Reservoir simulation of charge history over geologic time matches many measurements of connectivity in stacked turbidite reservoirs

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Summary

Present-day distributions of reservoir fluid properties result from mixing of gas and oil charges, over geologic time. Fluid mixing outcomes are highly variable, covering the whole range of reservoir realizations from simple equilibrated to complex disequilibrium distributions. Fluid dynamic processes lead to current reservoir realizations and are affected by structural flow barriers or depositional stratigraphic barriers such as shale breaks. By understanding hydraulic connectivity implications on oil chemistry, we provide an effective method for the assessment of reservoir connectivity.

We introduce a new way of modeling the implications of hydraulic connectivity on reservoir fluid geodynamic processes leading to present-day reservoir realizations. Reservoir simulations over geologic time are used to match complex fluid charges into the reservoir and we compare these results to many measurements of compositional distribution of reservoir fluids as a new way to test the geologic model of the reservoir. Understanding fluid dynamic and mixing processes leads to a reliable assessment of reservoir structures and connectivity profiles.

Introduction

Separate oil and gas charges occur in many hydrocarbon reservoirs, leading to various reservoir-fluid realizations. The mixing processes of gas and oil are largely dependent on specific attributes of reservoir charging. Chemical evaluation of reservoir fluids can be utilized to establish the present-day outcome of oil and gas mixing over geologic time (Mullins et al., 2023). Methane carbon isotope ($\delta^{13}C$) analysis is used to differentiate hydrocarbon charges, especially in case of the common charge of biogenic gas and oil into reservoirs. Contrary to conventional expectations, reservoir understanding of many reservoirs coupled with fluid chemical evaluation shows that biogenic gas can arrive after oil into reservoirs.

Hydraulic connectivity is a key and necessary condition for drainage in reservoirs where fluids flow through connected rock formations that are either sufficiently permeable or fractured (Mohamed 2019; Mohamed and Mehana 2020). However, reservoirs are often compartmentalized due to the presence of flow barriers resulting from geodynamic processes (Mohamed et al., 2022). Reservoir fluid geodynamics (RFG) occur concurrently with structural geodynamics, defining fluid systems which respond to their evolving reservoir container. Thus, connectivity profiles directly affect the distribution of fluid properties.

By analyzing chemical and geochemical measurements of reservoir fluids, we investigate the current state of thermodynamic equilibration and fluid mixing in young reservoirs. We analyze a reservoir consisting of two stacked turbidite sandstones with an intervening hemipelagic shale which was partially scoured in the upper turbidite deposition. The stacked sandstones are poorly communicated through scour-induced hydraulic connectivity. Primary biogenic gas and oil are distinguished by geochemical measurements. Via reservoir modeling and numerical simulation of the mixing processes, we explore connectivity evaluations and how to delineate connectivity variations with wireline logging measurements such as formation testing measurements that have several applications (Mohamed et al., 2022, 2023). A point gas charge into oil reservoirs could lead to either excellent mixing or gross disequilibrium gradients depending on several factors such as reservoir geometries. We establish parametric conditions that control the fluid mixing outcome, involving the roles of compositional diffusion and momentum diffusion both in simulation and overall fluid mechanics analysis. Different fluid distributions are predicted where reservoir simulation was constrained by narrowing down the outcome of mixing processes using thermodynamic and geochemical evaluation of reservoir fluids.

Theory and Method

The studied reservoir is located in the deepwater Gulf of Mexico (Fig. 1, Xu et al., 2020). Figures 1 and 2 show fluid measurements and well logs for the central fairway wells (T1 and T1ST) and the downthrown block well (T2) while the central fairway wells are the focus of this study (Chen et al., 2018; Mullins, 2019). Asphaltene gradients of both upper and lower sandstones match Flory-Huggins-Zuo equation of state (FHZ EoS) implying lateral connectivity within each sandstone (Chen et al., 2017). However, the offset between the two gradients indicates poor vertical connectivity between the two sandstones. Gas-oil ratio (GOR) and API gravity gradients do not exhibit offsets between the two sandstones even with limited vertical connectivity. However, asphaltene gradients are more reliable for the analysis because GOR error bars are relatively large, GOR gradients are small and the cubic EoS has many adjustable

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parameters. These connectivity predictions were confirmed by production history matching (Chen et al., 2018, Mullins, 2019). Despite poor vertical connectivity in the central fairway, methane carbon isotope analysis indicates that the biogenic methane fraction is invariant and significant (~ 2/3 of dissolved methane) throughout the oil column ($\delta^{13}C$ is ~-70‰ for biogenic methane; ~-40‰ for thermogenic methane).

