>
<th>K (md)</th>
<th>(\omega)</th>
<th>S</th>
<th>Lambda</th>
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</thead>
<tbody>
<tr>
<td>E-Frac Set</td>
<td>210</td>
<td>0.33</td>
<td>-4.6</td>
<td>1e-06</td>
</tr>
<tr>
<td>NE- Frac Set</td>
<td>183</td>
<td>0.42</td>
<td>-4.9</td>
<td>3.96e-07</td>
</tr>
</tbody>
</table>

NE set greater storativity  
E set has greater matrix productivity
Numerical Well Test Modelling

- Numerical solution provides ability to model fractures and matrix
  - Analyse tortuous flow along different fracture sets
  - Investigate effects of different oil viscosities
- See typical fracture double porosity response – but not triple porosity response
- Difficult to relate WT parameters back to the model and the reservoir description
Fractured Reservoir Well Testing

Core Petrophysical Outcrop → Triple porosity

Restricted interporosity flow condition → Pseudo-steady state dual porosity model

How do we recover separate matrix and fracture descriptions?
Fracture Well Test Analysis

\[ K \times h = 600 \text{mDft} \]

Where \( h = 60 \text{ft} \)

**Which \( K = 10 \text{mD} \)???

---

Quick Match Results

- Dual-porosity (Pseudo steady state)
- Infinitely acting
- Constant compressibility

\[ \begin{align*}
C_s &= 0.0024 \quad \text{bbl/psi} \\
K &= 10 \quad \text{md} \\
k_h &= 600 \quad \text{md.ft} \\
S &= 4 \\
w &= 0.013 \\
L &= 3.600 \times 10^{-6} \\
P_i &= 7161.7664 \quad \text{psia}
\end{align*} \]

Well bore storage effects
Conclusion

- Reservoir Matrix in Carbonate Reservoirs prone to double matrix porosity (WT) behaviour

- Add fractures and carbonate reservoirs tend to triple-porosity system: matrix (micro), vuggy (macro) and fractures with high tortuosity

- Well testing response doesn’t show triple porosity

- Well Testing response is “effective” double porosity

- How do we extract the double matrix and fracture characteristic parameters?

- Role of numerical well test modelling in carbonates crucial to well test interpretation and reservoir characterisation.

- Limitations in the models and/or in the responses?

Corbett et al., 2010, Petroleum Geoscience
Outcrops and Well Testing 1

• San Andres Example
• Permeability characterisation
• Numerical Well test modelling

Image from Charlie Kerans (BEG)
General San Andres information

San Andres Formation
30% oil recovery
Shallow water
OPT=9 billion bbl

Sequence stratigraphy:
1. Depositional sequence
2. High-frequency sequences
3. Cycles

Six rock fabrics dominated by:
1. Intergranular
2. Separate vug
3. Dense intercrystalline pore types

Kerans et al 1994
Simulation workflow

HFS Framework modelling

Property modelling
- Facies
- Porosity and permeability

Development strategy

Kazemi et al. 2011
Some simulation results

### Input data

**Porosity**

- Variogram range 400 ft
- Kz=0.1*Kh

**Permeability**

- Kerans et al 1994

#### Rock types (Por)

<table>
<thead>
<tr>
<th>Rock type</th>
<th>min</th>
<th>max</th>
<th>mean</th>
<th>SD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grainstone</td>
<td>0.06</td>
<td>0.2</td>
<td>0.12</td>
<td>0.06</td>
</tr>
<tr>
<td>Grain dominated packstone</td>
<td>0.06</td>
<td>0.2</td>
<td>0.14</td>
<td>0.07</td>
</tr>
<tr>
<td>Mud dominated packstone</td>
<td>0.04</td>
<td>0.16</td>
<td>0.105</td>
<td>0.05</td>
</tr>
<tr>
<td>Highly moldic grainstone</td>
<td>0.17</td>
<td>0.3</td>
<td>0.23</td>
<td>0.12</td>
</tr>
<tr>
<td>Moldic grainstone</td>
<td>0.07</td>
<td>0.23</td>
<td>0.16</td>
<td>0.08</td>
</tr>
<tr>
<td>Tight mudstone</td>
<td>0.01</td>
<td>0.05</td>
<td>0.02</td>
<td>0.01</td>
</tr>
</tbody>
</table>

