PS Characterizing Compartmentalization in Structurally Heterogeneous Reservoirs Using Fluid Mixing Time-Scales*

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Search and Discovery Article #41423 (2014)**
Posted August 25, 2014

*Adapted from poster presentation at AAPG Annual Convention and Exhibition, Houston, Texas, April 6-9, 2014

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Abstract

Detection and characterization of reservoir compartmentalization during appraisal is significantly improved by using fluid data (pressure, contacts, density and composition) and the rate at which these observed fluid variations equilibrate over geological time-scales. This essentially involves comparison of the time-scales for any observed fluid property variation(s) to homogenize with the time since the reservoir filled. A suite of published analytical expressions for fluid mixing via molecular diffusion, gravitational overturning, or pressure diffusion have been used previously to quantify mixing time-scales. These have subsequently been applied to field studies to identify and quantify barriers and baffles to flow. These analytical mixing relations, however, have been derived for idealized reservoir geometries (e.g., 1D and 2D box models), where the fluid mixing time-scales are simply estimated over straight line distances between two observed points (e.g., wells). In reality, most reservoirs are structurally heterogeneous (e.g., with folding, anticlines, faulting), and thus mixing times may be increased due to the non-linear mixing distances within the reservoir. It is not clear whether such analytical estimates of mixing time are reliable in these cases. In this study, we investigate the time taken for fluid contacts and fluid densities in a faulted anticlinal reservoir to reach equilibrium, using detailed numerical simulation, compared with existing analytical solutions for a box reservoir. We present an easy method for estimating an effective mixing distance and thus the mixing time in such cases without recourse to simulation. A simple field case study from a giant Middle Eastern oil field is presented demonstrating these principles. This confirms previous work that observed fluid contact variations in the field do not necessarily indicate the presence of barriers to flow. Using the effective mixing distance of ~100 km, the estimated mixing time is long (~1My) compared to the time since the reservoir filled or aquifer started flowing, and thus the overturning of fluid contacts in the field has not yet reached steady state.

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CHARACTERIZING COMPARTMENTALIZATION IN STRUCTURALLY HETEROGENEOUS RESERVOIRS USING FLUID MIXING TIME-SCALES

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ABSTRACT. Detection and characterization of reservoir compartmentalization during appraisal is significantly improved by using fluid data (pressure, contacts, density and composition) and the rate at which these observed fluid variations equilibrate over geological time-scales. This essentially involves comparison of the time-scales for any observed fluid property variation(s) to homogenize with the time since the reservoir filled. A suite of published analytical expressions for fluid mixing via molecular diffusion, gravitational overturning or pressure diffusion have been used previously to quantify mixing time-scales. These have subsequently been applied to field studies to identify and quantify barriers and baffles to flow.

These analytical mixing relations however have been derived for idealized reservoir geometries (e.g. 1D and 2D box models) where the fluid mixing time-scales are simply estimated over straight line distances between two observed points (e.g. wells). In reality, most reservoirs are structurally heterogeneous (e.g. with folding, anticlines, faulting) and thus mixing times may be increased due to the non-linear mixing distances within the reservoir. It is not clear whether such analytical estimates of mixing time are reliable in these cases.

In this study, we investigate the time taken for fluid contacts and fluid densities in a faulted anticlinal reservoir to reach equilibrium using detailed numerical simulation, compared with existing analytical solutions for a box reservoir. We present an easy method for estimating an effective mixing distance and thus the mixing time in such cases without recourse to simulation. A simple field case study from a giant Middle Eastern oil field is presented demonstrating these principles. This confirms previous work that observed fluid contact variations in the field do not necessarily indicate the presence of barriers to flow. Using the effective mixing distance of ~100 km, the estimated mixing time is long (~1My) compared to the time since the reservoir filled or aquifer started flowing and thus the overturning of fluid contacts in the field has not yet reached steady state.

1. What is reservoir compartmentalization?

- A reservoir is **compartmentalized** if **fluids do not flow freely** from one part of the field to another over **production time-scales**[6].
- Reservoirs may be compartmentalized by:
  - Continuous shale layers
  - Sealing faults
  - Diagenetic changes

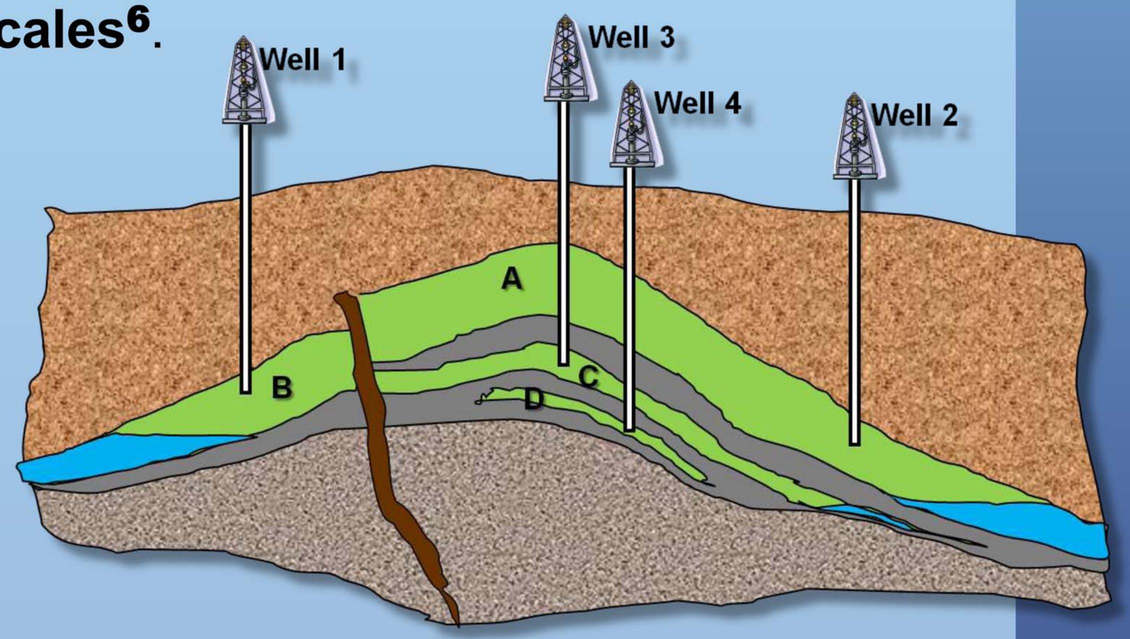


Figure 1. Cartoon of a compartmentalized field

- Compartmentalization is a key uncertainty at appraisal
  - ✓ Controls amount and spatial distribution of reserves – impacts development of surface facilities.
  - ✓ Affects the number of wells needed for oil recovery – complex field means more wells, less profit.

