Using reservoir mixing to evaluate reservoir compartmentalization from appraisal data – validation using data from the Horn Mountain field, Gulf of Mexico

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Overview: Reservoir compartmentalization

- segregation of the reservoir into segments that behave as separate flow units
- caused by barriers or baffles to fluid flow
Overview

• Horn Mountain overview
• Previous work done on Horn Mountain compartmentalization
• New workflow to assess reservoir compartmentalization
• Results
• Validation
• Conclusion
Horn Mountain oil field

- Discovered in 1999 by Vastar, currently 100% BP owned

- Middle Miocene Reservoirs
  - **J Sand** (~12,200’ TVDSS)
  - **M Sand** (~14,200’ TVDSS)

- Faults appear to separate both reservoirs into northern, central and eastern fault block (**NFB, CFB and EFB**)

Milkov et al (2007)

- Time-lapse geochemistry (TLG)
  - oil fingerprints from production samples are analyzed and compared with preproduction fluids

- Compartmentalization risk matrix (CRM)
  - risk of flow barriers between wells are assigned for each data set (e.g., pressure, geochemical data)
  - Traffic light indicators (low risk = green, high risk = red)
Limitations/gaps in present methods: TLG

- Production samples are needed!
- Not feasible for commingled wells

Different oil fingerprints!

Fault permeability, $k = ???$

Time-lapse geochemistry

Barrier?
Limitations/gaps in present methods: CRM

Compartmentalization risk matrix
- Qualitative
- Large uncertainty in conclusions remain
Alternative method: Appraisal data + Reservoir mixing

Fault permeability, \( k = 0.01 \text{ mD} \)

Pressure dissipation model

\[
\frac{k}{\mu} \frac{\partial^2 P}{\partial z^2} = \phi c^e \frac{\partial P}{\partial t}
\]
Workflow to evaluate reservoir compartmentalization

1. Appraisal data
   - Core/Seismic
     - Wells/Well pairings
   - SCAL
     - Reservoir properties
   - Pressure
     - Pressure shift
   - PVT
     - Density contrast

2. Mixing processes
   - Molecular diffusion
   - Pressure dissipation
   - Gravitational overturning

3. Mixing time-scales
   - Mixing time-scales < Perturbation time
   - variation holds for the predicted MIXING PERMEABILITY /LENGTH
   - Barrier, Baffle or none
Appraisal data: seismic – lateral compartmentalization

- Geological faults from seismic data
- Is it sealing or transmitting?
- Well pairings are chosen to assess lateral reservoir connectivity

![Diagram with geological faults and well locations]
Appraisal data: MDT and PVT

- Excess pressure plots by Brown, 2003 provides better pressure shift interpretation

\[ \Delta \rho = 15 \text{ kg/m}^3 \]

Molecular diffusion

Mixing time > perturbation time (15 My)
Composition is not diagnostic - Fluid is still mixing!

Well pairing | Seismic | Pressure | PVT | Geochemistry | Risk | time-scale, My
--- | --- | --- | --- | --- | --- | ---
#1ST1 - #1ST2 | | | | | | 19
#1ST1 - #3 | | | | | | 19
#2ST1 - #2ST3 | | | | | | 44
#2ST1 - #3 | | | | | | 24
To maintain present variations in pressure, reservoir permeability should be at least 1 mD – existence of barriers!

Pressure dissipation – no barrier \((t = 15 \text{ My})\)

NOTE: Pressure shift is below the 2psi accuracy threshold

\[ k = 1.2 \text{ mD} \]

\[ k_{\text{actual}} = 916 \text{ mD} \]

<table>
<thead>
<tr>
<th>Well pairing</th>
<th>Seismic</th>
<th>Pressure*</th>
<th>PVT</th>
<th>Geochemistry</th>
<th>Risk</th>
<th>Mixing permeability, mD</th>
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<td></td>
<td></td>
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*pressure difference (psi) between wells.
To maintain present variations in pressure, fault permeability should be at least 0.01 mD – existence of barriers!

Pressure dissipation – continuous fault ($t = 15$ My)

$k = 0.01$ mD

Leaky edges

Observation well

Seal (zero permeability)

$L$

Seal (zero permeability)

*pressure difference (psi) between wells.*
To maintain present variations in density, reservoir permeability should be at least 170 nD – existence of barriers!

Gravitational overturning ($t = 15$ My)

$k = 170$ nD

<table>
<thead>
<tr>
<th>Well pairing</th>
<th>Seismic</th>
<th>Pressure</th>
<th>PVT*</th>
<th>Geochemistry</th>
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*density contrast ($\text{kg/m}^3$) between wells.
Appraisal data + Reservoir mixing in Reservoir J

Pressure dissipation – continuous fault \((t = 15 \text{ My})\)

\[ k = 0.08 \text{ mD} \]

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*pressure difference (psi) between wells.
How extensive are these shale barrier?
**Vertical compartmentalization - #2**

- **Pressure shift ~ 4psi**
- **Reservoir thickness = 10 m**
- **Shale thickness = 100 m**
- **Shale length, L ~ 2km**
- **Shale permeability, k ~ 16 mD**

*Graph showing pressure dissipation around a shale layer.*

*Graph showing mixing time (years) vs. shale length (m).*

*Legend:*
- Pressure dissipation
- Reservoir thickness
- Shale thickness
- Shale length
- Shale permeability
- Pressure shift

*Map showing fault lines, water injectors, and appraisal wells.*

*Annotations on map:*
- Reservoir M
- MC 126
- Shale-filled channel
- Faults
- Producers
- NKB
- 125.000
- 13,000
- 14,000
- 15,000
- 16,000
- 17,000
- 18,000
Validation: production data

- Inter-well connectivity are reflected by the correlation rates between injectors and produces using Spearman rank correlation

- Soeriawinata-Kelkar method
  - Choose producer and adjacent injector with highest correlation (>0.25)
  - Find injector that produces highest significant cross correlation improvement (>0.5)
  - Find injector that has high cumulative cross correlation increment (>0.01)

- Applied to Reservoir M only – Reservoir J has no injectors

Validation: production data

<table>
<thead>
<tr>
<th>Producer</th>
<th>Injectors</th>
<th>Cross correlation</th>
<th>Initial assessment</th>
<th>Cumulative cross correlation</th>
<th>Inference</th>
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<td>A7</td>
<td>0.08</td>
<td>poor</td>
<td>0.28</td>
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</table>
Validation: production data

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<tr>
<td>A1</td>
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<td>0.55</td>
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</table>
Milkov’s TLG vs. Spearman rank correlation vs. Reservoir mixing

Fault permeability \( k = 0.02 \) mD

Flow barrier separating NFB and CFB
TLG: No oil arrived from the NFB to the existing producing well A10 (CFB) across the fault separating NFB and CFB

1. there is a flow barrier separating NFB and CFB

2. drill another producer in the NFB or recomplete appraisal wells penetrating this fault block

Fault permeability \( k = 0.08 \text{ mD} \)
Conclusions

• Reservoir compartmentalization can be identified at an early stage using the devised new workflow even without production data.

• Barrier/baffle properties (e.g., Fault permeabilities or shale lengths) can be estimated using reservoir mixing rates.

• Faults identified within the Horn Mountain field are relatively impermeable and serve as barriers for oil migration as confirmed not only by using TLG and inter-well connectivity but also by using analytical expressions to estimate fluid mixing time-scales.
Acknowledgements

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