#### Rock types (Perm)

<table>
<thead>
<tr>
<th>Rock type</th>
<th>min (mD)</th>
<th>max (mD)</th>
<th>Geomean</th>
<th>SD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grainstone</td>
<td>0.5</td>
<td>700</td>
<td>17</td>
<td>34</td>
</tr>
<tr>
<td>Grain dominated packstone</td>
<td>0.01</td>
<td>8</td>
<td>2.5</td>
<td>5</td>
</tr>
<tr>
<td>Mud dominated packstone</td>
<td>0.01</td>
<td>2</td>
<td>0.4</td>
<td>0.8</td>
</tr>
<tr>
<td>Highly moldic grainstone</td>
<td>0.06</td>
<td>30</td>
<td>2.5</td>
<td>5</td>
</tr>
<tr>
<td>Moldic grainstone</td>
<td>0.01</td>
<td>100</td>
<td>2.2</td>
<td>4.4</td>
</tr>
<tr>
<td>Tight mudstone</td>
<td>0.001</td>
<td>0.1</td>
<td>0.05</td>
<td>0.1</td>
</tr>
</tbody>
</table>
Variogram range, ft

400

100

50

10

4

Porosity

Kerans et al 1994
Kerans et al 1994
Well location effect

Interpretation

<table>
<thead>
<tr>
<th></th>
<th>Well A1</th>
<th>Constant average kh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well A3</td>
<td>Mobility reduction (kh/mo)</td>
<td></td>
</tr>
</tbody>
</table>

Kerans et al 1994
Low perm HFS effect

Kerans et al 1994
Variations with intra-POD correlation length
Model comparison

Numerical WT time scale
LRAT control

After 100 hrs

After 3000 days

Kerans et al 1994
Outcrops and Well Testing 2

Å Coquina limestone reservoirs are important component of Brazil’s Pre-Salt reservoirs.

Å Subsurface heterogeneities and geometries are poorly quantified in Coquina reservoirs.

Å Well test interpretation in carbonates can be ambiguous.

Kerans et al. 1994
Background

Important component of Brazil’s Pre-Salt reservoir.

Subsurface poorly quantified in Coquina reservoirs

Ambiguous well test interpretation in carbonates

“The double porosity behaviour is consistent with the fact that the reservoir is composed of calcites and dolomites where it can be noticed a difference between the contribution of the matrix and fractures”

Warszawski and Fereira, 2013

Libra Field – Coquinas
ANP promotional document

Depositional heterogeneities, Morro de Chaves, Se-Al, Brasil
Conversion of Outcrops to Well Test

Carbonate Samples

Geological Statistics

Reservoir Model

Pressure Transient Analysis

Well Test Analysis


Lipovetsky et al 1994
Outline

Å Background to the outcrop study

Å Numerical (Geological Well Testing)

Å Interpretation Ambiguities

Å Future work
Location Sao Sebastiao (Atol/Cimpur) Quarry

Alagoas State, NE Brazil
Possible Pre-Salt Analogue

Sao Sebastiao Quarry
Morro de Chaves

Access to various layers along benches and roads
Stratigraphic profile – yellow dashed line
Photomicrographs from the Morro do Chaves Fm coquinas showing porosity (in blue). (A) high degree of corrosion porosity, (B) mouldic porosity, (C) low intercrystalline porosity and (D) patchy microporosity.
SACL poroperm data set

<table>
<thead>
<tr>
<th></th>
<th>Porosity (Decimal)</th>
<th>Permeability (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arith Av</td>
<td>0.15</td>
<td>100</td>
</tr>
<tr>
<td>Geom Av</td>
<td>0.14</td>
<td>26</td>
</tr>
<tr>
<td>Harm Av</td>
<td>0.13</td>
<td>0.76</td>
</tr>
<tr>
<td>StDev</td>
<td>0.04</td>
<td>143</td>
</tr>
<tr>
<td>CV</td>
<td>0.28</td>
<td>1.43</td>
</tr>
<tr>
<td>N_samples</td>
<td>48</td>
<td>48</td>
</tr>
<tr>
<td>Tolerance (%)</td>
<td>7.94</td>
<td>41</td>
</tr>
<tr>
<td>N_zero (20% Toler.)</td>
<td>7.57</td>
<td>206</td>
</tr>
<tr>
<td>N_zero (50% Toler.)</td>
<td>1.21</td>
<td>33</td>
</tr>
<tr>
<td>Min</td>
<td>0.05</td>
<td>0.1</td>
</tr>
<tr>
<td>Max</td>
<td>0.21</td>
<td>742</td>
</tr>
</tbody>
</table>

V. Het

Lipovetsky et al 1994
Porosity and Permeability

\[ k = \left( \frac{\phi}{1 - \phi} \right) \]

FZI: Flow Zone Indicator (defines the petrotypes boundaries).