Unidentified compartmentalization may turn a commercial development into an uneconomic one.

2. How is compartmentalization identified?

Static vs dynamic data

- Faults can be observed from 3D seismic data

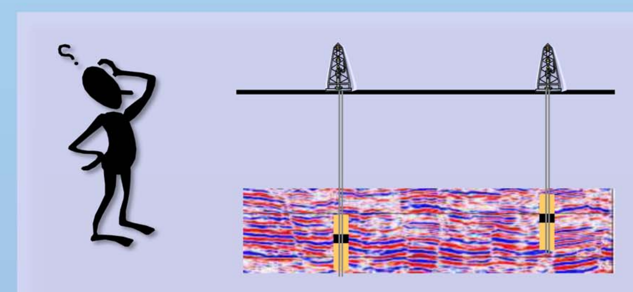
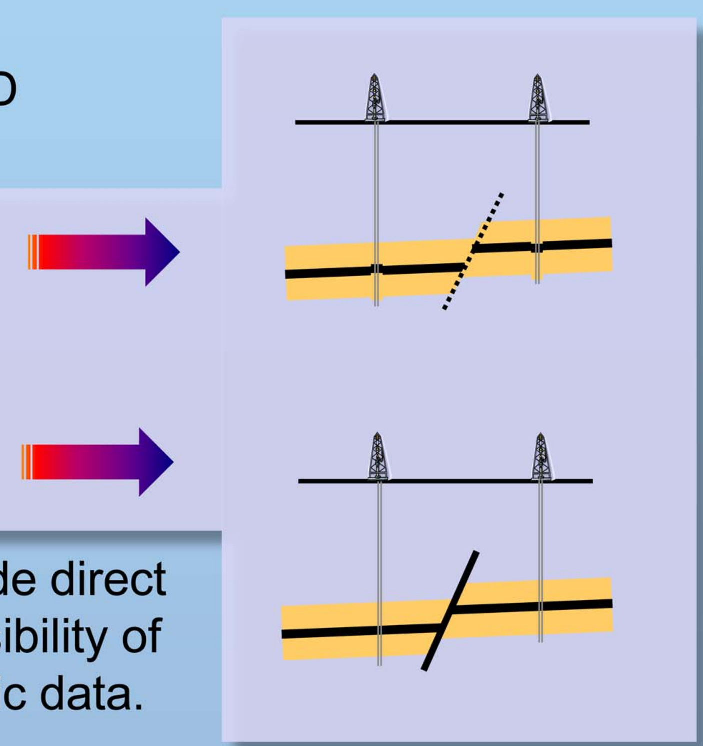


Figure 2a. Seismic line showing two wells



- **BUT,** seismic data do not provide direct information about the transmissibility of faults until calibrated by dynamic data.

- Well logs can show if there are low permeability shale layers in the field

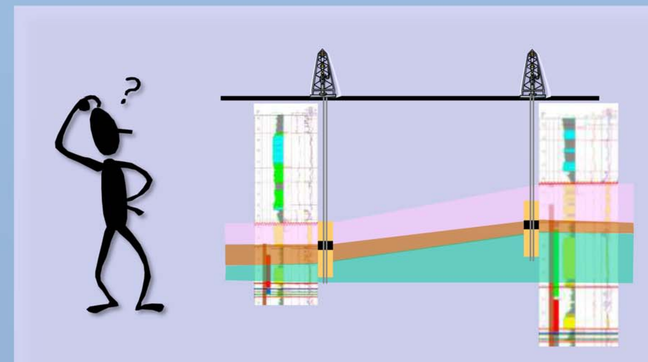
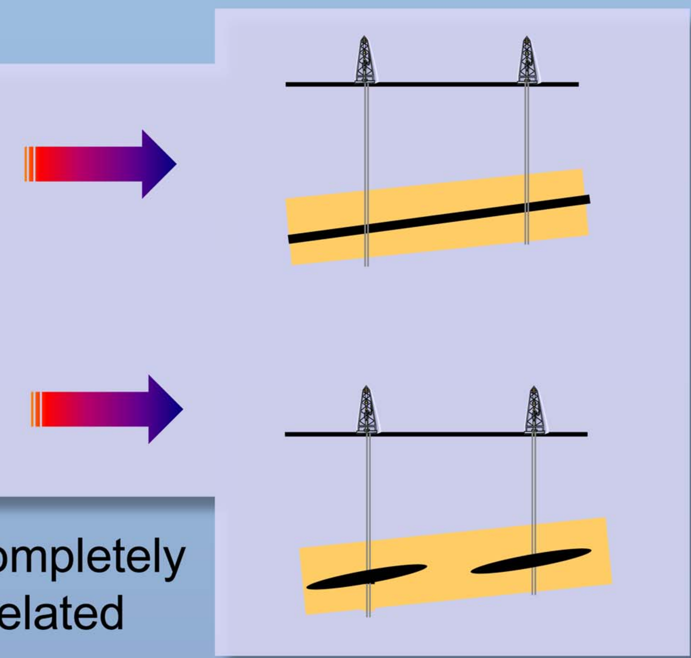


Figure 2b. Well log data showing potentially correlated shale layer



- **BUT,** shale layers may not be completely continuous even if it can be correlated across several appraisal wells.