Only a limited number of transport phenomena can drive mass transport in the reservoir over geologic time. Mass transport that gave rise to the excellent mixing of oil and gas in the studied reservoir must be explained. Natural convection requires a density inversion while for crude oils, small density variations caused by thermal gradients are often neglected (Mullins, 2019). Diffusion acts on crude oils and requires that the gas arrive first in the reservoir (Zuo et al., 2015). However, the reservoir formation is young (middle Pliocene) and the well spacing is over 1 km; thus, diffusion is not a candidate for the observed behavior as it would require longer than 100 million years to replicate the observed measurements (Fig. 2). This proves that oil arrived first in this reservoir (Mullins et al., 2023). Mass transport phenomena in tilted reservoirs also includes asphaltene colloidal instability accompanied by Stokes falling of asphaltene clusters onto the base of the interval, leading to Boycott convection, but this process cannot transport significant amounts of solution gas to the base (Chen et al., 2015; Mullins et al., 2020). Forced convection is the only remaining transport process that can explain the measured compositional distributions. Upon gas charge into an oil reservoir through a point source at/below the oil-water contact (OWC), gas migrates along the migration path crest, driven by its large buoyancy. The present-day reservoir has no gas cap even after solution gas almost tripled, meaning that the initial oil was significantly undersaturated and that added gas dissolved into the oil.

Reservoir Simulation and Base Case Model Condition. A simple 2D reservoir model was constructed with a Cartesian grid of size 200×1×50 ($X \times Y \times Z$ directions) and a 10° dip angle (Fig. 3). Grid cells have dimensions of 30×3000×10 (ft). Initially, stacked sandstones are saturated with dead oil (GOR = 0 MSCF/STB) with an oil saturation of 80% and irreducible water saturation of 20%, and underlain by an aquifer. The reservoir is isothermal (T = 100°C; P_{res} = 13000 psi); it is homogeneous and anisotropic. A black oil reservoir simulator is used for the analysis.

Examples

Figure 4 shows that excellent mixing results are obtained across most of the reservoir where gas dissolves immediately into oil. This behavior is consistent with the invariant $\delta^{13}C$ data shown in Fig. 2. However, fluid mixing outputs are sensitive to the presence of flow diverters (e.g., shale baffles and pinchouts). This is evident in Fig. 4, where we investigate the impacts of pinchout and charge point locations on present-day fluid realizations. Subtle variations of connectivity profiles and charge conditions lead to different GOR ranges and localized complex fluid gradients. Thus, our modeling can be used to deduce connectivity profiles.

Figure 5 shows that gas dissolves very quickly into oil at all mixing stages due to the effective convective cycles. The impact of both shale baffle and pinchout is clear on the convective streamlines and the resulting complex fluid gradients under the pinchout in the upper sandstone. Likewise, the baffle affects the pressure gradients which respond to complex fluid gradients leading to slightly different OWCs in the two stacked sandstones.

Conclusions

We quantify connectivity implications on oil chemistry based on numerical simulations, and dependent on the properties of the scour between stacked turbidites. The extent of mixing of biogenic gas and oil is accurately determined from measurement of methane carbon isotopes and gas composition. By matching the current fluid distributions, we use our understanding of fluid mixing processes to deduce connectivity profiles with high confidence, where pinchouts are beneath the detection limits of seismic amplitude measurements. The full range of reservoir realizations is predicted and the results are compared and contrasted against reservoirs located in the deepwater Gulf of Mexico. Modeling results reflect simple fluid mechanics, showing that oil charged first, then was followed by a biogenic gas charge. This sequence can be explained by the occurrence of gas chimneys. Results clearly indicate that reservoir structures significantly affect present-day mixing outcomes. Equivalent charge conditions with various geometrical properties such as scour location could lead to different spatial distributions of fluid properties, such as solution gas-oil ratio, fluid density, and asphaltene content.