GHU can be shown as FZI values.

Å Challenge in carbonates:

1 value of \( \phi \) - \( n \) values of \( k \)

Lipovetsky et al 1994
The Lorenz Plot

- h vs. kh (h = thickness).
- Obtained from reservoir core samples.
- Points plotted in order of decreasing k/
- Uniform rock properties: points fall on a diagonal: h is a linear function of kh.
- Heterogeneous rock: points are shifted further away from the diagonal.

Lorenz Plot example. Corbett et al., 2005.

Lipovetsky et al 1994
Lenses

- Previous clastic work
- Coarse grain concentration in channel deposits: Great k;
- Vertically and horizontally limited;
- Surrounded by a low k matrix;
- Many lenses can be modelled as one equivalent (Sagawa et al., 2000)

“*In carbonates, the presence of lenses is not so clear, but matrix heterogeneity exists in many forms – including lenses.*” (Corbett, p.c.)

Example of Reservoir with high permeability Lenses. In this case, k means permeability. Sagawa *et al*., 2000.
Entire reservoir parameters are inferred from a few cores;

Averaging methods:

\[ K = \left[ \frac{1}{1} \right] \]

\[ K = \left( \frac{1}{1} \right) \]

\[ K = \frac{1}{1} \]

Alternative estimators for well test permeabilities depend on the geometry of the lenses at the bed-scale. Corbett, 2013.
Geological Statistics

Entire reservoir parameters are inferred from a few cores.

Averaging methods:

\[
K = \left[ \begin{array}{c} 1 \\ \end{array} \right] \\
K = \left( \begin{array}{c} \end{array} \right)'
\]

\[
K = \frac{1}{1}
\]

Alternative estimators for well test permeabilities depend on the geometry of the lenses at the bed-scale. Corbett, 2013.

Lipovetsky et al 1994
Morro de Chaves Plugs Analysis

Morro de Chaves Global Hydraulic Elements: Poroperm distribution (Corbett and Borghi, 2013). If there were a fracture, it would be represented by data in the upper redish-left region (low porosity, high permeability values). The lens data is indicated in the orange band, and corresponds to 33% of the inflow to the well.

Lorenz Plot

Morro de Chaves Lorenz Plot. (Corbett and Borghi, 2013) Box shares 33% of transmissivity (due to only 3 plugs).

Porosity-permeability values (Corbett and Borghi, 2013). The shaded values correspond to the orange band.

Lipovetsky et al 1994
The Modelled Reservoir Scenarios

A Lorenz Plot *average* values:

<table>
<thead>
<tr>
<th>Property</th>
<th>Lens</th>
<th>Reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity (arithmetic average)</td>
<td>18.8%</td>
<td>14.9%</td>
</tr>
<tr>
<td>Permeability (geometric average)</td>
<td>533 mD</td>
<td>21.14 mD</td>
</tr>
<tr>
<td>Transmissivity</td>
<td>33%</td>
<td>67%</td>
</tr>
</tbody>
</table>

Transmissivity, Porosity and Permeability values for Lens and Reservoir, through the assessment of the Lorenz Plot.

Values obtained from the black box in the Lorenz Plot. These will be used to model the lens.

A Outer Matrix:

\[ k \]

Obtained from the *geological statistics* for the outer matrix.

A Near wellbore matrix: \( k \) and will have lower values (10mD and 0.10, respectively).

Lipovetsky et al 1994
The Built Scenarios

Scenario 1

Scenario 2

Scenario 3

Scenario 4

*Initial Reservoir and Fluid Properties: See the final slide.

Lipovetsky et al 1994
The FVM 2-D Multiphase Flow Simulator

- **Black Oil**: recovery processes are intensive to compositional changes in the reservoir fluids.

To simulate how the Scenarios behave, the Hydraulic Diffusivity Equations are incorporated, applied to the FVM and to the IMPES Method.