3. Mixing time-scales to detect compartmentalization

SIMPLE VIEW: There is a barrier to flow if different **contact depths**, **pressures**, **fluid properties** (e.g. density, GOR), **fluid composition** or combinations of these are observed at different locations in the field.

BUT, reservoir fluid properties may not be in equilibrium because there has been insufficient time for them to mix.

- **Pressure**[4,7] variations take the least time to equilibrate.

$$t_{equil} \sim -\frac{1}{2}\frac{\mu\phi c_e L H_b}{k_b}\ln\left(\frac{\delta P}{\Delta P}\right)$$

	μ (Pa s ×10³)	ρ (kg m⁻³)	c_e (Pa⁻¹)	t_{equil} (no barrier)
Water	1	1000	7×10^{-10}	8 days
Heavy oil	20	850	8×10^{-9}	1,800 days
Light oil	0.9	700	2.5×10^{-8}	260 days
Gas	0.05	200	2.5×10^{-7}	160 days

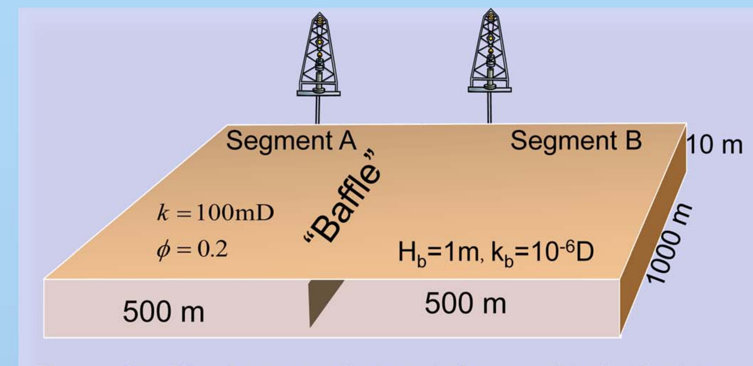


Figure 3a. Simple reservoir description used in fluid mixing.

- **Gravitational overturning**[1,2] is slower than pressure equilibration

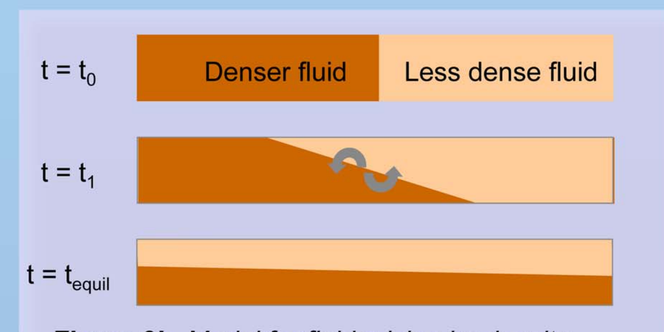


Figure 3b. Model for fluid mixing by density-driven overturning.

$$t_{equil} \sim \frac{25}{4}\frac{L^2\mu\phi}{kgH\Delta\rho}$$

Ex. Oil - Water – 1,2000 y
Heavy oil - Water – 540,000 y
Gas - Water – 2,500 y

- Mixing of hydrocarbon components or pore water constituents by **molecular diffusion**[1,7] takes the longest to equilibrate

$$t_{equil} \sim \frac{L^2}{D\tau}$$

Ex. $L = 10\ m$ – 6,000 y
$L = 1000\ m$ – 60,000,000 y

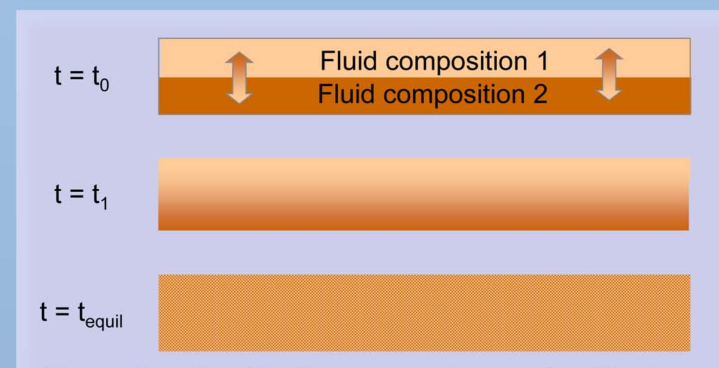


Figure 3c. Model for 2-component mixing by diffusion

THUS, observations of spatially varying fluid properties may indicate compartmentalization if they have existed for longer than the time needed for them to equilibrate[3]**.**

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4. Mixing in structurally heterogeneous reservoirs

- Most reservoirs are structurally heterogeneous (e.g. with folding, anticlines, faulting).
- Effective mixing distance (L_{eff}) within the reservoir is increased to more than simply the horizontal distance (L) between two observation points (e.g. wells).