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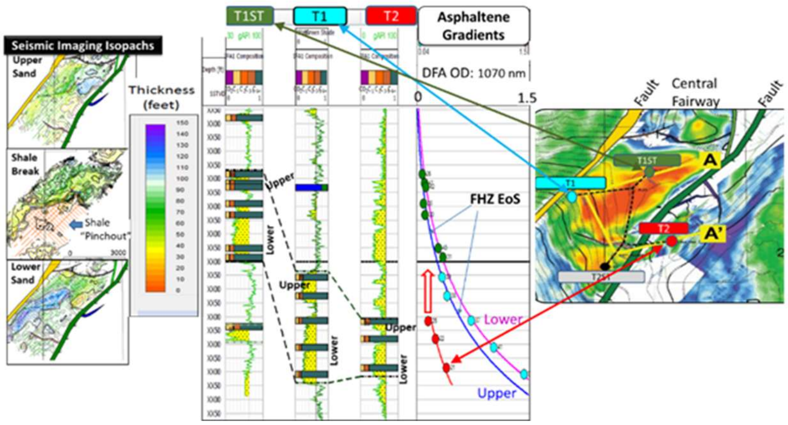

Figure 1: Deepwater reservoir located in the Gulf of Mexico and consisting of two stacked turbidite sandstones. Excellent lateral connectivity in each sandstone is verified through asphaltene gradient analysis; this is also confirmed via the isopach thickness maps of these sandstones (Mullins, 2019). Nonetheless, poor vertical connectivity between the two sandstones is clearly delineated by the offset of asphaltene gradients; seismic imaging overestimates the size of the shale pinchout (Chen et al., 2018; Mullins, 2019).

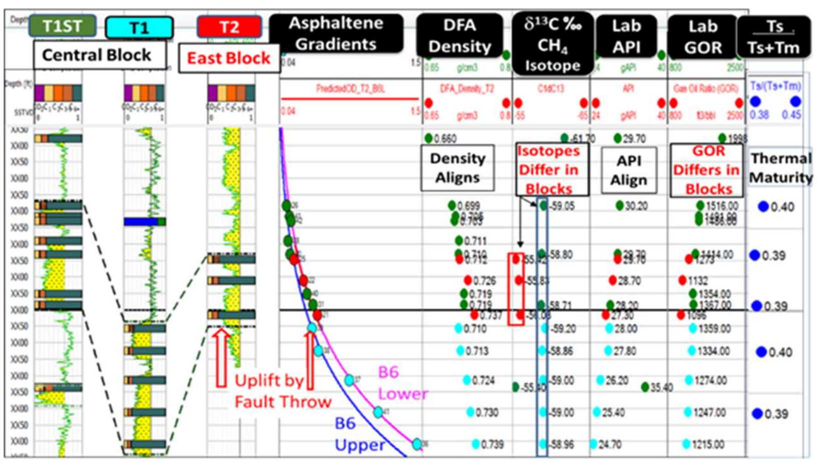

Figure 2: Well logs and fluid data acquired in the T1 and T1ST wells in the central fairway, and in T2 well in the downthrown block (Chen et al., 2018, Mullins, 2019). Asphaltene gradient data indicate that asphaltenes equilibrated across the field before fault threw. In this study, we investigate mixing process that gave rise to the invariant fraction of biogenic methane (proven by methane carbon isotopes) in both the upper and lower sandstones in the central fairway.

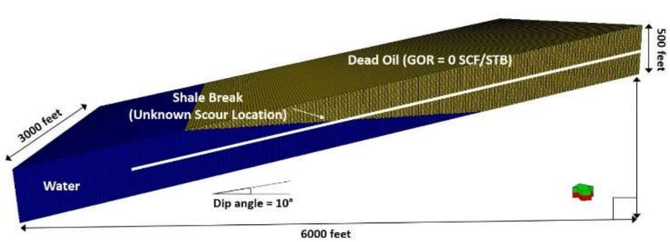

Figure 3: Base case model with a single grid cell in the *Y* direction implemented for 2D reservoir simulations of gas charge into undersaturated oil. The two stacked sandstones are poorly connected through a shale pinchout, where the scour location is one of the investigated parameters. A point charge of gas entry is located at the southwest close to the base of the aquifer (the green arrow points North). Throughout gas charge duration, the gas is added at the OWC and immediately dissolves into the oil. The model is tilted with a dip angle of 10°.