Schematic figure of radial reservoir, with well placed in the middle (represented in blue).

Lipovetsky et al 1994
Well Test Analysis

Early time affects might be numerical issues, simulation issues or subtleties associated with the partial perforation effect with 'shoulders'

Lipovetsky et al 1994
Well Test Analyses: Comparison and Validation

Three different simulators – broad agreement in the middle time region

Lipovetsky et al. 2014

Whittle, 2014
Flow simulation (Commercial code FDM)

Scenario 1  1h

Scenario 2

Scenario 3

Scenario 4

Homogeneous
Well Testing Conclusions

Response to a single pod intercepted by well
Lipovetsky et al. 2014

Response to multiple pods intercepted by well
Corbett et al., 2010
Fractured or not?

Reservoir Engineering – **YES**
- Well test double porosity response
- Negative skin

Geology – **YES**
- Image Log
Highly fractured cluster about 4 m thick with preferentially-oriented, intersecting fractures and possible little breccia.
Automated Well Test Analysis

\[ k = 13 \text{ mD} \]
\[ \omega = 0.14 \]
\[ \lambda = 1.1 \times 10^{-6} \]
\[ S = -5.4 \]
\[ l = 0.1 \text{ m} \]
\[ k_m = 0.35 \mu\text{D} \]

Well bore storage effects?
Fractured or not?

Å Reservoir Engineering – **YES**
- Well test response
- Negative skin
- Cross-flow

Å Geology – **NO**
- No fractured core
- No open fractures on image logs
- No significant losses
Fractured or not?

Å Reservoir Engineering – **YES >>> NO**
- Well test response
- Negative skin >> not fractures >> double matrix
- Cross-flow >> not fractures >> double matrix

Å Geology – **NO**
- No fractured core
- No open fractures on image logs
- No significant losses
Acknowledgements

Total Professorship (1994-2012)
BG Group Professorship (2012-2017)

Colleagues
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International Centre for Carbonate Reservoirs
Schlumberger (Eclipse) Weatherford (PanSystem)
Fractured Reservoir Myths

- Fractures mostly have a high angle origin – but only to bedding (Lewis, HWU)
- Is use of curvature good – OK for thinly bedded systems (Couples, HWU)
- Is fracture porosity always low (1-2%) – yes generally but not always (Quenes, Sigma³)
- Is the fractal model a good one – there are length scales, layering and the mechanical stratigraphy is important (Couples, HWU; Riva GE Plan),
- Mechanical fractures follow existing fracture patterns (Alverellos, Repsol)
- Thermal Fracturing in low permeability rocks – also high permeability sandstones (Tovar, IES)
- Continuum fracture models vs Discrete Fracture models – upscaling DFN is very challenging (Geiger, HWU)
- There is no REV in fractured reservoirs – except possibly at the seismic bin scale (Quenes, Sigma³) and at the bed scale (Couples, HWU; Riva GEPlan)
- Basement provide seals and migration barriers – but not if fractured (Hartz, Det Norske Oljeselskap)
- Ruger equation can give fracture orientation and density – simple laboratory models show this equation sometimes holds (Chapman, Edinburgh University)

Source: EAGE-SBGf Fracture workshop – Rio Nov 2013
Fracture Reservoir Agreement

- Fractures are difficult to locate but easy to predict with the correct structural model (Lewis, HWU)
- Fracture Models should be driven by data and concepts (Riva, GE Plan)
- Fractures develop though complex history of burial and many stress episodes (Bezerra, UFRN; Betotti (TUDelft))
- Lithology and facies have an impact on fracture distributions (Cazarin, Petrobras)
- Need to model fractures in 3D (Hartz, Det Norske Oljeselskap; Moos, Baker-Hugues)
- A multidisciplinary approach to tackle fractures is necessary

Source: EAGE-SBGf Fracture workshop – Rio Nov 2013
New Myths

• “v” shaped response >> not always fractures
• “vv” response >> not common
• Infinite/Finite conductivity fracture (before fraccing) >> Double Matrix X-Flow
• Triple porosity >> Difficult to detect in Well Test
• Matrix reservoirs with strong contrasts (carbonates) can flow like fractured reservoirs
• Geologist must engage more effectively with well testing community and vice versa
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Patrick Corbett’s AAPG tour
May/June 2014

- Flight
- Train

- 12th – 16th May
- 19th – 21st May
- 30th May – 6th June