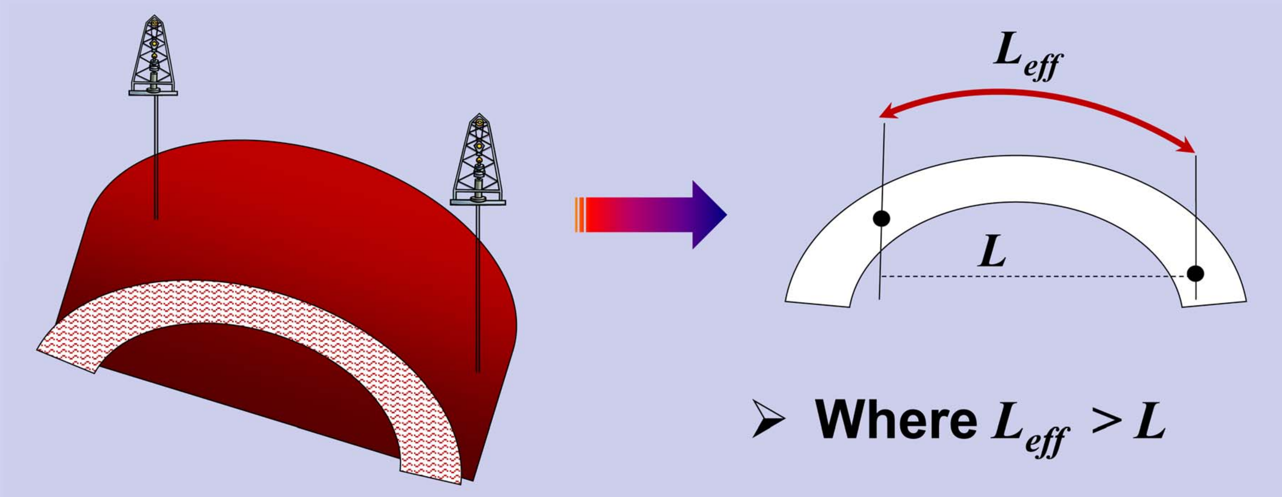

Figure 4a. Effective mixing distance between two wells in an anticlinal reservoir.

- Existing analytical equations for fluid mixing were derived for idealized reservoir geometries (e.g. 1D and 2D box models) and therefore only provide **order of magnitude estimates of mixing times**.

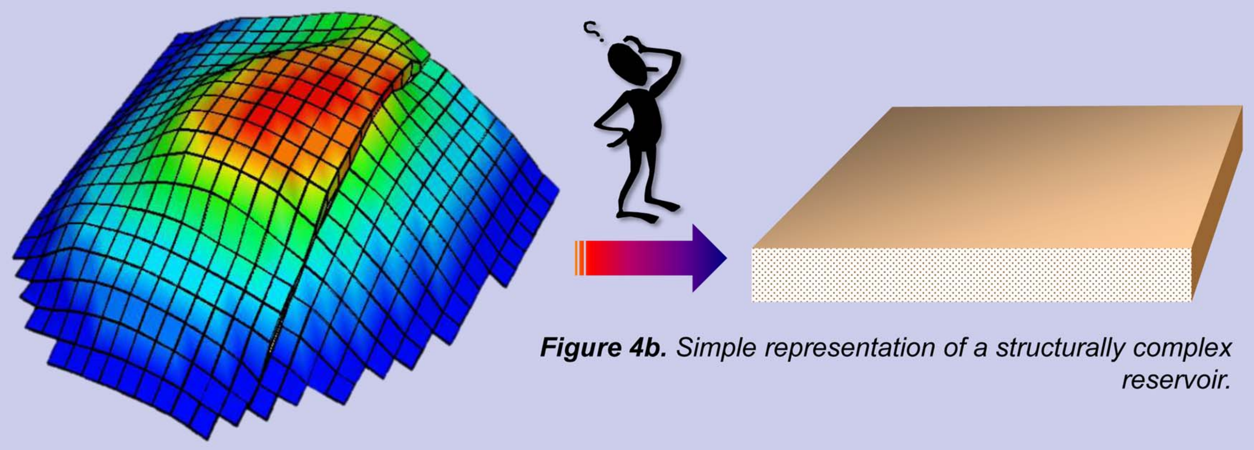

Figure 4b. Simple representation of a structurally complex reservoir.

Are these simple analytical estimates of fluid mixing time still applicable to structurally heterogeneous reservoirs?

5. Numerical simulation of fluid mixing

1. 3D model building with STARS

Using a N-S fault, the 3D reservoir model was divided into 2 sectors which were initialized using different oil mole fractions. This created an oil density difference of 322 kg m^{-3} between the two sectors.

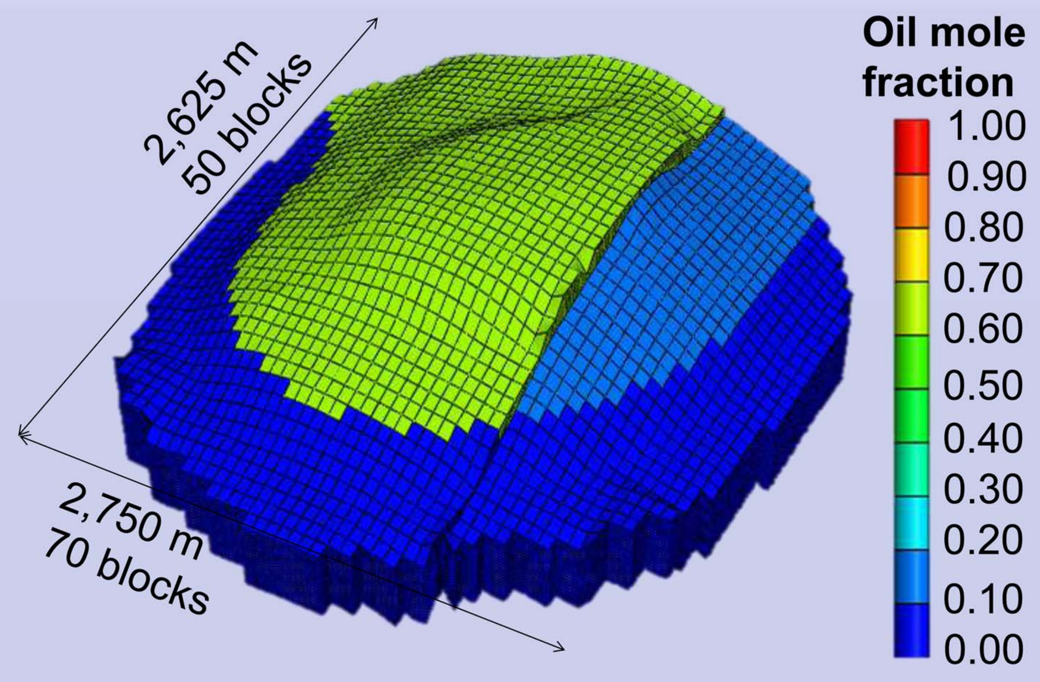

Figure 5a. 3D view of anticlinal reservoir in STARS. Vertical relief is 177m consisting of 20 blocks.