Connectivity Evaluation via Simulation of Charge

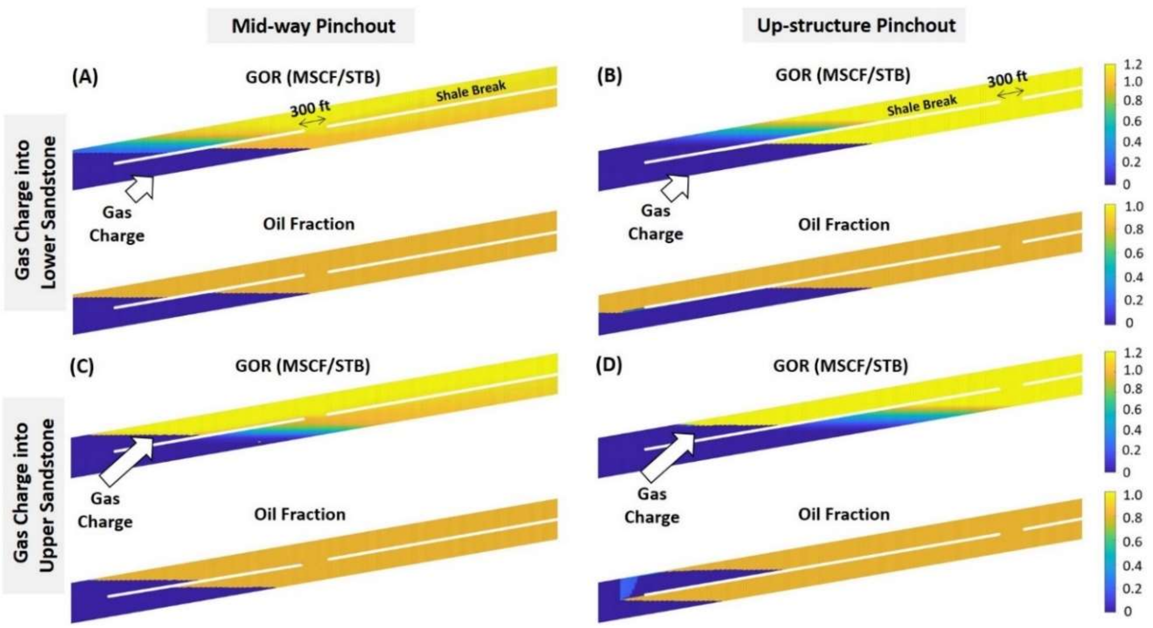

Figure 4: 2D simulations of a point gas source into a baffled, tilted oil reservoir below the OWC on the western flank. The GOR scale is color-coded (and water with zero MSCF/STB remains blue). Excellent mixing results where gas dissolves immediately into oil, which is consistent with methane carbon isotope data (Fig. 2). Here, the impacts of two parameters on fluid-mixing outputs are examined, (1) shale pinchout location, leading to different extents of mixing and complex fluid gradients (A and B) and (2) Gas charge point, leading to varying locations of complex fluid gradients (gas charge into upper sandstone in C and D as opposed to charge into lower sandstone in A and B). A charge duration of 100,000 years is assumed; results vary with charge duration only for very short, hence unrealistic durations.

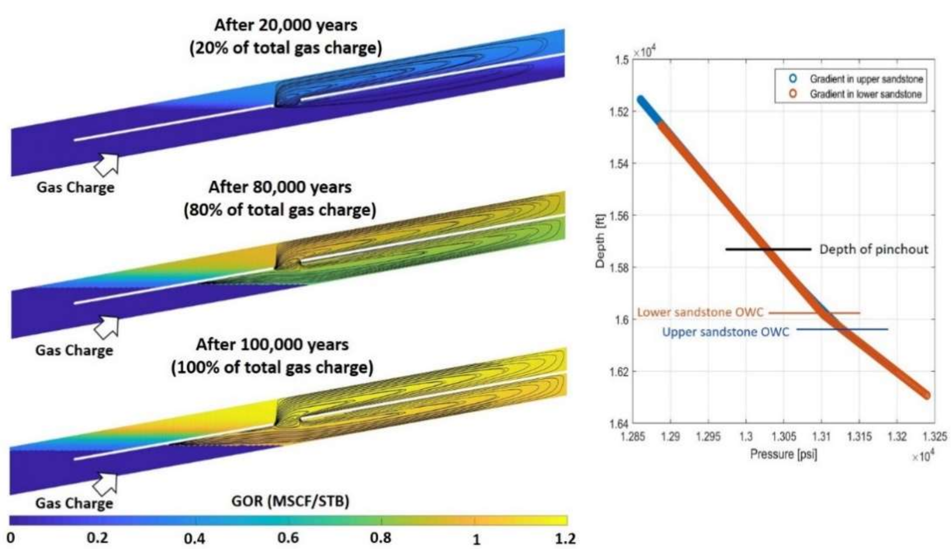

Figure 5: Convective streamlines generated at different stages of gas addition (affected by the presence of a baffle) show excellent mixing due to the convection of the buoyant high-GOR oil formed by the gas charge and dissolution of gas into oil (GOR values increase from zero up to 1200 MSCF/STB). A complex fluid gradient below the pinchout in the upper sandstone develops, affecting pressure gradients where a single initial OWC becomes slightly different OWCs in the two sandstones, maintaining similar hydrostatic pressures at the same heights.

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