2. Parameterization

Parameters	Values
Porosity	0.20
Permeability (mD)	500
Oil viscosity (Pa s)	0.12
Water viscosity (Pa s)	0.001
Contact height difference (m)	30
Oil density difference (kg m^{-3})	322

3. Gravitational overturning with STARS

The aquifer was modelled by adding boundary cells that contain only water. Different oil-water contact was set for the 2 sectors. The contact height difference between the two sectors was 30 m. The model was then simulated to "relax" back into equilibrium.

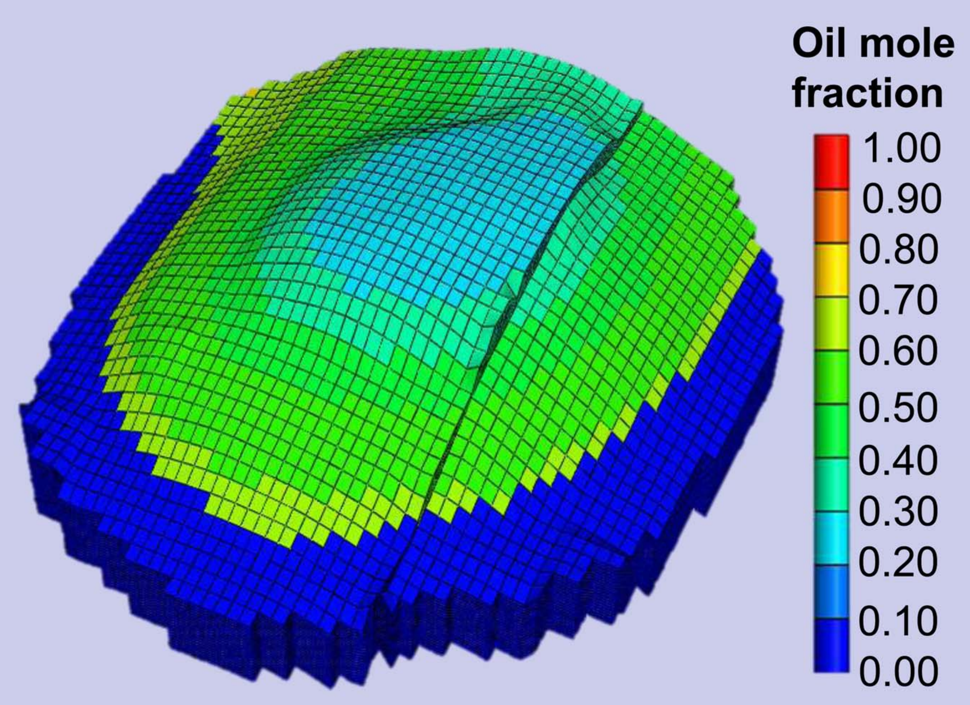

Figure 5b. 3D view of oil mole fraction distribution after 3 My in STARS.

6. Simulation results

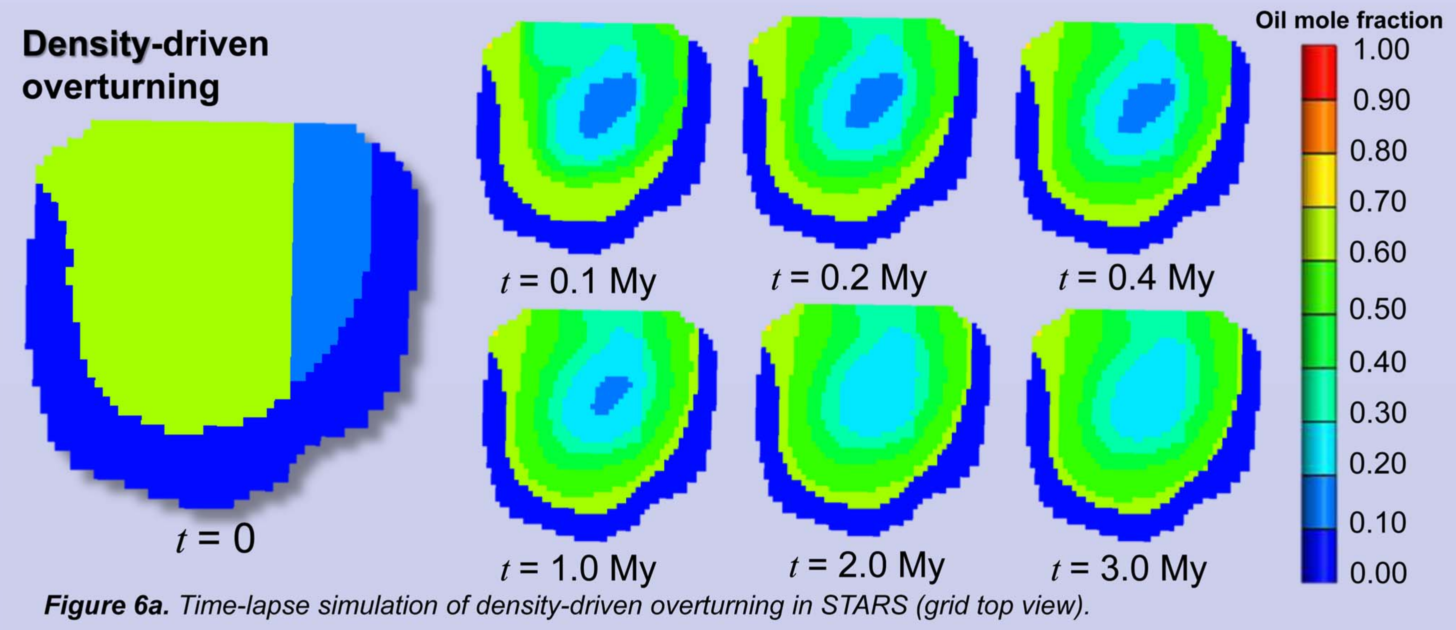

Figure 6a. Time-lapse simulation of density-driven overturning in STARS (grid top view).

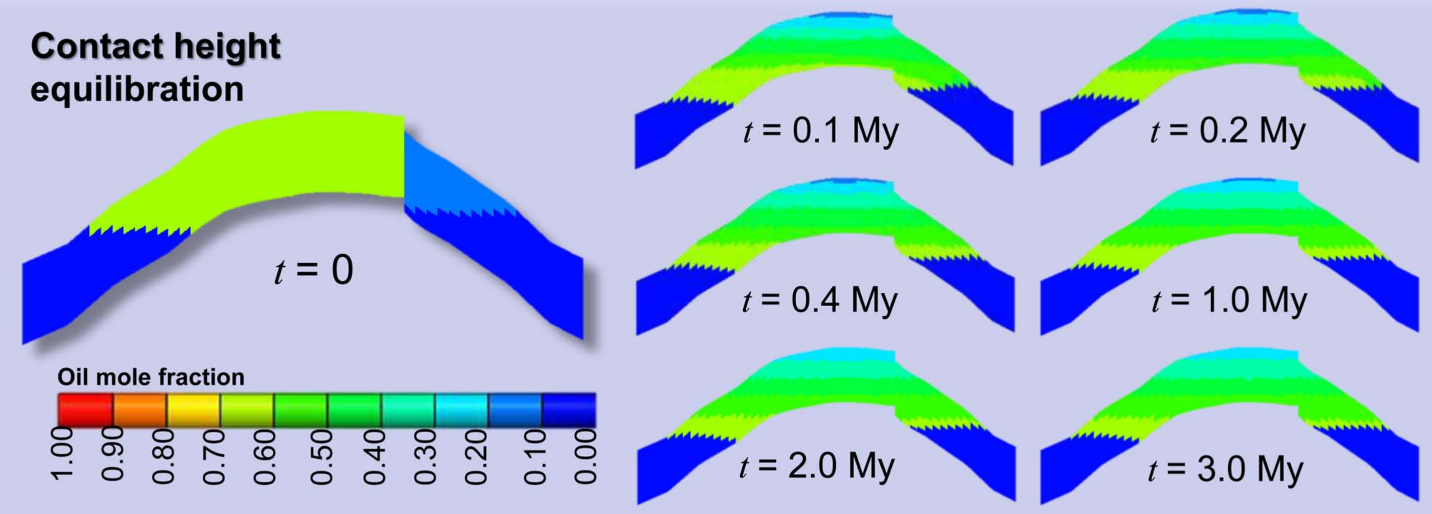

Figure 6b. Time-lapse simulation of fluid contact equilibration in STARS (J layer 43).

- Time taken for the initial fluid contact difference (30m) to equilibrate using the gravitational overturning equation[1,2] compares reasonably well with those predicted by the numerical simulations.
- However, numerical simulations took 3 – 9 hours while the **analytical approach was almost instantaneous.**

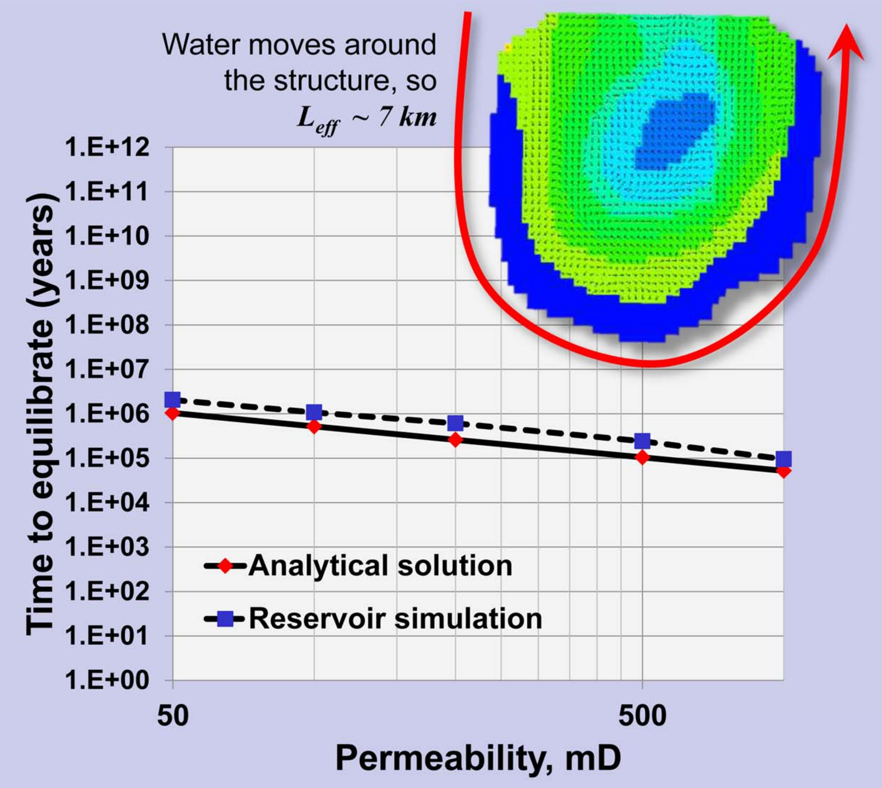

Figure 6c. (Top right) Flow vector diagram depicting direction of flow in the 3D model which was used to evaluate L_{eff}. (Right graph) Comparison of time for overturning of fluid contacts to reach steady state as predicted by analytical solution and numerical simulation in STARS running on 2.53GHz Intel Core 2 Duo CPU and 5 GB of RAM under Windows 7.

THUS, existing analytical solutions can still be used to estimate time-scales for fluid mixing in structurally heterogeneous reservoirs.

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7. CASE STUDY: Giant Middle Eastern oil field

- To demonstrate these principles, we evaluated compartmentalization in a giant Middle Eastern oil field.
- This oil field is a high amplitude, periclinal anticline aligned northwest to southeast consisting of multiple stacked Pliocene reservoirs.
- We focused on a particular reservoir unit that is approximately 27km in length, 5km in width, 40-60 m thick, has high net-to-gross, excellent porosity (20-28%) and permeability (0.1 – 1D) and good lateral pressure connectivity.

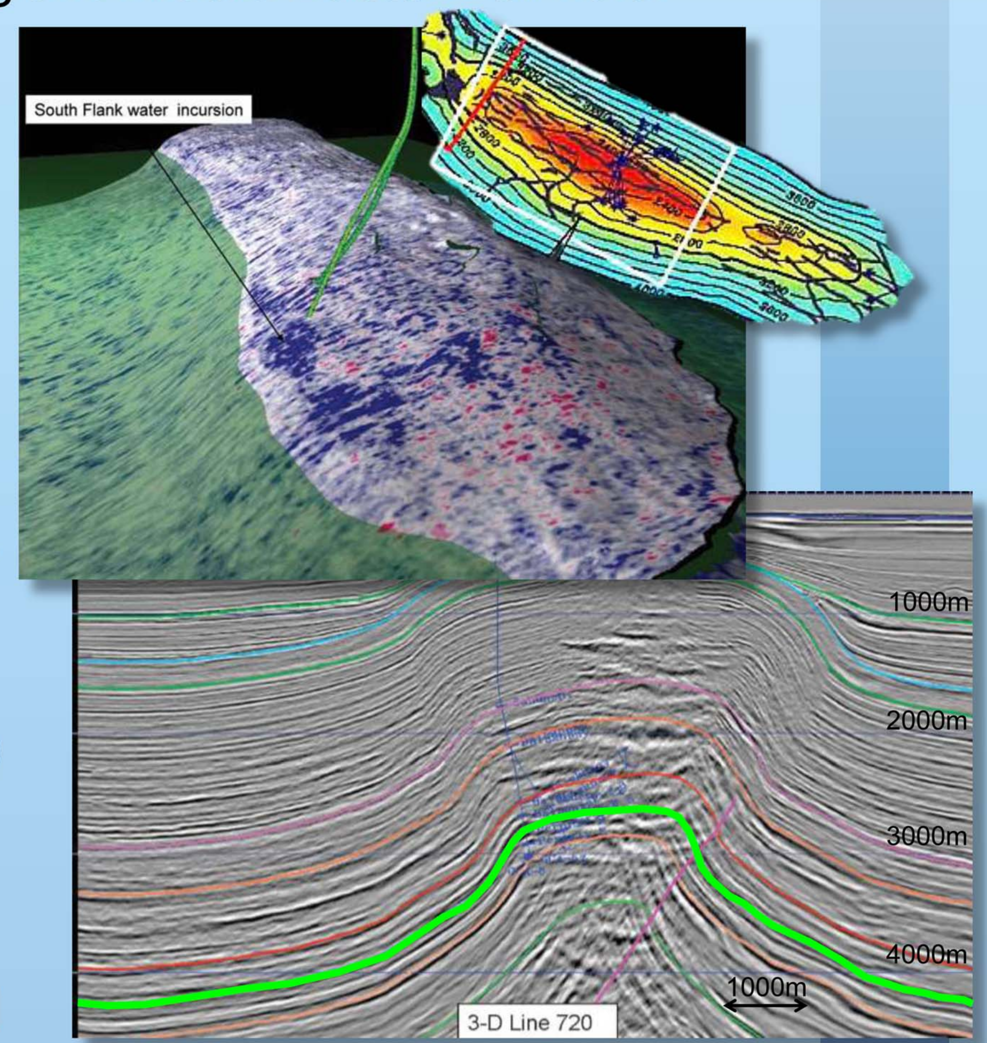

Figure 7a. *1D, 3D and seismic line (thick green line) of the oil reservoir unit* [5, 8].

- At appraisal, oil-water contact on the north flank of the structure was deeper (at 3406 m TVDSCS (metres true vertical depth sub Caspian Sea)) than on the south flank (at 3076 m TVDSCS).

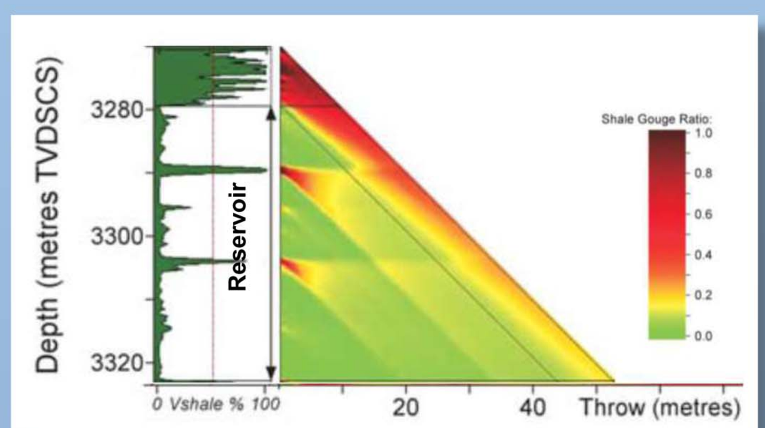

Figure 7b. *Fault juxtaposition diagram generated using Vshale log* [8].

- Well log and seismic data however show that the reservoir is not offset by any fault that has sealing potential (i.e. shale gouge ratio[8] must be >0.2).

Are these observed fluid contact variations in the oil field indicative of compartmentalization?

8. Sealing faults or hydrodynamic aquifer?

- Water moves around the structure, so L_{eff} ~ 100 km

$$L_{eff} \sim \frac{\pi}{2}\sqrt{2\left(a^2+b^2\right)}$$

Where a is the major axis of the ellipse and b is the minor axis

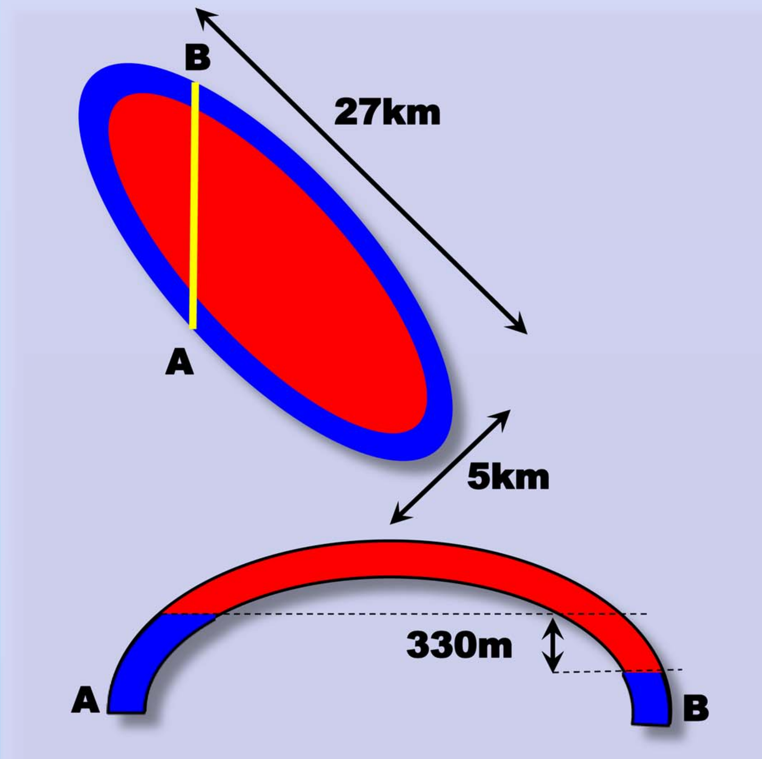

Figure 8a. *Areal cross-section (top) and vertical section through line AB of the reservoir. Red is oil and blue is water.*

- Using the gravitational overturning equation,[1,2] the estimated time taken for the initial oil-water contact (OWC) difference (330m) between the north and south flank of the reservoir to equilibrate is 1.2My.
- If the reservoir was filled (or aquifer started flowing) ~1Ma, **overturning of fluid contacts in the field has NOT yet reached steady state.**

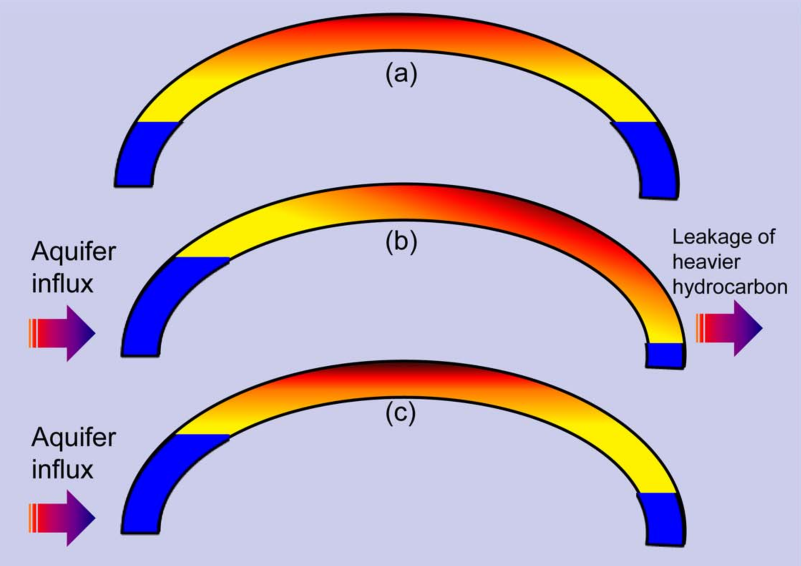

Figure 8b. *Cartoon showing variation of oil-water contacts in the field potentially due to aquifer influx. (a) No aquifer influx, lighter hydrocarbon has risen to the top. (b) Aquifer influx displaces gas cap from left to right resulting in spilling of heavier compounds downstream. (c) Redistribution of lighter components at top of structure but there are now heavier components on right hand side.*

- With aquifer influx, a 330m OWC difference corresponds to a pressure differential at the same depth

$$\Delta P = \rho_w g z = 3.2x10^6\,\text{Pa}$$

- The Darcy velocity of water necessary to support this ΔP

$$v = \frac{k\Delta P}{\mu_w L_{eff}} \approx 45\,\frac{\text{cm}}{\text{year}}$$

THEREFORE, the observed fluid contact variations in the field do not necessarily indicate presence of barriers to flow.

9. Conclusions

- Reservoir compartmentalization can be identified using static (3D seismic, well log) and dynamic data (pressure, fluid contact, density and composition) at appraisal.
- Using existing analytical solutions to estimate mixing time-scales of observed fluid property variations, barriers or baffles to flow in reservoirs can be identified and constrained (e.g. length of shale layers, permeability of faults).
- Existing analytical solutions can still be used to estimate fluid mixing time-scales in structurally heterogeneous reservoirs, provided mixing length is corrected to account for non-linear mixing distances .
- Observed fluid contact variations in the reservoir unit of a giant Middle Eastern oil field do not necessarily indicate presence of sealing faults since overturning of fluid contacts in the field has unlikely reached steady state yet. This result is consistent with previous work done on this field.

ACKNOWLEDGEMENTS. We thank BP for supporting the development of these mixing models and for permission to publish this work.

NOMENCLATURE. D molecular diffusion coefficient, m^2 s^{-1}; g acceleration due to gravity, m s^{-2}; h contact height difference, m; H reservoir thickness, H_b, m; barrier thickness, m; L length of reservoir, m; L_{eff} effective mixing length, m; k reservoir rock permeability, m^2; k_b barrier permeability, m^2; ϕ porosity; $\Delta\rho$ horizontal fluid density contrast, kg m^{-3}; ρ hydrocarbon density, kg m^{-3}; ρ_w water density, kg m^{-3}; δP pressure difference criterion, Pa; ΔP pressure difference, Pa; τ tortuosity; t_{equil} fluid mixing time, year; μ viscosity, cP; μ_w water viscosity, cP; v Darcy velocity, cm year^{-1}; z reservoir depth, m

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